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January 31, 2020

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Filing Center
P.O. Box 1088
201 High Street SE, Suite 100
Salem, Oregon 97301

Re: Docket No. LC 74
2019 Integrated Resource Plan ("IRP")
Amended 2019 Integrated Resource Plan and Appendices C and D

Attention Filing Center:

On July 19, 2019, Idaho Power Company ("Idaho Power" or "Company") filed a letter with the Idaho Public Utilities Commission ("Commission") providing notice that the Company had identified the need to perform supplemental analysis to confirm the accuracy of its 2019 IRP's conclusions and findings. The Commission subsequently issued a Notice of Application in Order No. 34410 suspending review of the filing until the supplemental analysis was filed.

Having now completed the supplemental analysis, Idaho Power is submitting for filing twenty (20) copies of Idaho Power Company's Amended 2019 IRP and Appendices C and D. As described in greater detail in the Amended 2019 IRP, the Company identified eight modifications to its modeling inputs to ensure more accurate modeling results including:

1) the addition of renewable energy certificate values for Jackpot Solar,
2) updating transmission interconnection costs for Jackpot Solar,
3) removing Franklin Solar from the list of available resources,
4) correcting the online date for Jackpot Solar,
5) allowing the model to correct the peak credit for new solar if Jackpot Solar is not selected,
6) introducing costs associated with natural gas supply expansion,

7) returning to the previous method of utilizing an after-tax discount rate for net present value calculations, and
8) including third-party transmission revenues associated with the Boardman-to-Hemingway transmission line.

In addition to these input modifications, the Company also implemented an additional modeling step to ensure that the capacity expansion model—which optimizes resource buildouts for the entire Western Electricity Coordinating Council ("WECC") region—yielded the best possible economic and reliability outcome for Idaho Power and its customers. To accomplish this, Idaho Power developed a hybrid solution in which it utilized the computer-based WECC-optimized model to develop 24 initial portfolios, then performed a manual process to modify a subset of the top-performing portfolios, with the ultimate goal of improving upon the modeled results and arriving at a least-cost, least-risk portfolio specific to Idaho Power.

While there were multiple changes to the analysis, it resulted in only two changes impacting the Company's preferred portfolio near-term 2019–2026 Action Plan. First, the Company elected to forego the option to enter into a power purchase agreement with the 100 megawatt ("MW") Franklin Solar facility. Because this resource is no longer an option, it was removed from the modeling and the subsequent preferred portfolio. Second, the Preferred Portfolio in the Company's filed IRP included the addition of 5 MW of demand response in 2026; in the Amended 2019 IRP, the procurement of demand response shifted later in the planning period, to 2031. Also, the Company updated Amended 2019 IRP and Appendices C and D to reflect certain events and data through year-end 2019.

Idaho Power respectfully requests the Commission issue a scheduling order to facilitate public review of the filing. Please contact me at (208) 388-5825 if you have any questions.

Very truly yours,

Lisa F. Rackner

Attachments

IDAHO POWER®
An IDACORP Company

INTEGRATED RESOURCE PLAN

2019

AMENDED • JANUARY • 2020

BALANCING OUR ENERGY NEEDS • TODAY AND TOMORROW

SAFE HARBOR STATEMENT

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GLOSSARY OF ACRONYMS

A/C—Air Conditioning
AC—Alternating Current
ACE—Affordable Clean Energy
AECO—Alberta Energy Company
AFUDC—Allowance for Funds Used During Construction
AgI—Silver Iodide
akW—Average Kilowatt
aMW—Average Megawatt
ATB—Annual Technology Baseline
ATC—Available Transfer Capacity
B2H—Boardman to Hemingway
BLM—Bureau of Land Management
BPA—Bonneville Power Administration
CAA—*Clean Air Act of 1970*
CAISO—California Independent System Operator
CAMP—Comprehensive Aquifer Management Plan
CBM—Capacity Benefit Margin
CCCT—Combined-Cycle Combustion Turbine
CEM—Capacity Expansion Model
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
CPP—Clean Power Plan
CSPP—Cogeneration and Small-Power Producers
CWA—*Clean Water Act of 1972*
DC—Direct Current
DOE—Department of Energy
DPO—Draft Proposed Order
DSM—Demand-Side Management
EFSC—Energy Facility Siting Council
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 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
GHG—Greenhouse Gas
GPCM—Gas Pipeline Competition Model
GWMA—Ground Water Management Area
HB—House Bill
HCC—Hells Canyon Complex
HRSG—Heat Recovery Steam Generator
IDWR—Idaho Department of Water Resources
IEPR—Integrated Energy Policy Report
IGCC—Integrated Gasification Combined Cycle
INL—Idaho National Laboratory
IPMVP—International Performance Measurement and Verification Protocol
IPUC—Idaho Public Utilities Commission
IRP—Integrated Resource Plan
IRPAC—IRP Advisory Council
ISEA—Idaho Strategic Energy Alliance
IWRB—Idaho Water Resource Board
kV—Kilovolt
kW—Kilowatt
kWh—Kilowatt-Hour
LCOC—Levelized Cost of Capacity
LCOE—Levelized Cost of Energy
LDC—Load-Duration Curve
Li—Lithium Ion
LiDAR—Light Detection and Ranging
LNG—Liquefied Natural Gas
LOG—Low Oil and Gas
LOLP—Loss-of-Load Probability
LTCE—Long-Term Capacity Expansion
LTP—Local Transmission Plan
m^2—Square Meters
MATL—Montana–Alberta Tie Line
MOU—Memorandum of Understanding

MSA—Metropolitan Statistical Area
MW—Megawatt
MWAC—Megawatt Alternating Current
MWh—Megawatt-Hour
NEEA—Northwest Energy Efficiency Alliance
NEPA—*National Environmental Policy Act of 1969*
NERC—North American Electric Reliability Corporation
NLDC—Net Load-Duration Curve
NOx—Nitrogen Oxide
NPV—Net Present Value
NREL—National Renewable Energy Laboratory
NTTG—Northern Tier Transmission Group
NWPCC—Northwest Power and Conservation Council
NYMEX—New York Mercantile Exchange
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
OFPC—Official Forward Price Curve
OPUC—Public Utility Commission of Oregon
ORS—Oregon Revised Statute
P14—Portfolio 14
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
RICE—Reciprocating Internal Combustion Engine
RMJOC—River Management Joint Operating Committee
ROD—Record of Decision
ROR—Run-of-River
ROW—Right-of-Way
RPS—Renewable Portfolio Standard

RTF—Regional Technical Forum
SCCT—Simple-Cycle Combustion Turbine
SCR—Selective Catalytic Reduction
SMR—Small Modular Reactor
SNOWIE—Seeded and Natural Orographic Wintertime Clouds: the Idaho Experiment
SO_2—Sulfur Dioxide
SRBA—Snake River Basin Adjudication
SRPM—Snake River Planning Model
T&D—Transmission and Distribution
TRC—Total Resource Cost
UAMPS—Utah Associated Municipal Power Systems
US—United States
USBR—United States Bureau of Reclamation
USFS—United States Forest Service
VER—Variable Energy Resources
VRB—Vanadium Redox-Flow Battery
WECC—Western Electricity Coordinating Council

AMENDED 2019 IRP EXECUTIVE SUMMARY

Introduction and Background

Idaho Power filed its *2019 Integrated Resource Plan* on June 28, 2019. Based on comments received during the development of the 2017 IRP, Idaho Power elected to use the AURORA software's Long Term Capacity Expansion (LTCE) modeling capability to develop portfolios for the 2019 IRP, reflecting a departure from its long-standing methodology of manually developing portfolios to eliminate resource deficiencies identified through a load and resource balance. The filing of the 2019 IRP represented the first iteration of the company's resource plan utilizing a computer-based model to develop future resource portfolios.

For reasons described in detail in this Executive Summary, following the filing of the 2019 IRP Idaho Power identified the need to suspend the processing of its plan due to concerns with the modeling output. Consequently, on July 19, 2019, the company filed letters with both the Idaho and Oregon public utilities commissions providing notification that additional time was needed to perform supplemental analysis to confirm the 2019 IRP's conclusions and findings. In November 2019, Idaho Power provided notice that it would file its Amended 2019 IRP no later than January 31, 2020.

This document reflects the culmination of the supplemental analysis performed by Idaho Power following the submission of its initial 2019 IRP in June. It should be noted that the changes detailed in this Executive Summary impacted multiple phases of IRP preparation; therefore, this document and the associated appendices are intended to replace the initial documents filed on June 28, 2019 in their entirety. For the sake of clarity, the company believes that a new standalone set of documents offers a clear representation of the 2019 IRP's findings and conclusions, rather than attempting to provide an addendum that attempts to identify elements that changed and those that did not.

Cause for Filing Suspension

As discussed in detail in this document, the LTCE capability of the AURORA model selects from a variety of supply- and demand-side resource options to develop portfolios optimal for given alternative future scenarios, with the objective of meeting a 15-percent planning margin and regulating reserve requirements associated with balancing load and intermittent resources output. The model can also simulate retirement of existing generation units, and build resources that are economic absent a defined capacity need.

While the 2019 IRP was in development, a time-limited opportunity to purchase the output of a 120 megawatt (MW) solar facility (Jackpot), with the option of an additional 100 MW (Franklin), was presented to Idaho Power. Because Idaho Power was in the development phase of the 2019 IRP, the basic structure of the Jackpot and Franklin power purchase agreement (Solar PPA) was included in the IRP's LTCE analysis. As detailed in Idaho Power's filed 2019 IRP, the LTCE model selected both Jackpot and Franklin as optimal resources in the company's preferred portfolio.

Idaho Power's determination that additional analysis was needed for the 2019 IRP originated in the processing of the case to approve the Solar PPA. While performing analyses necessary to support approval of the PPA in that case—and what ultimately led to the conclusion that additional investigation was warranted—Idaho Power discovered that when it forced the model to make a decision that was counter to the optimized result, overall portfolio costs for Idaho Power decreased in certain cases. Based on these counterintuitive results, Idaho Power filed the aforementioned request to suspend processing of its 2019 IRP, and performed a comprehensive review of the LTCE methodology and the corresponding modeling inputs to identify the potential cause and ensure its analyses developed the most accurate results possible.

LTCE Modeling Review

First, the Company identified the regional LTCE modeling parameters as one possible area driving these counterintuitive results. In order to model appropriate market conditions for the Western Electricity Coordinating Council (WECC), the LTCE model logic optimizes resource build-out portfolios for the entire region, not just Idaho Power. Consequently, Idaho Power was concerned that the WECC-optimized LTCE runs were optimizing resources for the region, but not necessarily for Idaho Power and its customers.

To test this, Idaho Power performed a new set of LTCE runs where it first optimized the 20-year future for the WECC, then locked down the WECC resource buildout and re-ran the LTCE model specifically calibrated to optimize Idaho Power's service area. However, these modified runs did not yield consistently lower cost results for Idaho Power than the prior runs optimized for the WECC. Based on these results, Idaho Power determined that a fully computer-based optimization was not a feasible method at this time for ensuring that the modeling reasonably identified the least-cost, least-risk portfolio for Idaho Power's customers.

In place of fully computer-based modeling, Idaho Power developed a hybrid solution in which it utilized the WECC-optimized LTCE model to develop 24 initial portfolios, then performed a manual process to modify a subset of the top-performing portfolios, with the ultimate goal of improving upon the modeled results and arriving at least-cost, least-risk portfolio specific to Idaho Power. This manual process generally evaluates the level of reserves on the system on an annual basis, then modifies resource additions and retirements manually to see if a more economically optimal result can be achieved. This process, discussed in detailed in Chapter 9, focuses on the retirement dates for units at the Jim Bridger Coal Plant (Bridger), to ensure the shutdown dates of these units are developed to yield the best possible economic and reliability outcome for Idaho Power and its customers.

Modeling Input Review

In addition to the reevaluation of the LTCE model and the implementation of the manual adjustment process, Idaho Power performed a comprehensive review of all modeling inputs feeding into the development of the 2019 IRP. Through this review, Idaho Power identified eight modifications to its modeling inputs to ensure more accurate modeling results. These results, described in more detail in the sections that follow, include: 1) the addition of renewable energy certificate (REC) values for Jackpot Solar, 2) updating transmission interconnection costs for Jackpot Solar, 3) removing Franklin Solar from the list of available resources, 4) correcting the online date for Jackpot Solar, 5) allowing the model to correct the peak credit for new solar if

Jackpot Solar is not selected, 6) introducing costs associated with natural gas supply expansion, 7) returning to the previous method of utilizing an after-tax discount rate for net present value calculations, and 8) including third party transmission revenues associated with the Boardman-to-Hemingway transmission line (B2H).

1. REC Values for Jackpot Solar

Through Idaho Power's comprehensive review of all modeling inputs, it was determined that potential REC revenues associated with the Jackpot Solar PPA were inappropriately excluded from Idaho Power's costing models. Therefore, the amended analysis includes potential benefits associated with REC sales from the Jackpot Solar PPA based upon the same REC value forecast applied to other solar resources analyzed in this IRP.

2. Transmission Interconnection Costs for Jackpot Solar

Prior to the time that Jackpot Solar approached Idaho Power with a proposal to sell its generation to Idaho Power, Jackpot Solar had completed the interconnection study process as a non-PURPA, independent power producer pursuant to the Open Access Transmission Tariff (OATT). The project was studied for interconnection as an Energy Resource (ER), which looks only at required facilities and upgrades needed to connect to Idaho Power's system, without looking at the deliverability requirements or upgrades required to deliver its output to a particular location or load. Such evaluation and/or studies would be done subsequently at the time when the project made a request to deliver its output, as a point-to-point transmission service request, or if selling to Idaho Power as an Idaho Power Designated Network Resource. Pursuant to its request, the project was initially studied as an ER identifying a new substation at the point of interconnection that connected to the Midpoint-NV/ID Border 345-kV line in a tap configuration.

Jackpot subsequently approached Idaho Power proposing to sell the project's output to Idaho Power, and Idaho Power eventually entered into a PPA with the developer, thus changing the status of the project and the type of interconnection. Once Idaho Power had a contract to take the generation from the project, it required Idaho Power's merchant function to submit a Transmission Service Request for Network Integration Transmission Service, which required the project to be studied for the deliverability of its output as an Idaho Power Network Resource ("NR"). The requested transmission service requires the transfer of the project's energy across Idaho Power's internal transmission system to serve Idaho Power's native load. As a result, and in order to provide the requested Network Integration Transmission Service, a more robust ring-bus configuration was required, as opposed to the previously identified tap configuration for ER service, totaling approximately $11 million in network upgrades in order to serve Idaho Power load as a Designated Network Resource. Due to the project's status as a non-PURPA NR, the identified Network Upgrades are funded by the Transmission Provider, Idaho Power Transmission, as required by the OATT. Based on this change, the company updated cost inputs associated with Jackpot Solar to reflect the incremental transmission investment that would be funded by Idaho Power.

3. Removal of Franklin Solar

On October 23, 2019, Idaho Power filed comments in IPUC Case No. IPC-E-19-14, updating the IPUC that on October 18, 2019, it delivered notice stating that the company elected not to exercise its right and option to purchase the 100 MW of additional output related to the Franklin Solar project. Because Idaho Power elected to forego this project, it was removed from the stack of available resources within the LTCE model.

4. Corrected Online Date for Jackpot Solar

The current scheduled operating date for Jackpot Solar is December 1, 2022. In initial modeling runs, the selection of a 2022 operating year within the model resulted in a scenario in which generation started at the beginning of the year, or eleven months prior to the scheduled operating date indicated in the contract. To better align the modeled online date with the expected online date from the contract, the modeled year was adjusted to 2023 with generation output starting January 1, 2023, or one month after the scheduled operating date.

5. Peak Capacity Credit for Solar Resources

The solar peak-hour capacity credit on a by-project basis is provided in tabular and graphic format in the Supply-Side Resource Data section of the *Amended 2019 IRP Appendix C: Technical Report*. In the initial application, Jackpot Solar comprised projects 1 through 3, Franklin Solar comprised projects 4 and 5, and generic solar comprised projects 6 through 24. In the latest portfolios developed by AURORA, Franklin Solar was removed and generic solar now comprises projects 4 through 24.

AURORA has the ability to individually model the capacity value for each project, but these values are directly assigned. Therefore, if Jackpot is not selected, the values for the other projects remain as assigned. The current version of AURORA lacks the capability to dynamically adjust peak-hour solar capacity contributions when Jackpot is not selected, but other solar resources are selected in later years. It should be noted, however, that the impact of this modeling limitation in AURORA is relatively small, as the difference in capacity value between the average of projects 1 through 3 (Jackpot Solar) and Project 4 (the next project in the queue) is only 2.9 MW (see the *Amended 2019 IRP Appendix C: Technical Report*).

6. B2H Transmission Revenue Credits

For modeling purposes in the filed June 2019 IRP, transmission revenue credits associated with B2H were excluded because Idaho Power initially felt that a conservative approach was appropriate for evaluating this resource. These credits reflect the estimated incremental transmission wheeling revenue from non-native load customers as a result of B2H.

However, through the Idaho Power's comprehensive re-evaluation of all inputs into its IRP modeling runs, it determined that it is appropriate to include all relevant cost and benefit information associated with each resource type, including incremental transmission revenues from B2H. Therefore, portfolios developed as part of the Amended 2019 IRP now include these amounts, which is consistent with the methodology utilized in the 2017 IRP.

7. Discount Rate Modification

The discount rate used to develop the Amended 2019 IRP was reduced from 9.59 to 7.12 percent, reflecting the after-tax weighted-average cost of capital (WACC). The original discount rate used in the 2019 IRP financial modeling utilized Idaho Power's WACC plus a tax gross-up for the equity-financed portion of the overall costs. This represented a change from prior IRPs, in which the traditional WACC was used for all discounting calculations. While both methods (pre-tax and post-tax) are reasonably considered and analytically sound, Idaho Power originally believed the higher discount rate may better align with the customer cost perspective, as it reflects the total financing costs customers will actually pay through rates.

However, while conducting the supplemental IRP analyses following the filing of the 2019 IRP, Idaho Power observed that the use of the higher discount rate was having a material impact on the timing and nature of investments included in the various portfolio runs, particularly those portfolios modeled under expected case assumptions. It was not Idaho Power's intent for the change in discount rate methodology to serve as a major driver of changes to its long-term planning outcomes, especially at a time when other significant modifications to the analytical framework were being implemented, such as the introduction of computer-based LTCE modeling. As a result, Idaho Power has returned to the prior practice of applying its internal after-tax WACC as the discount rate for the Amended 2019 IRP until more evaluation and vetting of alternative methodologies can occur. This approach remains consistent with prior years' IRPs and may be more understandable as a general indicator of value in the near-term.

8. Natural Gas Pipeline and Capacity Considerations

While reviewing the modeling inputs, Idaho Power determined that certain costs associated with the procurement of incremental natural gas supply should be incorporated into the model; therefore, additional fixed costs associated with future natural gas resources have been added. These modifications, discussed in depth in Chapter 7, reflect the cost of ensuring pipeline transportation capacity utilizing existing infrastructure, as well as the cost of pipeline expansion if projected gas generation exceeds a certain threshold.

Impact to Preferred Portfolio

The remainder of this document reflects Idaho Power's Amended 2019 IRP, incorporating all modeling and input changes detailed in this Executive Summary. It is important to note that while there were multiple changes to the analysis, it resulted in only two changes impacting Idaho Power's preferred portfolio near-term 2019–2026 Action Plan.

First, Idaho Power elected to forego the option to enter into a PPA with the 100 MW Solar Franklin facility. Because this resource is no longer an option, it was removed from the modeling and the subsequent preferred portfolio. Second, the preferred portfolio in Idaho Power's filed IRP included the addition of 5 MW of demand response (DR) in 2026; in the Amended 2019 IRP, the procurement of DR shifted later in the planning period, to 2031.

Overall, the results of the Amended 2019 IRP reflect a number of key components that position Idaho Power to reliably and cost-effectively serve load in the 20-year planning period. The B2H transmission line continues to be a top performing resource alternative, providing Idaho Power access to clean and low-cost energy in the Pacific Northwest wholesale electric market.
The Amended 2019 IRP also indicates favorable economics associated with Idaho Power's exit from five of seven coal-fired generating units by the end of 2026 and exit from the remaining two units at the Jim Bridger facility by the end of the 2020s. The 2019–2026 Action Plan also

includes the addition of 120 MW of solar through the construction of the Jackpot Solar Facility at year-end 2022.

Conclusion

Idaho Power appreciates the patience of the Idaho and Oregon public utility commissions, their staffs, members of the IRPAC, and other stakeholders as Idaho Power worked through the modeling challenges presented by its first year utilizing a computer-based optimizer to construct resource portfolios. Idaho Power has learned valuable lessons throughout this process, and believes the resulting Amended 2019 IRP presents the least-cost, least-risk future for Idaho Power and its customers.

1. Overview

Introduction

The 2019 Integrated Resource Plan (IRP) is Idaho Power's 14th resource plan prepared in accordance with 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 and flexible capacity 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 2019 IRP evaluates the 20-year planning period from 2019 through 2038. During this period, Idaho Power's load is forecasted to grow by 1.0 percent per year for average energy demand and 1.2 percent per year for peak-hour demand. Total customers are expected to increase from 550,000 in 2018 to 775,000 by 2038. Additional resources will be needed to meet these increased demands.

Currently, 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 and depends on updated streamflow projections and criteria to use in resource adequacy planning. Further discussion of Idaho Power's IRP planning criteria can be found in Chapter 7.

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 use. 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 Idaho Power coordinates transmission planning as a member of the Northern Tier Transmission Group (NTTG). Idaho Power is obligated under Federal Energy Regulatory Commission (FERC) regulations to plan and expand its local transmission system to provide requested firm transmission service to third parties and to construct and place in service sufficient transmission capacity to reliably deliver energy and capacity to network customers[1] and Idaho Power retail customers.[2] The delivery of energy, both within the Idaho Power system and through regional transmission interconnections, is of increasing importance for several reasons. First, adequate transmission is essential for robust participation in the Energy Imbalance Market (EIM) and second, it is necessary in a future with high penetrations of variable energy resources (VER) and their associated intermittent production. The timing of new transmission projects is subject to complex permitting, siting, and regulatory requirements and coordination with co-participants.

Public Advisory Process

Idaho Power has involved representatives of the public in the resource planning process since the early 1990s. The public forum is known as the IRP Advisory Council (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 the staff of the Idaho Public Utilities Commission (IPUC) and the Oregon Public Utility Commission (OPUC), 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 2019 IRPAC members can be found in *Appendix C—Technical Appendix*.

For the 2019 IRP, Idaho Power facilitated eight IRPAC meetings, and then two more for the Amended 2019 IRP. In response to stakeholder feedback for the 2019 IRP, Idaho Power implemented and maintained an online forum for stakeholders to submit requests for information and for Idaho Power to provide responses to information requests. The forum allows stakeholders to develop their understanding of the IRP process, particularly its key inputs, consequently enabling more meaningful stakeholder involvement during the process.

IRP Methodology

The primary goal of the IRP is to ensure Idaho Power's system has sufficient resources to reliably serve customer demand and flexible capacity needs over the 20-year planning period. The company has historically developed portfolios to eliminate resource deficiencies identified in a 20-year load and resource balance. Under this process, Idaho Power developed portfolios that were quantifiably demonstrated to eliminate the identified resource deficiencies, and qualitatively varied by resource type, in which the considered resource types reflected Idaho Power's understanding that the economic performance of a resource class is dependent on future conditions in energy markets and energy policy.

Idaho Power received comments on the 2017 IRP encouraging the use of Capacity Expansion Modeling (CEM) for 2019 IRP portfolio development. In response, the company elected to use the AURORA model's capacity expansion modeling capability to develop portfolios for the 2019

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

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

IRP. Under this process, the alternative future scenarios are formulated first, and then the AURORA model is used to develop portfolios optimal to the selected alternative future scenarios. For example, the AURORA (CEM) model can be expected under an alternative future scenario having high natural gas price and/or high cost of carbon to develop a portfolio having substantial expansion of non-carbon emitting VER, because a portfolio is likely to be economic under such a scenario.

The use of capacity expansion modeling has resulted in a departure from Idaho Power's formerly employed practice of developing resource portfolios to specifically eliminate resource deficiencies identified by a load and resource balance. Under the capacity expansion modeling approach used for the 2019 IRP, the AURORA model selects from the variety of supply- and demand-side resource options to develop portfolios that are least-cost for the given alternative future scenarios with the objective of meeting a 15-percent planning margin *and* regulating reserve requirements associated with balancing load and wind- and solar-plant output. The model can also select to retire existing generation units, as well as build resources based on economics absent a defined capacity need. The capacity expansion modeling process is discussed in further detail in Chapter 8. As will be discussed in Chapter 9, to ensure the AURORA-produced portfolios provide customers reliable and affordable energy, Idaho Power selected a subset of top-performing AURORA-produced portfolios to determine if additional resource modifications—primarily accelerated coal retirements—could further reduce costs and help achieve Idaho Power's green commitments more quickly. Going forward, these modifications are referred to as "manual adjustments".

To meet objectives for planning margin and regulating reserve requirements, the AURORA model accounts for the capability of the existing system and selects from the pool of new supply- and demand-side resource options only when the existing system comes short of meeting the objectives. Existing supply-side resources include generation resources and transmission import capacity from regional wholesale electric markets. Existing demand-side resources include current levels of demand response and savings from current energy efficiency programs and measures.

Idaho Power conducts a financial analysis of costs and benefits of the developed portfolios. The financial costs include construction, fuel, O&M, transmission upgrades associated with interconnecting new resource options, natural gas pipeline reservation or new natural gas pipeline infrastructure, projected wholesale market purchases, and anticipated environmental controls. The financial benefits include economic resource options, projected wholesale market sales, and the market value of renewable energy certificates (REC) for REC-eligible resources.

Idaho Power's balancing area is part of the larger western interconnection. Idaho Power must balance loads and generation per North American Electric Reliability Corporation (NERC) system reliability standards. For example, during times of acute oversupply (with no ability to sell into the market), 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. Since 2009, the addition has been called the Boardman to Hemingway (B2H) Transmission Line Project and the project has been included in the four subsequent IRPs. Idaho Power again evaluated the B2H transmission line in the 2019 IRP to ensure the transmission addition remains a prudent resource acquisition. Further discussion of the treatment of B2H in the 2019 IRP's capacity expansion modeling is provided in Chapter 8.

IRPs address Idaho Power's long-term resource needs. Near-term energy and capacity needs are planned in accordance with Idaho Power's *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* provide guidelines for Idaho Power's physical and financial hedging, and are designed to systematically identify, quantify, and manage the exposure of the company and its customers to uncertainties related to the energy markets in which Idaho Power is an active participant. The *Energy Risk Management Policy* and *Energy Risk Management Standards* specify an 18-month load and resource review period, and Idaho Power assesses the resulting operations plan monthly.

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) (see figures 1.1 and 1.2). The overall declining trends in terms of both CO2 emissions intensity and total CO2 emissions demonstrates Idaho Power's commitment to reducing CO_2 emissions. The preferred portfolio was selected in part to further the company's pathway to reduced emissions.

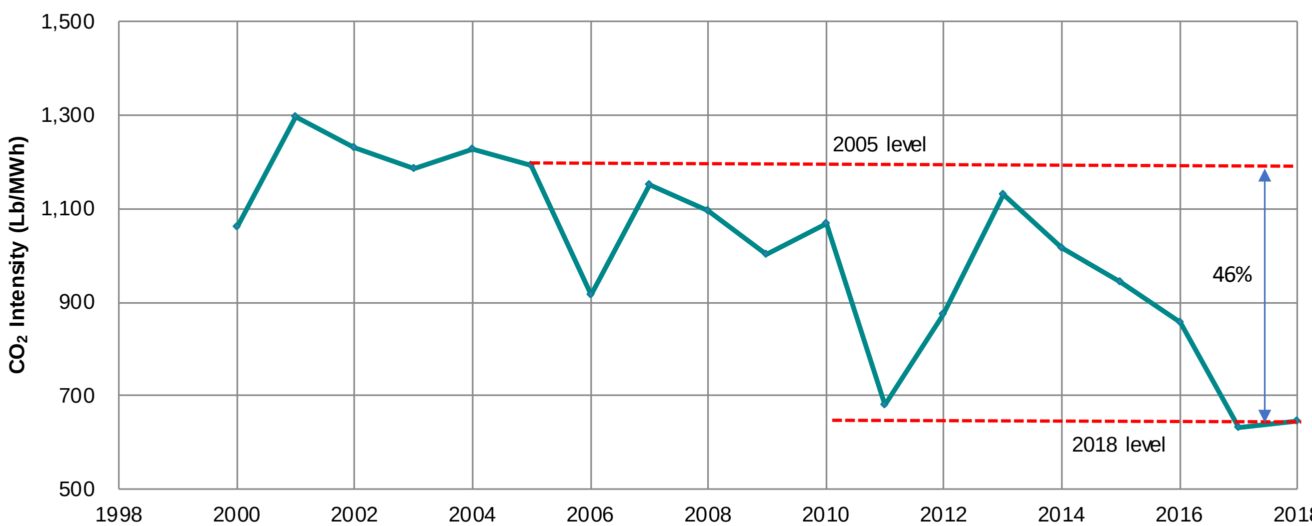

Figure 1.1 Estimated Idaho Power CO_2 emissions intensity

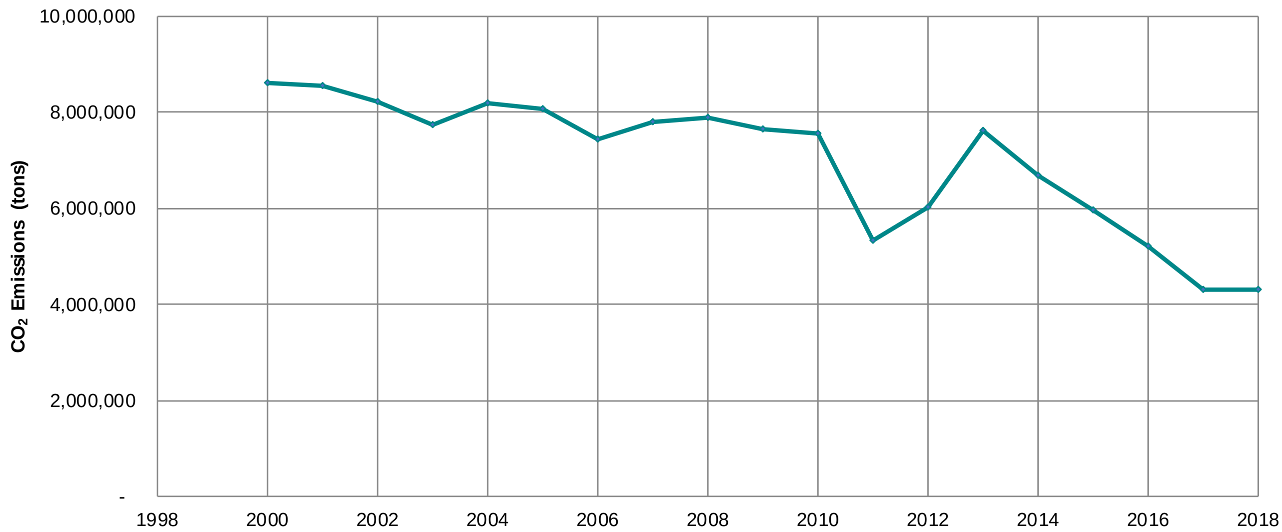

Figure 1.2 Estimated Idaho Power CO_2 emissions

CO_2 Emissions Reduction

Idaho Power is committed to reducing the amount of CO_2 energy-generating sources emit. Since 2009, the company has met various voluntary goals, initiated by shareholders, to realize its commitment to CO_2 reduction. As of 2018, Idaho Power's carbon emissions intensity, expressed as pounds of CO_2 per MWh generated, has decreased by 46 percent compared to 2005.

Our current goal is to ensure the average CO_2 emissions intensity of our energy sources from 2010 to 2020 is 15- to 20-percent lower than 2005 levels.

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

The portfolio analysis performed for the 2019 IRP assumes carbon emissions are subject to a per-ton cost of carbon. The forecasts for carbon cost are provided in Chapter 8 of the IRP. Projected CO_2 emissions for each analyzed resource portfolio are provided in Chapter 9 of the IRP.

Idaho Power Clean Energy Goal—Clean Today. Cleaner Tomorrow.™

Developed based on customer and stakeholder input, in March 2019, Idaho Power announced a goal to provide 100 percent clean energy by 2045. This goal furthers Idaho Power's legacy of being a leader in clean energy. Key to achieving this goal of 100 percent clean energy is the company's existing backbone of nearly 50 percent hydropower, as well as continuing to reduce carbon emissions and exiting participation in its share of three coal plants. In addition, Idaho Power reached an agreement to buy 120 megawatts (MW) of solar power from a private developer; this agreement was recently approved by the IPUC in December 2019.

The preferred portfolio identified in this 2019 IRP reflects a mix of generation and transmission resources that ensures reliable, affordable energy using technologies available today. Achieving our clean-energy goal will require new technological advances and cost-breakthroughs, as well as a continued focus on energy efficiency and demand-response programs. As it has over the past decade, the advisory council will continue to play a key role in updating the IRP every two years, analyzing new technologies and continuing our path toward a cleaner tomorrow.

Portfolio Analysis Summary

Using the AURORA Long-Term Capacity Expansion (LTCE) model, Idaho Power produced 24 different portfolios using a combination of three natural gas price forecasts and four carbon emissions adders all under two futures: one with B2H and one without. The 24 portfolios include an increase in the types of resource additions and a wider range of quantities of those resources compared to the 2017 IRP. The 24 portfolios for 2019 include varied amounts of nameplate generation additions:

- Wind (between 0 and 1,200 MW)
- Solar (between 0 and 1,170 MW)
- Natural Gas Reciprocating Engines (between 0 and 444 MW)
- Natural Gas Combined-Cycle Combustion Turbine (CCCT) (between 0 and 600 MW)
- DSM (between 0 and 50 MW)
- Battery storage (between 0 and 160 MW)
- Nuclear (between 0 and 180 MW)
- Biomass (between 0 and 210 MW)
- Natural Gas Simple-Cycle Combustion Turbine (SCCT) (between 0 and 170 MW)
- Accelerated Jim Bridger Coal unit retirements (between 0 and 708 MW)

The diversity of resource mixes in the 24 portfolios is an important result from the analysis. Each portfolio is built using the various natural gas and carbon scenarios within an optimized Western Electricity Coordinating Council (WECC) LTCE, illustrating the many combinations of resources that could result in a reliable system for customers at varying costs.

The 2019 preferred portfolio continues the trend away from using existing coal units as has been seen since the 2015 IRP, which found economic early exits from Valmy units 1 and 2. The 2017 IRP preferred portfolio included early exits from two units at Jim Bridger in 2028 and 2032. The 2019 IRP analysis has determined it is economical to exit all four coal units early at Jim Bridger.

The portfolios are also evaluated based on an assessment of the likelihood of the various natural gas prices, carbon prices, and B2H futures. The planning case futures represent Idaho Power's assessment of the mostly likely future forecasts of the primary known variables. The portfolios are also run against additional futures to identify the costs sensitivity of various resource mixes to alternative futures that helps inform Idaho Power's 20-year action plan. Identifying and focusing on common near-term resource elements that appear in multiple futures, or identifying futures with a low likelihood, but high costs is a pragmatic way to assess resource choices.

Based on the results of the additional modeling described in the Executive Summary and in Chapter 9, Portfolio 16(4) and Portfolio 14(7) yield the 2019 Amended IRP preferred portfolio.[3] This preferred portfolio was derived from both the AURORA LTCE-produced Portfolio 16 and Portfolio 14, with additional manual adjustments to ensure the portfolios reflected a least-cost, least-risk future specifically for Idaho Power and its customers. The manual adjustment process is discussed in more detail in Chapter 9.

Table 1.1, below shows the resource additions and coal exits that characterize the preferred portfolio over the 20-year planning period:

Table 1.1 Preferred portfolio additions and coal exits (MW)

	Gas	Wind	Solar	Battery	Demand Response	Coal Exit
2019						-127
2020						-58
2021						
2022			120			-177
2023						
2024						
2025						-133
2026						-180
2027						
2028						-174
2029			40	30		
2030	300					-177
2031					5	
2032			80	10	5	
2033			80	20	5	
2034			80	20	5	
2035	111				5	
2036					5	
2037			320			
2038		300	440			
Nameplate Total	**411**	**300**	**1,160**	**80**	**30**	**-1,026**
B2H (2026)	500					

[3] Portfolio 4 was selected as the Preferred Portfolio in the original 2019 IRP filed in June 2019.

Action Plan (2019–2026)

The 2019 IRP action plan is the culmination of the IRP process distilled into near-term actionable items. The action plan identifies key milestones to successfully position Idaho Power to provide reliable, economic and environmentally sound service to our customers into the future. The current regional electric market, regulatory environment, pace of technological change and Idaho Power's recently announced goal of 100 percent clean energy by 2045 make the 2019 action plan especially germane.

The action plan associated with the preferred portfolio is driven by its core resource actions through the mid-2020s. These core resource actions include:

- 120 MW of added solar PV capacity (2022)
- Exit from three coal-fired generating units by year-end 2022 (including Valmy 1 at year-end 2019), and from five coal-fired generating units (total) by year-end 2026
- B2H on-line in 2026

The preferred portfolio also is characterized by the following attributes:

- Optionality
- Flexible capacity

The action plan is the result of the above resource actions and portfolio attributes, which are discussed in the following sections.

Further discussion of the core resource actions and attributes of preferred portfolio is included in Chapter 10. A chronological listing of the plan's actions follows in Table 1.2.

Table 1.2 Action Plan (2019–2026)

Year	Action
2019–2022	Plan and coordinate with PacifiCorp and regulators for early exits from Jim Bridger units. Target dates for early exits are one unit during 2022 and a second unit during 2026. Timing of exit from second unit coincides with the need for a resource addition.
2019-2022	Incorporate solar hosting capacity into the customer-owned generation forecasts for the 2021 IRP.
2019	Jackpot Solar PPA regulatory approval*—on-line December 2022
2019	Exit Valmy Unit 1 by December 31, 2019.*
2019–2021	Conduct ongoing B2H permitting activities. Negotiate and execute B2H partner construction agreement(s).
2019–2026	Conduct preliminary construction activities, acquire long-lead materials, and construct the B2H project.
2019–2020	Monitor VER variability and system reliability needs, and study projected effects of additions of 120 MW of PV solar (Jackpot Solar) and early exit of Bridger units.
2020	Exit Boardman December 31, 2020.
2020	Bridger Unit 1 and Unit 2 Regional Haze Reassessment finalized.
2020	Conduct a VER Integration Study.

2021–2022	Continue to evaluate and coordinate with PacifiCorp for timing of exit/closure of remaining Jim Bridger units.
2022	Subject to coordination with PacifiCorp, exit Jim Bridger unit (as yet undesignated) by December 31, 2022.
2022	Jackpot Solar 120 MW on-line December 2022.
2023–2026	Procure or construct resources resulting from RFP (if needed).
2025	Exit Valmy Unit 2 by December 31, 2025.
2026	Subject to coordination with PacifiCorp, exit Jim Bridger unit (as yet undesignated) by December 31, 2026. Timing of the exit from the second Jim Bridger unit is tied to the need for a resource addition (B2H).

* These items were complete at the time the Amended IRP was filed.

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 (ISEA) was established to help develop effective and long-lasting responses to existing and future energy challenges. The purpose of the ISEA is to enable the development of a sound energy portfolio that emphasizes the importance of an affordable, reliable, and secure energy supply.

The ISEA strategy to accomplish this purpose rests on three foundational elements: 1) maintaining and enhancing a stable, secure, and affordable energy system; 2) determining how to maximize the economic value of Idaho's energy systems and in-state capabilities, including attracting jobs and energy-related industries, and creating new businesses with the potential to serve local, regional, and global markets; and 3) educating Idahoans to increase their knowledge about energy and energy issues.

Idaho Power representatives serve on the ISEA Board of Directors and several volunteer task forces on the following topics:

- Energy efficiency and conservation
- Wind
- Geothermal
- Hydropower
- Baseload resources
- Biogas
- Biofuel
- Solar
- Transmission
- Communication and outreach
- Energy storage
- Transportation

Idaho Energy Landscape

In 2019, the ISEA prepared the *2019 Idaho Energy Landscape Report*. The 2019 report is a resource to help Idahoans better understand the contemporary energy landscape in the state and to make informed decisions about Idaho's energy future.

The *2019 Idaho Energy Landscape Report* concludes the health of Idaho's economy and quality of life depend on access to affordable and reliable energy resources. The report provides information about energy resources, production, distribution, and use in the state. The report also discusses the need for reliable, affordable, and sustainable energy for individuals, families, and businesses while protecting the environment to achieve sustainable economic growth and maintain Idaho's quality of life.

The 2019 report finds a weakening correlation between economic growth and energy consumption due to technological changes and the increased use of energy efficiency. Idaho's gross domestic product grew 4.7 percent annually from 1997 to 2017, yet Idaho's energy consumption (transportation, heat, light, and power) grew just 1.1 percent annually from 1990 to 2016.

Despite the modest growth in energy consumption, Idaho continues to be a net importer of energy, which requires a robust and well-maintained infrastructure of highways, railroads, pipelines, and transmission lines. Based on Idaho's 2016 electricity energy sources, approximately 32 percent was comprised of market purchases and energy imports from out-of-state generating resources owned by Idaho utilities.

The report states that low average rates for electricity and natural gas are the most important feature of Idaho's energy outlook. Large hydroelectric facilities on the Snake River and other tributaries of the Columbia River provide energy and flexibility required to meet the demands of this growing region. Based on 2017 data, hydroelectricity and coal are the two largest sources of Idaho's electricity, comprising 53 and 17 percent, respectively. Natural gas makes up 14 percent, and non-hydro renewables, principally wind power, solar, geothermal, and biomass, account for approximately 14 percent. Idaho's electricity rates were the fifth lowest among the 50 states in 2017.

State of Oregon 2018 Biennial Energy Report

In 2017, the Oregon Department of Energy (ODOE) introduced House Bill (HB) 2343, which charges the ODOE to develop a new biennial report to inform local, state, regional, and federal energy policy development and energy planning and investments. The inaugural 2018 biennial report provides foundational energy data about Oregon and examines the existing policy landscape while identifying several options for continued progress toward meeting the state's goals in the areas of climate change, renewable energy, transportation, energy resilience, energy efficiency, and consumer protection.

The biennial report shows an evolving energy supply in Oregon. While Oregon's 2017 energy supply consisted primarily of hydroelectric power, coal, and natural gas, renewable energy continues to make up an increasing share of the energy mix each year. Wind energy consumed in Oregon increased 741 percent between 2004 and 2016, and solar generation increased from 28 MWh in 2008 to 266,000 MWh in 2016. With the increase in renewable energy sources, other resources in the electricity mix have changed as well. The amount of coal included in Oregon's resource mix has dropped since 2005. Natural gas, a resource that can help to integrate variable renewable resources, like wind and solar, into the grid has increased from 12.1 percent in 2012 to 18.4 percent in 2016.

The main theme of the 2018 biennial report was Oregon's transition to a low-carbon economy. According to the report, achieving Oregon's energy and climate goals, while protecting consumers, will take collaboration among state agencies, policy makers, state and local governments, and private-sector business and industry leaders.

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.

Hells Canyon Dam

Idaho Power's remaining and most significant ongoing relicensing effort is for the Hells Canyon Complex (HCC). The HCC provides approximately 68 percent of Idaho Power's hydroelectric generating capacity and 32 percent of the company's total generating capacity. The original 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 provides clean energy to Idaho Power's system, supporting Idaho Power's long-term clean energy goals. The HCC also provides flexible capacity critical to the successful integration of VER, further enabling the achievement of Idaho Power's clean energy goals.

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. Since issuance of the final environmental impact statement (EIS) (NEPA document) in 2007, FERC has been waiting for Idaho and Oregon to issue a final Section 401 certification under the CWA. The states issued the final CWA 401 certification, subject to appeal, on May 24, 2019. FERC will now be able to continue with the relicensing process, which includes consultation under the ESA, among other actions.

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 2022. In December 2017, Idaho Power filed with the IPUC a settlement stipulation signed by Idaho Power, IPUC staff, and a third-party intervenor recognizing a total of $216.5 million in expenditures had been reasonably incurred through year-end 2015, and therefore, should be eligible for inclusion in customer rates at a later date. The IPUC approved the settlement in April 2018 (IPUC Order No. 34031).

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 protection, mitigation, and enhancement (PM&E) packages are still being conducted, Idaho Power cannot determine the ultimate terms of, and costs associated with, any resulting long-term license.

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. As noted earlier, Idaho Power views the relicensing of the HCC as critical to its clean energy goals.

No reduction of the available capacity or operational flexibility of the hydroelectric plants to be relicensed has been assumed in the 2019 IRP.

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. Idaho Power is dedicated to the vigorous defense of its water rights. Idaho Power's ongoing participation in water-right issues and ongoing studies is 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. Because of the SRBA, Idaho Power'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 Hydroelectric Project (Swan

Falls Project). The agreement stated Idaho Power's water rights at its hydroelectric facilities between Milner Dam and Swan Falls entitled Idaho Power 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 Idahoans. 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 because 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 Idaho Power'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 recognizes water-management measures that enhance aquifer levels, springs, and river flows—such as managed aquifer-recharge projects—to benefit 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 program, along with forecasting and meteorological data support. 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 the delivery of water to its members at the Minidoka and Milner dams. 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- 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.

Variable Energy Resource Integration

Since the mid-2000s, Idaho Power has completed multiple studies investigating the impacts and costs associated with integrating VERs, such as wind and solar, without compromising reliability. Idaho Power's most recent VER study was completed in 2018. As suggested by feedback from the 2017 IRP, as well as the results of Idaho Power's *2018 Variable Energy Resource Integration Analysis* (2018 VER Study), several improvements were incorporated into AURORA and the resource portfolio analysis of the 2019 IRP to model the adequate maintenance of reserve margins as resources are added or removed in the IRP portfolios.

In compliance with Order Nos. 17-075 and 17-223 in Oregon Docket No. UM 1793, Idaho Power filed the 2018 VER Study, which described the methods followed by Idaho Power to estimate the amounts of regulating reserves necessary to integrate VER without compromising system reliability. The methods followed in the 2018 VER Study (which were developed in collaboration with the study's technical review committee, including personnel from both the Idaho and Oregon PUCs) yielded estimated regulating reserve requirements necessary to balance the netted system of load, wind, and solar (net load). The 2018 VER Study expressed these regulating reserve requirements as the dynamically varying function of several factors:

- Season (spring, summer, fall, winter)
- Load-base schedule (two-hour ahead schedule)
- Time of day (for load)
- Wind-base schedule
- Solar-base schedule

The regulating reserve requirements necessary to balance net load for a given hour can be expressed as dependent on the above five factors. The derivation of the regulating reserve requirements from a net-load perspective captures the tendency of the three elements (i.e., load, wind, and solar) to deviate from their respective base schedules in an offsetting manner.

Therefore, the amount of regulating reserve required for net load is less than the sum of the individual requirements for each element.

The 2018 VER Study suggested a unified VER integration analysis may be a favored approach for assessing impacts and costs for incremental wind and solar additions going forward. The 2018 VER Study also notes that Idaho Power's system is nearing a point where the current system of reserve-providing resources (i.e., dispatchable thermal and hydro resources) can no longer integrate additional VERs without taking additional action to address potential reserve requirement shortfalls. The 2018 VER Study concluded that additional investigation is warranted into the combined effect of wind and solar, in a unified VER integration cost analysis, along with the effects of Energy Imbalance Market (EIM) participation.

The 2018 VER Study also identified that, based on the current resources on Idaho Power's system, 173 MW of additional VERs could be integrated before reserve margin violations exceed 10 percent of the operating hours during the year. The study also concluded that at the high relative penetration levels of variable wind and solar that currently exist on Idaho Power's system, additional analysis is warranted, and as Idaho Power gains more experience operating as part of the EIM.

AURORA modeling used in the 2019 IRP has improved since the 2018 VER Study. The 2019 IRP uses the AURORA model Version 13.2.1001, which incorporates improvements in modeling reserve requirements combined with Idaho Power's own modeling improvements and assumptions. Specifically, the HCC hydro units can use the hydro logic in AURORA, which allows for spill. The resources dedicated to maintaining the additional reserves incur costs, such as spill, which are captured within the model as increased cost to the portfolio. The model version enhancements allow Idaho Power to include all 12 HCC hydro units as providing reserves in the 2019 IRP LTCE process, which mirrors a more realistic HCC hydro operation. The existing thermal units' ability to provide reserves is nearly identical to the previous setup. The evolution of using the enhanced capabilities in AURORA to define the resource portfolios using the LTCE logic while simultaneously incorporating the VER dynamic reserve rules associated with varying quantities of VERs is a significant advancement in portfolio design at Idaho Power.

For the 2019 IRP, integration charges for VERs are not used as an input into the AURORA model because portfolio development for the 2019 IRP is being performed through LTCE modeling. Under this approach, the model's selection of resources is driven by the objective to construct portfolios that are low cost and achieve the planning margin and regulating reserve requirements. Based on approximations of the 2018 VER Study's dynamically defined regulating reserve requirements, the 2019 IRP includes hourly regulating reserves associated with current levels of load, wind, and solar, as well as future portfolios having higher levels of load and potentially higher levels of VERs.

For the 2019 IRP analysis, the 2018 VER Study provided the rules to define hourly reserves needed to reliably operate the system based on current and future quantities of solar and wind generation and load forecasted by season and time of day. Improvements in Version 13 of the

AURORA model, compared to when the study was performed,[4] allow the 2018 VER Study reserve rules to dynamically establish hourly reserves for different quantities of variable resources in a portfolio. The reserves are defined separately, incorporating their combined diversity benefits dynamically in the modeling. The reserve rules applied in the 2019 IRP include defining hourly reserve requirements for "Load Up," "Load Down," "Solar Up," "Solar Down," and "Wind Up." The "Wind Down" reserves are included in the "Load Down" reserves, as AURORA cannot dynamically apply the "Wind Down" reserves rules as defined and applied in the study.

The 2019 IRP analysis is a step toward a unified VER integration cost analysis as concluded in the 2018 VER Study. While the 2018 VER study provided valuable information regarding the rules for reserve requirements, the modeling performed for the 2019 IRP provides more information on how VERs affect Idaho Power's system and the ability to maintain sufficient reserves. The 2019 IRP has allowed Idaho Power, via the AURORA model, to quantitatively capture and enforce the hourly flexibility requirements for a portfolio to dynamically change regulating reserves in line with the 2018 VER Study reserve requirement rules.

The results of the 2019 IRP portfolio development show that additional VERs are selected in a majority of LTCE portfolios, and many of the portfolios show new solar resources selected and coal units being retired. This indicates the model has sufficient regulating reserves to economically retire a reserve-contributing coal unit while adding new solar resources.

Additionally, Idaho Power's load is forecast to grow through 2022 and 2023, which allows more VERs to be successfully integrated. The additional VERs in the AURORA integrated portfolio analysis dynamically increase the system reserves associated with increased VER energy by applying the 2018 VER Study rules to model reliable system operations. However, when additional incremental VERs are added to the system outside, or between, IRP cycles, there is still a need to identify the incremental cost of maintaining adequate reserves for reliable operations. This will require Idaho Power to continue to build on the advancements made by the 2019 IRP analysis of a unified VER integration cost first identified in the 2018 VER Study. As noted in the near-term action plan, this will be performed in conjunction with the additional experience the company gains from continued operation in the EIM, as well as with the collaboration of a Technical Review Committee as part of an updated integration study.

Community Solar Pilot Program

Idaho

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, Idaho Power proposed to build and own a 500-kilowatt (kW) single-axis tracking community solar array in southeast Boise and allow a limited number of Idaho Power's Idaho customers to voluntarily subscribe to the generation output on a first-come basis.

[4] The 2018 VER Study was performed using Version 12.1.1046 of the AURORA model.

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 Idaho Power'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 nonparticipating customers.

The IPUC approved the pilot program on October 31, 2016, and marketing efforts for customer subscriptions began immediately.

Due to insufficient program enrollment, in February 2019, Idaho Power filed with the IPUC to suspend Schedule 63, Community Solar Pilot Program. The IPUC opened Case No. IPC-E-19-05 to process the request, and on April 26, 2019, issued Order No. 34317 approving the company's request to suspend Schedule 63. Idaho Power will continue to work with stakeholders to determine a community solar program design that could be successful in a future offering.

Oregon

In 2016, the Oregon Legislature enacted Senate Bill (SB) 1547, which requires the OPUC to establish a program for the procurement of electricity from community solar projects. Community solar projects provide electric company customers the opportunity to share in the costs and benefits associated with the electricity generated by solar photovoltaic systems, as owners of or subscribers to a portion of the solar project.

Since 2016, the OPUC has conducted an inclusive implementation process to carefully design and execute a program that will operate successfully, expand opportunities, and have a fair and positive impact across electric company ratepayers. After an inclusive stakeholder process, the OPUC adopted formal rules for the CSP on June 29, 2017, through Order No. 17-232, which adopted Division 88 of Chapter 860 of the Oregon Administrative Rules. The rules also define the program size, community solar project requirements, program participant requirements, and details surrounding the opportunity for low-income participants, as well as information regarding on-bill crediting.

Under the Oregon Community Solar Program rules, Idaho Power's initial capacity tier is 3.3 MW. As of the date of this filing, Idaho Power has completed the interconnection study process for a 2.95 MW project that intends to participate in the community solar program. The company believes that the project is well positioned to obtain the necessary certifications to participate in the community solar program. The proposed 2.95 MW project will use all but 305 kW of Idaho Power's initial capacity allocation.

Renewable Energy Certificates

A REC, also known as a green tag, represent the green or renewable attributes of energy produced by a certified renewable resources. Specifically, 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 produced by a certified renewable resource can either be sold together with the energy (bundled), sold separately (unbundled), or be retired to comply with a state- or federal-level renewable portfolio standard (RPS). An RPS is a policy requiring a minimum amount (usually a percentage) of the electricity each utility delivers to customers to come from renewable energy resources. 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 associated with the REC (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 each state's power cost adjustment (PCA) mechanisms 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 of the participant funds are used to purchase RECs 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 2018, Idaho Power purchased and subsequently retired 18,148 RECs on behalf of Green Power participants. In 2018, all Green Power RECs were sourced from projects located in Idaho.

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 2017, per U.S. Energy Information Administration (EIA) data, Idaho Power's Oregon customers represented 1.4 percent of Oregon's total retail electric sales. As a smaller utility in the state of Oregon, Idaho Power will likely have to meet a 5-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.

Carbon Adder/Clean Power Plan

In June 2014, the Environmental Protection Agency (EPA) released, under Section 111(d) of the *Clean Air Act of 1970* (CAA), a proposed rule for addressing greenhouse gas (GHG) from existing fossil fuel-fired electric generating units (EGU). The proposed rule was intended to achieve a 30-percent reduction in CO_2 emissions from the power sector by 2030. In August 2015, the EPA released the final rule under Section 111(d) of the CAA, referred to as the Clean Power Plan (CPP), which required states to adopt plans to collectively reduce 2005 levels of power sector CO_2 emissions by 32 percent by 2030.

The final rule provided states until September 2018 to submit implementation plans, phasing in several compliance periods beginning in 2022 and achieving the final emissions goals by 2030. In August 2018, the EPA proposed the Affordable Clean Energy (ACE) rule to replace the CPP under Section 111(d) of the CAA for existing electric utility generating units.

The new proposed rule is limited to reduction and compliance measures occurring at the physical location of each plant, removing the proposal to require reductions outside the boundaries of plants. The Affordable Clean Energy (ACE) rule also provides for more state-specific control over implementation of the rule to address GHG emissions from existing coal-fired power plants, with a focus on state evaluation of improvement potential, technical feasibility, applicability, and remaining useful life of each unit.

Because the rule is premised on state implementation plans, the terms of which Idaho Power does not control, and due to the existing and potential changes in legislation, regulation, and government policy with respect to environmental matters as a result of the presidential administration's executive orders and the EPA's proposal to repeal and replace the CPP, as of the date of this report and in light of these executive actions, Idaho Power is uncertain whether and to what extent the replacement CPP may impact its operations in the near future. For the 2019 IRP, Idaho Power assumes a carbon adder to account for costs associated with CO_2 emissions. The analyzed carbon cost forecasts are discussed in Chapter 8.

3. Idaho Power Today

Customer Load and Growth

In 1994, Idaho Power served approximately 329,000 general business customers. Today, Idaho Power serves more than 560,000 general business customers in Idaho and Oregon. Firm peak-hour load has increased from 2,245 MW in 1994 to about 3,400 MW. On July 7, 2017, the peak-hour load reached 3,422 MW—the system peak-hour record.

Residential construction growth in southern Idaho.

Average firm load increased from 1,375 average MW (aMW) in 1994 to 1,801 aMW in 2018 (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 5.0 kW to the peak-hour load and over 3.0 average kW (akW) to the average load.

Since 1994, Idaho Power's total nameplate generation has increased from 2,661 MW to 3,594 MW. Table 3.1 shows Idaho Power's changes in reported nameplate capacity since 1994. Additionally, Idaho Power has added about 228,000 new customers since 1994.

Idaho Power anticipates adding approximately 10,900 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 nearly 50 MW per year, and the average-energy requirement is forecast to grow over 20 aMW per year. More detailed customer and load forecast information is presented in Chapter 7 and in *Appendix A—Sales and Load Forecast*.

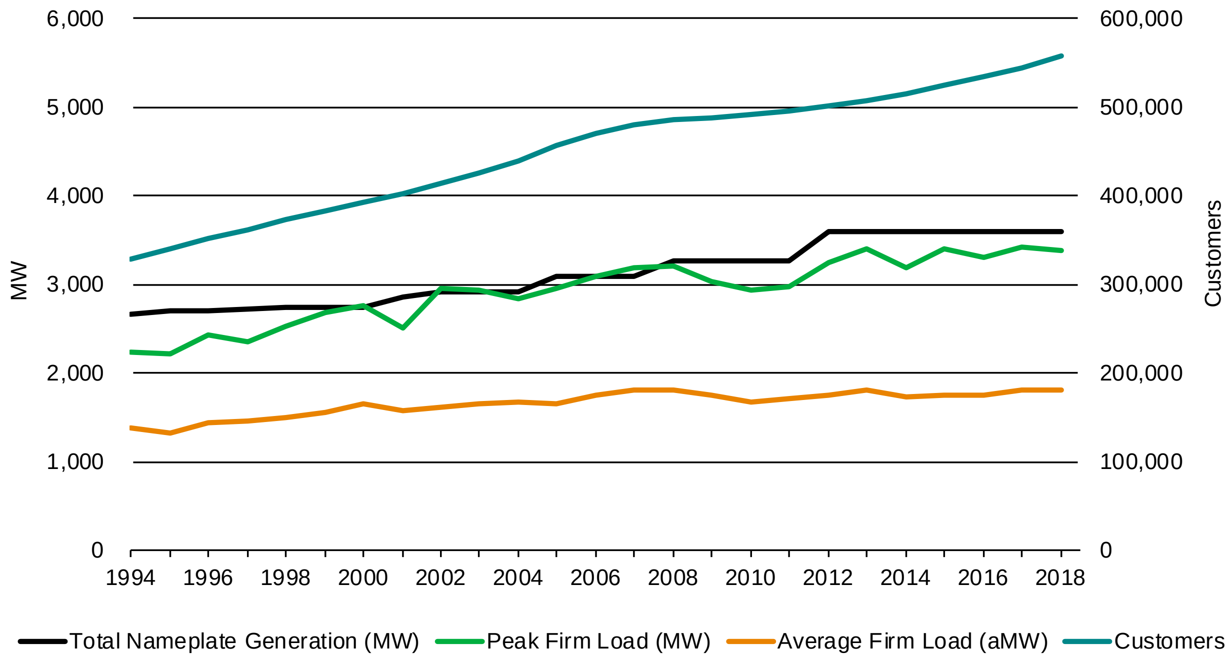

Figure 3.1 Historical capacity, load, and customer data

Table 3.1 Historical capacity, load and customer data

Year	Total Nameplate Generation (MW)	Peak Firm Load (MW)	Average Firm Load (aMW)	Customers[1]
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

Year	Total Nameplate Generation (MW)	Peak Firm Load (MW)	Average Firm Load (aMW)	Customers[1]
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	533,935
2017	3,594	3,422	1,807	544,378
2018	3,659[2]	3,392	1,810	556,926

1 Year-end residential, commercial, and industrial customers, plus the maximum number of active irrigation customers.
2 Reported nameplate capacity reflects recent modifications to hydroelectric facilities.

2018 Energy Sources

Idaho Power's energy sources for 2018 are shown in Figure 3.2. Idaho Power-owned generating capacity was the source for 71.4 percent of the energy delivered to customers. Hydroelectric production from company-owned projects was the largest single source of energy at 46.4 percent of the total. Coal contributed 17.5 percent, and natural gas- and diesel-fired generation contributed 7.5 percent. Purchased power comprised 28.6 percent of the total energy delivered to customers. Of the purchased power, 9.3 percent of the total delivered energy was from the wholesale electric market. The remaining purchased power, 19.3 percent, was from long-term energy contracts (*Public Utility Regulatory Policies Act of 1978* [PURPA] and PPAs) primarily from wind, solar, hydro, geothermal, and biomass projects (in order of decreasing percentage). While Idaho Power receives production from PURPA and PPA projects, the company sells the RECs it receives associated with the production and does not represent the energy from these projects as energy delivered to customers.

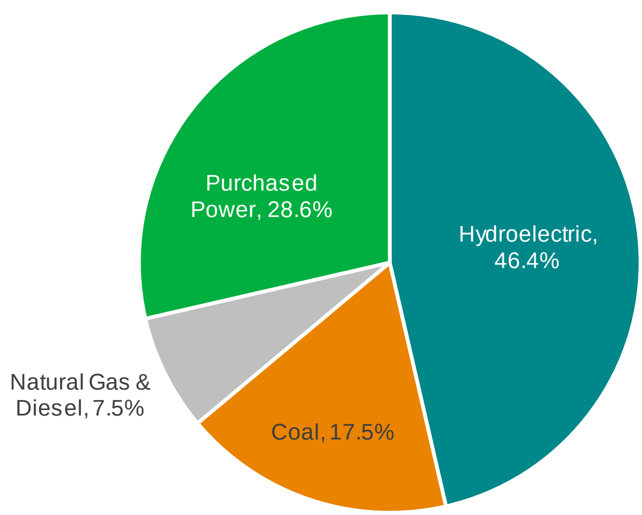

Figure 3.2 2018 energy sources

Existing Supply-Side Resources

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	652.6	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	11.5	Upper Snake
Swan Falls	Hydroelectric	27.2	Mid-Snake
Thousand Springs	Hydroelectric	6.8	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		**3,658.6**	

The following sections describe Idaho Power's existing supply-side 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 1,773 MW and annual generation equal to approximately 1,000 aMW, or 8.7 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 risk management, recreation, and the benefit of fish and wildlife resources.

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

After flood risk management 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 operationally stable flows below Hells Canyon Dam in the fall because of the Fall Chinook Program adopted by Idaho Power in 1991. The stable 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 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 standing water lease agreements. However, single year leases from the Upper Snake Basin are occasionally available, and the company 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 collaborate with the IWRB and water users in the upper Snake, Boise, and Wood river basins to expand the target area to include those watersheds.

Cloud seeding ground generators

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 releasing AgI 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 downwind.

AgI particles are very efficient ice nuclei, allowing minute quantities to have an appreciable increase in precipitation. It has been used as a seeding agent in numerous western states for decades without any known harmful effects.[5] Analyses conducted by Idaho Power since 2003 indicate the annual snowpack in the Payette River Basin increased between 1 and 22 percent annually, with an annual average of 11.3 percent. Idaho Power estimates cloud seeding provides an additional 424,000 acre-feet in the upper Snake River, 113,000 acre-feet in the Wood River Basin, 229,000 acre-feet in the Boise Basin, and 212,000 acre-feet from the Payette River Basin. At program build-out (including additional aircraft and remote ground generators), Idaho Power estimates additional runoff from the Payette, Boise, Wood, and Upper Snake projects will total approximately 1,269,000 acre-feet. The additional water from cloud seeding fuels the hydropower system along the Snake River.

Seeded and Natural Orographic Wintertime Clouds: the Idaho Experiment (SNOWIE) was a joint project between National Science Foundation and Idaho Power. Researchers from the Universities of Wyoming, Colorado, and Illinois used Idaho Power's operational cloud seeding project, meteorological tools, and equipment to identify changes within wintertime precipitation

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[5] weathermod.org/wp-content/uploads/2018/03/EnvironmentalImpact.pdf

Footnotes continued on the next page.

after seeding has taken place. Ground breaking discoveries continue to be evaluated from this dataset collected in winter 2017. Multiple scientific publications have already been published,[6] with more planned for submission about the effects and benefits of cloud seeding.

For the 2018 to 2019 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 32 remote controlled, ground-based generators and two aircraft for Idaho Power-operated cloud seeding in the 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 2018 to 2019 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. For the 2019 IRP, Idaho Power used the AURORA model's capacity expansion capability to evaluate a range of exit dates for the company's participation in the Jim Bridger units, where the evaluated exit dates were determined by the model within feasibility guidelines.

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. For the AURORA-based capacity expansion modeling performed for the 2019 IRP, Idaho Power assumes an exit from Unit 1 participation at year-end 2019 and from Unit 2 participation no later than year-end 2025. Pre-2025 exit from Unit 2 was an option selectable by the AURORA model; however, the model did not select pre-2025 exit for any portfolios.

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. Portland General Electric has 90 percent ownership and is the operator of the Boardman facility.

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[6] French, J. R., and Coauthors, 2018: Precipitation formation from orographic cloud seeding. Proc. Natl. Acad. Sci. USA, 115, 1168–1173, doi.org/10.1073/pnas.1716995115.

Tessendorf, S.A., and Coauthors, 2019: Transformational approach to winter orographic weather modification research: The SNOWIE Project. *Bull. Amer. Meteor. Soc.*, 100, 71–92, journals.ametsoc.org/doi/full/10.1175/BAMS-D-17-0152.1.

The 2019 IRP assumes Idaho Power's share of the Boardman plant will not be available after December 31, 2020. 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, requires the Boardman facility to cease coal-fired operations by year-end 2020.

Natural Gas Facilities and Salmon Diesel

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.

Danskin

The Danskin facility is located northwest of Mountain Home, Idaho. Idaho Power owns and operates one 179-MW Siemens 501F and two 46-MW Siemens–Westinghouse W251B12A combustion turbines at the facility. The two smaller turbines were installed in 2001, and the larger turbine was installed in 2008. Idaho Power is currently evaluating options to repower the two smaller Danskin turbines to improve efficiency and start capability, expand dispatch flexibility, and lower emissions. 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 Simple-Cycle Combustion Turbine (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.

Solar End-of-Feeder Project

Solar installation as part of the Solar End-of-Feeder Project.

The Solar End-of-Feeder Pilot Project is a small-scale (18 kW_{AC}) proof-of-concept PV system evaluated as a non-wires alternative to traditional methods to mitigate low voltage near the end of a distribution feeder. The purpose of the pilot was to evaluate its operational performance and its cost-effectiveness compared to traditional low-voltage mitigation methods. Traditional methods for mitigating low voltage include the addition of capacitor banks, voltage regulators, or reconductoring. Capacitor banks and voltage regulators are relatively inexpensive solutions compared to reconductoring, but these solutions were not viable options for this location due to distribution feeder topology.

The Solar End-of-Feeder Project was installed and has been in operation since October 2016. The project has operated as expected through the first two years of operation by effectively mitigating low voltage. The Solar End-of-Feeder Pilot Project is considered complete and will be monitored internally in the following years.

Customer Generation Service

Idaho Power's on-site generation and net metering services allow customers to generate power on their property and connect to Idaho Power's system. For participating customers, the energy generated is first consumed on the property itself, while excess energy flows out to the company's grid. Most customers use solar PV systems. As of March 31, 2019, there were 3,595 solar PV systems interconnected through the company's customer generation tariffs with a total capacity of 30.356 MW. At that time, the company had received completed applications for an additional 436 solar PV systems, representing an incremental capacity of 7.213 MW. For further details regarding customer-owned generation resources interconnected through the company's on-site generation and net metering services, see tables 3.3 and 3.4.

Table 3.3 Customer generation service customer count as of March 31, 2019

Resource Type	Active	Pending	Total
Idaho Total	3,589	429	4,018
Solar PV	3,541	428	3,969
Wind	38	0	38
Other/hydroelectric	10	1	11
Oregon Total	55	8	63
Solar PV	54	8	62
Wind	1	0	1
Other/hydroelectric	0	0	0
Total	**3,644**	**437**	**4,081**

Table 3.4 Customer generation service generation capacity (MW) as of March 31, 2019

Resource Type	Active	Pending	Total
Idaho Total	29.533	7.125	36.658
Solar PV	29.189	7.113	36.302
Wind	0.198	0.000	0.198
Other/hydroelectric	0.146	0.012	0.158
Oregon Total	1.170	0.100	1.270
Solar PV	1.167	0.100	1.267
Wind	0.002	0.000	0.002
Other/hydroelectric	0.000	0.000	0.000
Total	**30.703**	**7.225**	**37.928**

Oregon Solar Program

In 2009, the Oregon Legislature passed Oregon Revised Statute (ORS) 757.365 as amended by HB 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 PV 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 HB 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.

Public Utility Regulatory Policies Act

In 1978, the US congress passed PURPA, requiring investor-owned electric utilities to purchase energy from any qualifying facility (QF) that delivers energy to the utility. A QF is defined by FERC as a small renewable-generation project or small cogeneration project. Cogeneration and small power producers (CSPP) is often associated 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, 2019, Idaho Power had 133 PURPA contracts with independent developers for approximately 1,148 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, 127 were on-line as of April 1, 2019, with a cumulative nameplate rating of approximately 1,119 MW. Figure 3.3 shows the percentage of the total PURPA nameplate capacity of each resource type under contract.

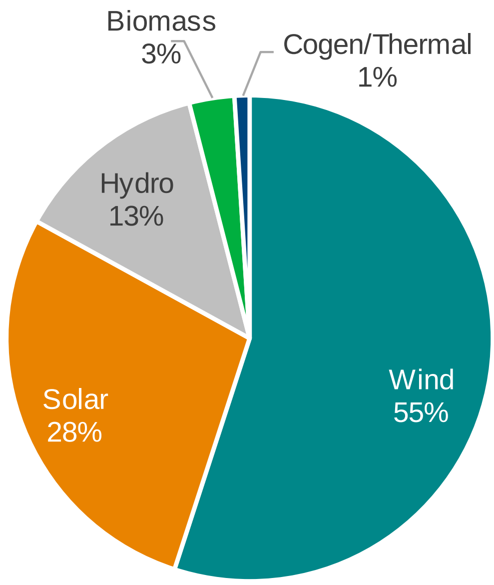


Figure 3.3 PURPA contracts by resource type

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 accounting of supply-side resources available to meet load. The PURPA forecast used in the 2019 IRP was completed in October 2018. Detail on signed PURPA contracts, including capacity and contractual delivery dates, is included in *Appendix C—Technical Appendix*.

Power Purchase Agreements

Elkhorn Wind

In February 2007, the IPUC approved a PPA with Telocaset Wind Power Partners, LLC, for 101 MW of nameplate wind generation from the Elkhorn Wind Project located in northeastern Oregon. The Elkhorn Wind Project was constructed during 2007 and began commercial operations in December 2007. Under the PPA, Idaho Power receives all the RECs from the project. Idaho Power's contract with Telocaset Wind Power Partners, LLC, expires December 2027.

Raft River Unit 1

In January 2008, the IPUC approved a PPA with Raft River Energy I, LLC, for approximately 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. Idaho Power is entitled to 51 percent of all RECs generated by the project for the remaining term of the agreement. Idaho Power's contract with Raft River Energy I, LLC, expires April 2033.

Neal Hot Springs

In May 2010, the IPUC approved a PPA with USG Oregon, LLC, for approximately 22 MW of nameplate generation from the Neal Hot Springs Unit 1 geothermal project located in eastern Oregon. The Neal Hot Springs Unit 1 project achieved commercial operation in November 2012. Under the PPA, Idaho Power receives all RECs from the project. Idaho Power's contract with USG Oregon, LLC expires November 2037.

Jackpot Solar

On March 22, 2019, Idaho Power and Jackpot Holdings, LLC entered a 20-year PPA for the purchase and sale of 120 MW of solar electric generation from the Jackpot Solar facility located north of the Idaho–Nevada state line near Rogerson, Idaho. Under the terms of the PPA, Idaho Power will receive all RECs from the project. Jackpot Solar is scheduled to be on-line December 2022.

An application was submitted to the IPUC on April 4, 2019, requesting an order that approves the PPA and on December 24, 2019, the IPUC issued Order No. 34515 approving the Jackpot Solar PPA. On the same day as the IPUC application, Idaho Power submitted a notice to the OPUC, in accordance with OAR 860-089-100(3) and (4), of an exception from Oregon's competitive-bidding requirements for electric utilities as the PPA with Jackpot Holdings, LLC presents a time-limited opportunity to acquire a resource of unique value to Idaho Power customers. On December 24, 2019, the IPUC issued Order No. 34515 approving the PPA with Jackpot Holdings, LLC.

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).

Idaho Power's interconnected transmission facilities were all jointly developed with other entities and act to meet the needs of the interconnecting participants. Idaho Power owns various amounts of capacity across each transmission path; the paths and their associated capacity are further described in Chapter 6. Idaho Power reserves portions of its transmission capacity to import energy for load service (network set-aside); this set-aside capacity along with existing contractual obligations consumes nearly all of Idaho Power's import capacity on all paths (see Table 6.1 in Chapter 6).

4. Future Supply-Side Generation and Storage Resources

Generation Resources

Supply-side generation resources include traditional generation resources, renewable resources, and storage resources. Idaho Power gives equal treatment to both supply-side and demand-side resources. As discussed in Chapter 5, demand-side programs are an essential and valuable component of Idaho Power's resource strategy. The following sections describe the supply-side resources and energy-storage technologies considered when Idaho Power developed and analyzed the resource portfolios for the 2019 IRP. Not all supply-side resources described in this section were included in the modeling, but every resource described was considered.

The primary source of cost information for the 2019 IRP is the 2018 Annual Technology Baseline (ATB) report released by the National Renewable Energy Laboratory (NREL) in July 2018.[7] Other information sources were relied on or considered on a case-by-case basis depending on the credibility of the source and the recency of the information. For a full list of all the resources considered and cost information, refer to Chapter 7. All cost information presented are in nominal dollars with an on-line date of 2023 for all levelized cost of energy (LCOE) calculations. Provided levelized cost figures are based on Idaho Power's cost of capital and may differ from other reported levelized costs.

Renewable Resources

Renewable energy resources serve as the foundation of Idaho Power's existing portfolio. The company emphasizes a long and successful history of prudent renewable resource development and operation, particularly as related to its fleet of hydroelectric generators. In the 2019 IRP, a variety of renewable resources were included in many of the portfolios analyzed. Renewable resources are discussed in general terms in the following sections.

Solar

The primary types of solar generation technology are utility-scale photovoltaic (PV) and distributed PV. In general, PV technology absorbs solar energy collected from sunlight shining on panels of solar cells, and a percentage of the solar energy is absorbed into the semiconductor material. The energy accumulated inside the semiconductor material creates an electric current. The solar cells have one or more electric fields that force electrons to flow in one direction as a direct current (DC). The DC energy passes through an inverter, converting it to alternating current (AC) that can then be used on site or sent to the grid.

Solar 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) per day (daily insolation average over a year). The higher the insolation number, the better

[7] atb.nrel.gov/

the solar-power potential for an area. NREL insolation charts show the desert southwest has the highest solar potential in the continental US.

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, have made PV resources more cost competitive with other renewable and conventional generating technologies.

The capital-cost estimate used in the 2019 IRP for utility-scale PV resources is $1,334 per kW[8] for PV with a single-axis tracking system. The 30-year LCOE for PV with single-axis tracking is $67 per MWh assuming a 26-percent annual capacity factor.

Rooftop solar was considered in two forms as part of the 2019 IRP. The capital-cost estimate used for residential rooftop solar PV resources is $2,947 per kW for PV. The 25-year LCOE for residential rooftop solar PV resources is $180 per MWh assuming a 21-percent annual capacity factor. The capital-cost estimate used for commercial and industrial rooftop solar PV resources is $2,160 per kW. The 25-year LCOE for commercial and industrial rooftop solar PV resources is $133 per MWh assuming a 21-percent annual capacity factor. Rooftop solar is assumed to be fixed tilt and south facing.

In addition to generic locations for solar PV arrays, the 2019 IRP analyzed select areas that are reflective of a targeted siting for solar capacity within Idaho Power's service area. Targeted solar is a process of identifying select locations on the delivery system where a solar facility could defer growth or reliability investments on the distribution or transmission system. These select areas are limited in size at 0.5 MW, with a total of 10 MW for the 20-year planning period. The capital-cost estimate used in the 2019 IRP for a targeted siting for grid benefit PV resource is $1,734 per kW. The 30-year LCOE is $77 per MWh assuming a 26-percent annual capacity factor. See the Targeted Grid Solar section later in this chapter for further discussion.

Advancements in energy storage technologies have focused on coupling storage devices with solar PV resources to mitigate and offset the effects of an intermittent generation source. This coupling or pairing of resources was modeled and considered in the 2019 IRP. For a more complete description of battery storage, please refer to the Storage Resources section of this chapter.

The capital-cost estimate used in the 2019 IRP for a 40 MW single-axis tracking, utility-scale PV resources coupled with a 10 MW (40 MWh) lithium ion (Li) battery is $1,575 per kW. The LCOE is $90 per MWh assuming a 22-percent annual capacity factor for the entire facility. The levelized cost of energy assumes a 30-year economic life on the solar PV equipment and a 20-year economic life on the batteries with full battery-replacement costs incurred after year 10.

The capital-cost estimate used in the 2019 IRP for a 40 MW single-axis tracking, utility-scale PV resources coupled with a 20 MW (80 MWh) Li battery is $1,735 per kW. The LCOE is $120 per MWh assuming an 18-percent annual capacity factor for the entire facility. The LCOE assumes a

[8] Capital costs for solar PV expressed in terms of dollars per AC kW, assume DC:AC ratio of 1.3:1.

30-year economic life on the solar PV equipment and a 20-year economic life on the batteries with full battery-replacement costs incurred after year 10.

The capital-cost estimate used in the 2019 IRP for a 40 MW single-axis tracking, utility-scale PV resources coupled with a 30 MW (120 MWh) Li battery is $1,849 per kW. The LCOE is $152 per MWh assuming a 15-percent annual capacity factor for the entire facility. The LCOE assumes a 30-year economic life on the solar PV equipment and a 20-year economic life on the batteries with full battery-replacement costs incurred after year 10.

Solar-Capacity Value

For the 2019 IRP, Idaho Power updated the capacity value of solar using the 8,760-based method developed by NREL[9] and detailed herein. The NREL method is specifically described as a technique for representing VER capacity value in capacity expansion modeling, such as conducted using the AURORA model for the 2019 IRP. The capacity value of solar PV generation is a measurement of the contribution of solar PV capacity to meet system demand (including planning reserves). The capacity value of the solar PV is expressed as the percentage of nameplate AC capacity that contributes to the top peak net-load hours.

Capacity Value for Solar PV Methodology

The methodology employed by Idaho Power to calculate the capacity value for solar PV uses an Idaho Power system load-duration curve (LDC) and a net load-duration curve (NLDC), representing the net of system load and solar PV generation, for an entire year. The LDC reflects the total system load, sorted by hour, from the highest load to the lowest load. The NLDC represents the total system load minus the time-synchronized contribution from solar PV generation. The resulting net load is then sorted by hour, from the highest load to the lowest load.

As shown in Figure 4.1, the capacity value of existing solar PV generation is the difference in the areas between the LDC (System Load) and NLDC (Net Load) during the top 100 hours of the duration curves divided by the rated AC capacity of the solar PV generation installed. These 100 hours can be a proxy for the hours with the highest risk for loss of load.

$$Capacity\ Value\ (\%) = \frac{\sum_{1}^{100} LDC - \sum_{1}^{100} NLDC}{Solar\ PV_{rated}}$$

[9] nrel.gov/docs/fy17osti/68869.pdf

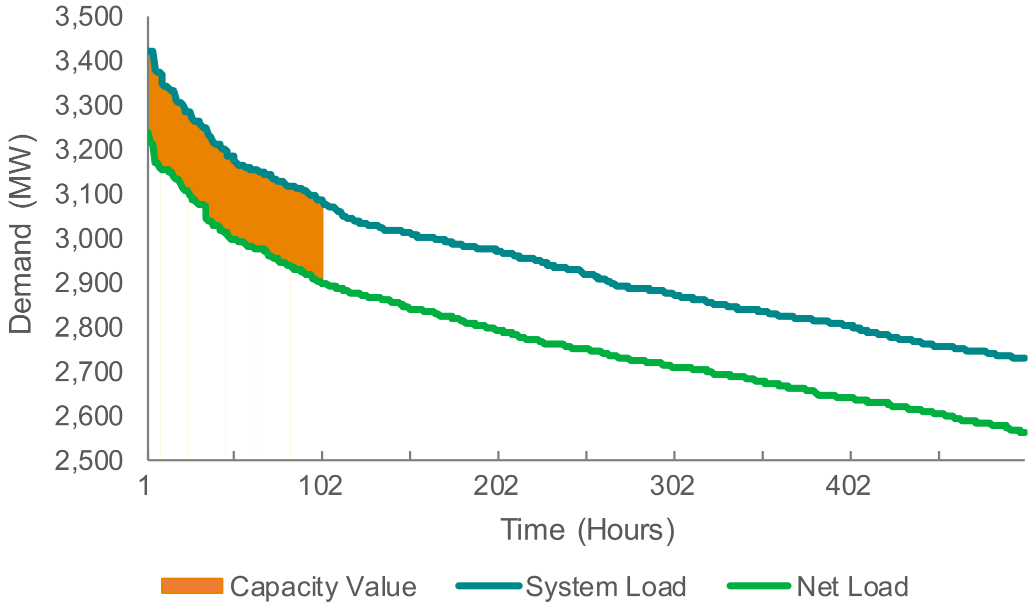


Figure 4.1 Capacity value of solar PV

In a similar fashion, the capacity value of the next solar PV plant, or the marginal capacity value (δ) of incremental solar PV, can be calculated using the same methodology. The marginal NLDC (δ) of incremental solar PV is calculated by subtracting the time-synchronized generation of incremental solar capacity from the NLDC. The resulting time series is again sorted by hour, from the highest load to the lowest load.

As shown in Figure 4.2, the marginal capacity value of incremental solar PV is the difference in the areas between the NLDC (net load) and the NLDC (δ) (Net load [δ]) divided by the rated AC incremental solar PV capacity.

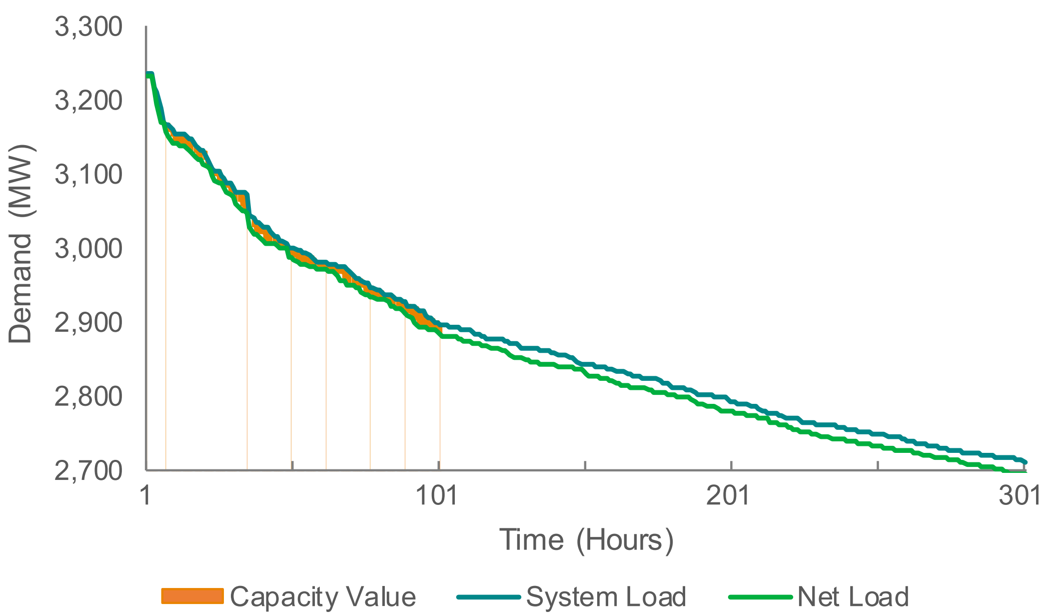


Figure 4.2 Marginal capacity value

Results

Capacity value was derived for three categories: 1) existing operational solar PV, 2) solar PV projects in construction, and 3) the future PV projects capacity value. The marginal capacity value of future PV projects was calculated in 40 MW alternating current (MWAC) increments.

The capacity value of the existing operational solar PV was first calculated by applying the method to the 2017 system load. The capacity value was also calculated using 2018 system load. The final capacity value was obtained by averaging the capacity value obtained for both years.

Table 4.1 shows the capacity value for the solar PV presently connected and for the solar PV projects in construction. The existing operational solar PV was evaluated as a single solar PV generator with 289.5 MWAC, representing the sum of the rated capacity of the existing operational solar PV generation on Idaho Power's systems as of June 2019.

The capacity value of the projects under construction was calculated as a single solar PV generator with a rated capacity of 26.5 MWAC, representing the rated capacity of the sum of the solar PV generation projects under construction.

Table 4.1 Summary of capacity value results

	Capacity Value (% of Nameplate Capacity)
Existing operational solar PV (289.5 MW)	61.86%
Projects under construction (26.5 MW)	47.92%

Idaho Power calculated the marginal capacity value of incremental solar PV projects each with a capacity rating of 40 MWAC. As the overall system peak load is decreased by the addition of incremental amounts of solar PV, eventually the top 100 hours of peak load contain fewer and fewer hours when solar PV may contribute to reducing the peak load. Therefore, the incremental capacity value of solar decreases as more solar is added to the system. Figure 4.3 shows the resulting capacity value for every 40 MWAC increment of solar PV.

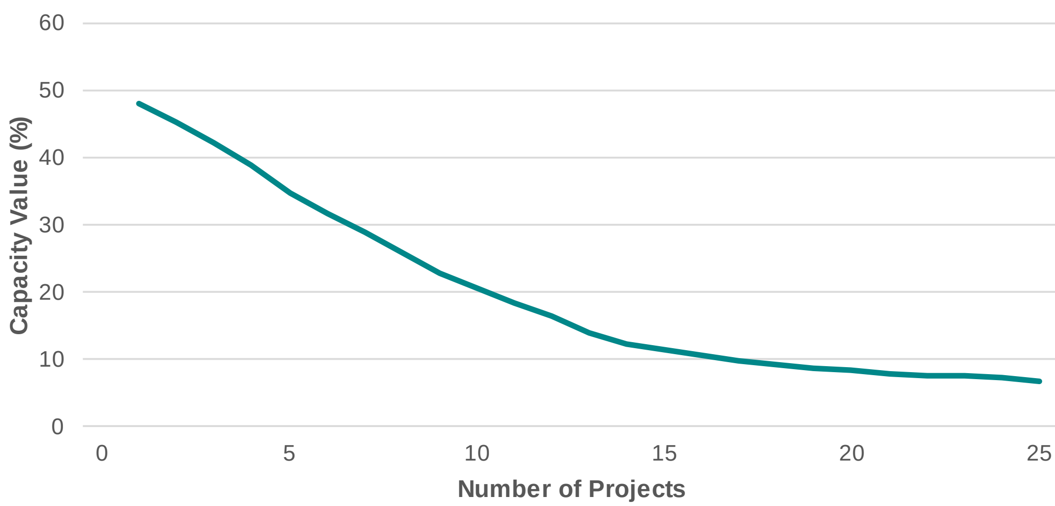


Figure 4.3 Capacity value of incremental solar PV projects (40 MW each)

Targeted Grid Solar

Idaho Power analyzed transmission and distribution (T&D) deferral benefits associated with targeted solar. The analysis included the following:

1. **Deferrable Investments**: Potentially deferrable infrastructure investments were identified spanning a 20-year period from 2002 through 2021. The infrastructure investments served as a test bed to identify the attributes of investments required to serve Idaho Power's growing customer base and whether those investments could have been (or could be) deferred with solar. Transmission, substation, and distribution projects driven by capacity growth were analyzed. The limiting capacity was identified for each asset along with the recommended in-service date, projected cost, peak loading, peak time of day, and projected growth rate.
2. **Solar Contribution**: The capacity demand reduction from varying amounts of solar was analyzed. Irradiance data was assumed to be consistent throughout the service area. The following was assumed for solar projects:
    - Rooftop solar: fixed, south facing
    - Large-scale solar: single-axis tracking
3. **Methodology**: If the net forecast (electrical demand minus an assumed solar generation contribution) was below the facility limiting capacity, the project could have been (or could be) deferred. The financial savings of deferring the project were then calculated.

Idaho Power selected five infrastructure investments from the data set that could have been deferred with varying amounts of solar. The selection was made to represent different areas, solar project sizes, and deferral periods, as well as the frequency at which projects are likely to be deferrable on Idaho Power's system. The solar generation required to achieve each deferral and the value of each deferral varied.

Table 4.2 Solar capacity required to defer infrastructure investments

Location	Years Deferred	Deferral Savings	Solar Project Size (kW)	Capacity Value ($/kW)
Blackfoot	8	$79,550	964	$82.52
Siphon (Pocatello)	4	$107,789	4,472	$24.10
Wye (Boise)	3	$19,767	2,339	$8.45
Nampa	2	$66,516	1,516	$43.87
Dietrich	2	$16,965	229	$74.08

The average capacity value of the identified investments was $46.60 per kW. This value was used for the T&D deferral locational value and reflected in Targeted Solar.

It is anticipated that a locational value of T&D deferral may apply to an annual average of 500 kW of solar over the 20-year IRP forecast for a total potential of 10 MW of solar. This resource option was added to the AURORA LTCE model.

Geothermal

Potential for commercial geothermal generation in the Pacific Northwest includes both flashed steam and binary cycle technologies. Based on exploration to date in southern Idaho, binary-cycle geothermal development is more likely than flashed steam within Idaho Power's service area. 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.

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 2019 IRP assume a capital-cost of $6,495 per kW, and the 25-year LCOE is $144 per MWh based on an 88-percent annual capacity factor.

Hydroelectric

Hydroelectric power is the foundation of Idaho Power's electrical generation fleet. The existing generation is low cost and does not emit potentially harmful pollutants. The development of new, large hydroelectric projects is unlikely due to a lack of adequate sites and hurdles associated with regulatory, environmental, and permitting challenges that accompany new, large hydroelectric facilities. However, small-scale hydroelectric projects have been extensively developed in southern Idaho on irrigation canals and other sites; many of which have PPA contracts with Idaho Power.

Small Hydroelectric

Small hydroelectric projects, such as ROR and projects requiring limited 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 ISEA's Hydropower Task Force, and the results released in May 2009 indicate between 150 to 800 MW of new hydroelectric resources could be developed in Idaho. The reported 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 2019 IRP for small hydroelectric resources is a range from $4,000 per kW to $8,400 per kW, and an associated 75-year economic life.

Wind

Modern wind turbines effectively collect and transfer energy from windy areas into electricity. A typical wind development consists of an array of wind turbines ranging in size from 1 to 3 MW each. Most potential wind sites in southern Idaho lie between the south-central and the southeastern part of the state. Productive wind energy sites are in areas that receive consistent, sustained winds greater than 15 miles per hour and are the best candidates for wind development.

Upon comparison with other renewable energy alternatives, wind energy resources are well suited for the Intermountain and Pacific Northwest regions, as demonstrated by the large number of existing projects. Wind resources present unique operational challenges for electric utilities and system operators due to the intermittent and variable nature of wind-energy generation. To adequately account for the unique characteristics of wind energy, resource planning of new wind resources requires estimates of the expected annual energy and peak-hour capacity. For the 2019 IRP, Idaho Power applied a capacity factor of 5 percent for peak-hour planning. The 2019 IRP assumed an annual average capacity factor of 35 percent for projects sited in Idaho and 45 percent for projects sited in Wyoming. The capital-cost estimate used in the 2019 IRP for wind resources is $1,722 per kW, regardless of geographic location. The 25-year LCOE is $114 per MWh for projects located in Idaho and $94 per MWh for projects located in Wyoming.

Biomass

The 2019 IRP includes anaerobic digesters as a resource alternative. Multiple anaerobic digesters have been built in southern Idaho due to the size and proximity of the dairy industry and the large quantity of fuel available. Of the biomass technologies available, the 2019 IRP considers anaerobic digesters as a best fit for biomass resources within the service area.

The capital-cost estimate used in the 2019 IRP for an anaerobic digester project is $3,902 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 LCOE is $101 per MWh for the anaerobic digester.

Thermal Resources

While renewable resources have garnered significant attention in recent years, conventional thermal generation resources are essential to providing dispatchable capacity, which is critical in maintaining the reliability of a bulk-electrical power system. Conventional thermal 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 commonly used for baseload energy, while less-efficient SCCTs are used to generate electricity during peak-load periods. Additional details related to the characteristics of both types of natural gas resources are presented in the following sections. CCCT and SCCT resources are typically sited near existing natural gas transmission pipelines. All of Idaho Power's existing natural gas generators are located adjacent to a major natural gas pipeline.

Combined-Cycle Combustion Turbines

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

A traditional CCCT plant consists of a natural 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 to the atmosphere is reclaimed and used to produce additional power beyond that typically produced by an SCCT. New CCCT plants can be constructed or existing SCCT plants can be converted to combined-cycle units by adding a HRSG.

Multiple CCCT plants, like Idaho Power's Langley Gulch project, are planned in the region due to a sustained depression in natural gas prices, the demand for baseload energy, and additional operating reserves necessary to integrate intermittent resources. While there is not currently a scarcity of natural gas, fuel supply is a critical component of the long-term operation of a CCCT. The capital-cost estimate used in the 2019 IRP for a CCCT resource is $1,182 per kW, and the 30-year LCOE at a 60-percent annual capacity factor is $71 per MWh.

Simple-Cycle Combustion Turbines

SCCT natural gas 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 typically less economical on a per MWh basis. However, SCCTs can respond more quickly to grid fluctuations and can assist in the integration of variable and intermittent resources.

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

Idaho Power currently owns and operates 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 periods when the transmission system is constrained. The SCCT plants may also be dispatched based on economics during times when regional energy prices peak due to weather, fuel supply shortages, or other external grid influences.

The 2019 IRP evaluated a 170-MW industrial-frame (F class) SCCT unit. The capital-cost estimate used in the 2019 IRP is $1,009 per kW. The industrial-frame unit is expected to have an annual capacity factor of 5 percent.

Based on an annual capacity factor of 5 percent, the 35-year LCOE is $386 per MWh for the industrial-frame SCCT unit. If Idaho Power were to identify the need, it would evaluate the two types of SCCT technologies in greater detail prior to issuing an RFP to determine which technology would provide the greatest benefit.

Reciprocating Internal Combustion Engines

Reciprocating internal combustion engine (RICE) generation sets are typically multi-fuel engines connected to a generator through a flywheel and coupling. They are typically capable of burning natural gas. They are mounted on a common base frame resulting in the ability for an entire unit to be assembled, tuned, and tested in the factory before prior to delivery to the power plant location. This production efficiency minimizes capital costs. Operationally, reciprocating engines are typically installed in configurations with multiple identical units, allowing each engine to be operated at its highest efficiency level once started. As demand for grid generation increases, additional units can be started sequentially or simultaneously. 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 they can provide ancillary services to the grid in just a few minutes. Engines can go from a cold start to full-load in 10 minutes.

For the 2019 IRP, Idaho Power modeled RICE facilities of 55 MW and 111.1 MW nameplate capacity. The capital-cost estimate used for a reciprocating engine resource of 55 MW is $1,077 per kW. The 55 MW facility has a corresponding 40-year LCOE, assuming a 15-percent annual capacity factor, of $164 per MWh. Larger facilities can benefit from various economies of scale. The capital-cost estimate used for a RICE resource of 111.1 MW is $959 per kW. The 111.1 MW facility has a corresponding 40-year LCOE, assuming a 15-percent annual capacity factor, of $155 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 utilizing the heat generated in the process. These facilities are sometimes referred to as the 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 help the local economy.

In the evaluation of CHP resources, it became evident that CHP could be a relatively high-cost addition to Idaho Power’s resource portfolio if the steam host’s need for steam forced the electrical portion of the project to run at times when electricity market prices were below the dispatch cost of the plant. To find ways to make CHP more economical, Idaho Power is committed to working with individual customers to design operating schemes that allow power to be produced when it is most valuable, while still meeting the needs of the steam host's production process. This would be difficult to model for the IRP because each potential CHP opportunity could be substantially different. While not expressly analyzed in the 2019, Idaho Power will continue to evaluate CHP projects on an individual basis as they are proposed to the company.

Nuclear Resources

The nuclear power industry has been working to develop and improve reactor technology for many years and Idaho Power continues to evaluate various technologies in the IRP process. Due to the Idaho National Laboratory (INL) site located in eastern Idaho, the IRP has typically assumed that an advanced-design or small modular reactor (SMR) could be built on the site. In the wake of the 2011 earthquake and tsunami in Japan relating to the Fukushima nuclear plant, global concerns persist over the safety of nuclear power generation. While there have been new design and safety measures implemented, it is difficult to estimate the full impact this disaster will have on the future of nuclear power generation in the US. Idaho Power continues to monitor the advancement of SMR technology and will continue to evaluate it in the future as the Nuclear Regulatory Commission reviews proposed SMR designs in the coming years.

For the 2019 IRP, a 60-MW small-modular plant was analyzed. Grid services provided by the SMR include baseload energy, peaking capacity, and flexible capacity. The capital-cost estimate used in the IRP for an advanced SMR nuclear resource is $4,683 per kW, and the 40-year LCOE, evaluated at an annual capacity factor of 90 percent, is $121 per MWh.

Coal Resources

Conventional coal-fired generation resources have been a part of Idaho Power's generation portfolio since the early 1970s. Growing concerns over emissions and climate change coupled with historic-low natural gas prices, have made it imprudent to consider building any new conventional coal generation 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 coal resources. IGCC technology is also dependent on the development of carbon capture and sequestration technology that would allow CO_2 to be stored underground for long periods of time.

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

The addition of CO_2-capture equipment decreases the overall efficiency of an IGCC plant by as much as 15 percent. In addition, once the carbon is captured, it must either be used or stored for long periods of time. CO_2 has been injected into existing oil fields to enhance oil recovery;

however, if IGCC technology were widely adopted by utilities for power production, the quantities of CO_2 produced would require the development of underground sequestration methods. 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 2019 IRP.

Storage Resources

RPSs have spurred the development of renewable resources in the Pacific Northwest to the point where there is an oversupply of energy during select times of the year. Mid-Columbia wholesale market prices for electricity continue to remain relatively low. 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 be negative.

As increasing amounts of intermittent renewable resources like wind and solar continue to be built within the region, the value of an energy storage project increases. There are many energy-storage technologies at various stages of development, such as hydrogen storage, compressed air, flywheels, battery storage, pumped hydro storage, and others. The 2019 IRP considered a variety of energy-storage technologies and modeled battery storage 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. Commonly studied technologies include vanadium redox-flow battery (VRB), Li battery systems and Zinc battery systems.

Advantages of the VRB technology include its low cost, long life, and easy 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 just 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 replaced about every 10 years, whereas other battery technologies require a complete replacement of the battery and more frequently depending on use. Idaho Power recognizes the continued technological development of VRB and will continue to monitor price trends and utility scalability of this technology in the coming years.

In recent years Li battery systems have been installed commercially in the US. Li battery storage systems realize high charging and discharging efficiencies. Li-based energy storage devices present potential safety concerns due to overheating. Costs for Li battery systems are still relatively high. Idaho Power recognizes the continued technological development of Li batteries used in utility-scale storage facilities. Idaho Power will continue to monitor price trends and scalability of this technology in the coming years.

For the 2019 IRP, Idaho Power modeled Li battery technology in two arrangements. The first arrangement assumes 5 MW capacity with 20 MWh (4 hours) of energy. The capital-cost estimate for Li battery storage is $1,813 per kW. The 10-year LCOE, evaluated at an annual capacity factor of 11 percent, is $232 per MWh[10].

The second Li battery-storage arrangement modeled in the 2019 IRP analysis has a capital-cost estimate of $2,947 per kW. The 10-year LCOE, evaluated at an annual capacity factor of 23 percent, is $250 per MWh. This arrangement assumes 5 MW capacity with 40 MWh (8 hours) of energy.

Pumped-Storage Hydro

Pumped hydro storage is a type of hydroelectric power generation that is capable of consuming electricity during times of low value and generating electricity during periods of high value. 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 value of electricity between peak and off-peak times to overcome the costs incurred due to efficiency and other losses that make pumped storage a net consumer of energy overall. Typical round-trip cycle efficiencies are between 75 and 82 percent. The efficiency of a pumped hydro-storage facility is dependent on system configuration and site-specific characteristics. Historically, the differential between peak and off-peak energy prices in the Pacific Northwest has not been sufficient enough to make pumped storage an economically viable resource. Due to the recent increase in the number of wind and solar projects on the regional grid, the amount of intermittent generation provided, and the ancillary services required, Idaho Power will continue to monitor the viability of pumped hydro storage projects in the region. The capital-cost estimate used in the 2019 IRP for pumped hydro storage is $1,964 per kW, and the 75-year LCOE is $175 per MWh.

[10] The levelized energy costs for energy storage are driven overwhelmingly by fixed costs, particularly capital costs. Consequently, levelized costing for energy storage technologies in this chapter does not include the cost of recharge energy. While not insignificant, recharge energy costs are expectedly relatively small given the utilization of energy storage to recharge during acute periods of grid energy abundance.

5. Demand-Side Resources

Demand-Side Management Program Overview

DSM resources offset future energy loads by reducing energy demand through either efficient equipment upgrades (energy efficiency) or peak-system demand reduction (demand response). DSM resources have been a leading resource in IRPs since 2004, providing average cumulative system load reductions of over 240 aMW by year-end 2018. Historically, DSM potential resources have first been forecasted, screened for cost-effectiveness, and then all available DSM potential resources are included into the IRP before considering new supply-side resources. In the 2019 IRP, based on input from the IRPAC, two alternative approaches to estimate energy efficiency potential were tested and considered.

Idaho Power's Irrigation Peak Rewards program helps offset energy use on high-use days.

Included in the preferred portfolio is 440 MW of peak summer capacity reduction from demand response and 234 aMW of average annual load reduction from energy efficiency. Additionally, energy efficiency will reduce peak by 367 MW.

Energy Efficiency Forecasting—Potential Assessment

While Idaho Power tested alternative energy efficiency potential forecasting methods in the 2019 IRP, the underlying initial potential study was the same as the 2017 IRP methodology and served as a base case for comparison purposes. For the 2019 IRP, Idaho Power's third-party contractor (contractor), provided a 20-year forecast of Idaho Power's energy efficiency potential from a total resource cost (TRC) perspective. The contractor also provided additional forecasts based on different economic scenarios.

For the initial study, the contractor developed three levels of energy efficiency potential: technical, economic, and achievable. The three levels of potential are described below.

1. *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. In new construction, customers and developers are assumed to choose the most efficient equipment available. Technical potential also assumes the adoption of every applicable measure available. The retrofit measures are phased in over several years, which is increased for higher-cost measures.

2. *Economic*—Economic potential represents the adoption of all cost-effective energy efficiency measures. In the potential study, the contractor applies the 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 cost-effective and applicable measure.

3. *Achievable*—Achievable potential considers market adoption, customer preferences for energy-efficient technologies, and expected program participation. Achievable potential estimates 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 cost-effective potential for each energy efficiency measure. These factors represent the ramp rates at which technologies will penetrate the market.

Alternative DSM Modeling Methods

Idaho Power tested two alternate DSM modeling approaches in the 2019 IRP. In addition to the baseline potential study which assessed technical, economic, and achievable potential in a manner consistent with past IRPs, the company tested a sensitivity modeling method and a technically achievable potential supply curve bundling technique.

Sensitivity Modeling

The first alternative energy efficiency potential assessment method tested was a sensitivity modeling analysis. Under this approach, the contractor created three levels of achievable energy efficiency potential based on three different alternate cost forecasts. Each forecast corresponded to different natural gas price forecasts. The goal was to create differing levels of cost-effective energy efficiency based on the three sets of alternate costs that would be further analyzed in the AURORA portfolio selection process. Based on input from the IRPAC, the sensitivity approach was not adopted in the final IRP modeling because the method was observed to inappropriately screen energy efficiency potential at multiple steps in the process.

Technically Achievable Supply Curve Bundling

Based on input from IRPAC, a second approach was tested that established bundles of technically achievable energy efficiency potential. Technically achievable applies a market adoption factor intended to estimate those customers likely to participate in programs incentivizing more efficient processes and/or equipment, similar to the approach used when forecasting achievable potential.

The contractor created 10 technical achievable bundles of energy efficiency potential based on increasing efficiency costs and bundled by percentile. These technical achievable potential bundles were based on net levelized TRC across the 20-year planning period (0–10th percentile, 10th–20th percentile, etc.). An 11th bundle captured extremely high-cost measures above $250 per MWh. The bundles of energy efficiency measures or technologies were created across customer class and building types. For example, one cost bundle could contain residential, commercial, industrial, and irrigation measures if the underlying measures had similar costs. Table 5.1 lists the cumulative bundle resource potential in aMW over 20 years and the weighted average net levelized TRC over the same period.

Table 5.1 Technical achievable bundles size and average cost

Bundle	5-Year Potential (aMW) 2019	2023	2028	2033	2038	20 Year Net Average Real Cost ($/MWh)
0–10th Percentile	1	7	17	27	33	-$102
10–20th Percentile	3	8	17	27	33	-$18
20–30th Percentile	3	12	22	29	34	$14
30–40th Percentile	1	8	18	27	33	$32
40–50th Percentile	2	8	16	25	34	$38
50–60th Percentile	1	7	14	22	33	$48
60–70th Percentile	2	11	21	28	33	$69
70–80th Percentile	3	16	27	32	34	$131
80–90th Percentile	2	13	26	31	34	$133
90–100th Percentile	2	11	24	30	33	$189
High Cost	2	14	27	35	41	$2,235

Idaho Power makes every effort to ensure all cost-effective energy efficiency potential is fully accounted for in resource planning. Because Idaho Power's load forecast includes a level of cost-effective energy efficiency expected to occur during a given forecast period, an important step in this process was to compare the level of future cost-effective energy efficiency included in the 2019 IRP load forecast to bundled levels of efficiency represented in Table 5.1. This comparison concluded the amount of energy efficiency included in the first seven bundles of energy efficiency potential was approximately equal to the amount of efficiency potential included in the load forecast and the economic-achievable potential identified in the initial potential assessment. Thus, energy efficiency bundles for the zero through the 70th percentile are considered reflected in all IRP resource portfolios. The higher cost bundles, 8 through 11, were available to be selected by the AURORA model in the LTCE process but were shown to not be economically competitive against other resources.

The 0 to 10th and 10 to 20th percentile bundles' average TRCs are negative because the non-energy impacts exceed the cost. Figure 5.2 shows cumulative technical achievable energy efficiency potential beginning in 2019. The energy efficiency bundles from 0 to 70th percentile bundle are representative of the levels of energy efficiency included in 2019 IRP portfolios. Higher-cost bundles beyond the 60 to 70th percentile bundle were determined not to be economically competitive when compared with other resources. Table 5.1 shows that bundles beyond the 60 to 70th percentile bundle have weighted average measure costs of $131 per MWh or greater.

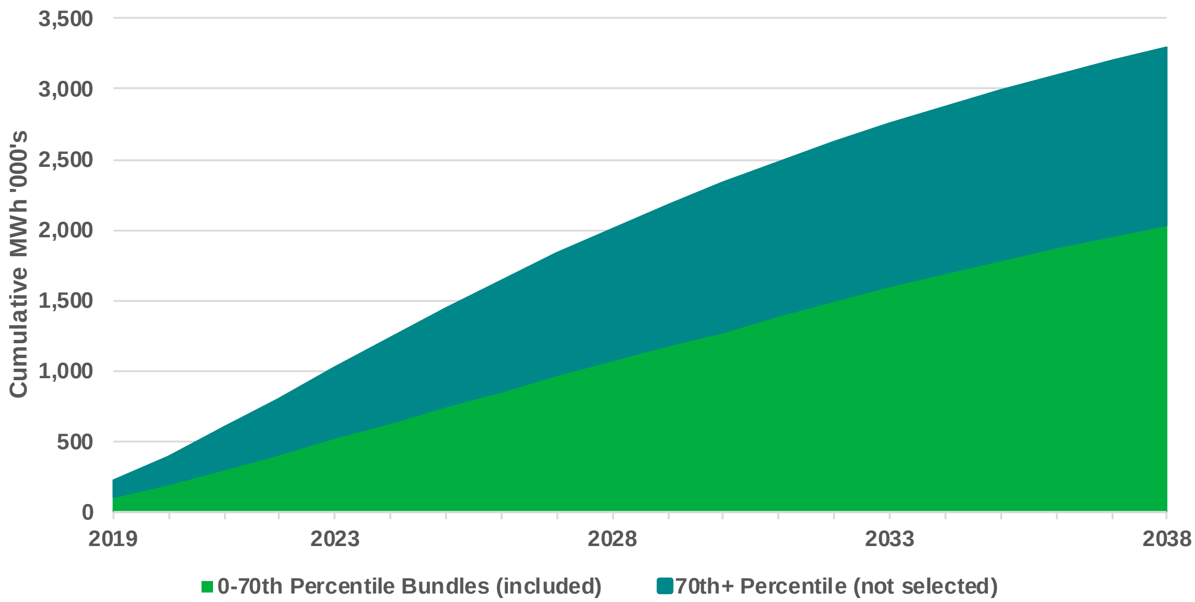


Figure 5.1 Energy-efficient bundles selected by the IRP model and bundles that were not economically competitive and were not selected for the 2019 IRP portfolios

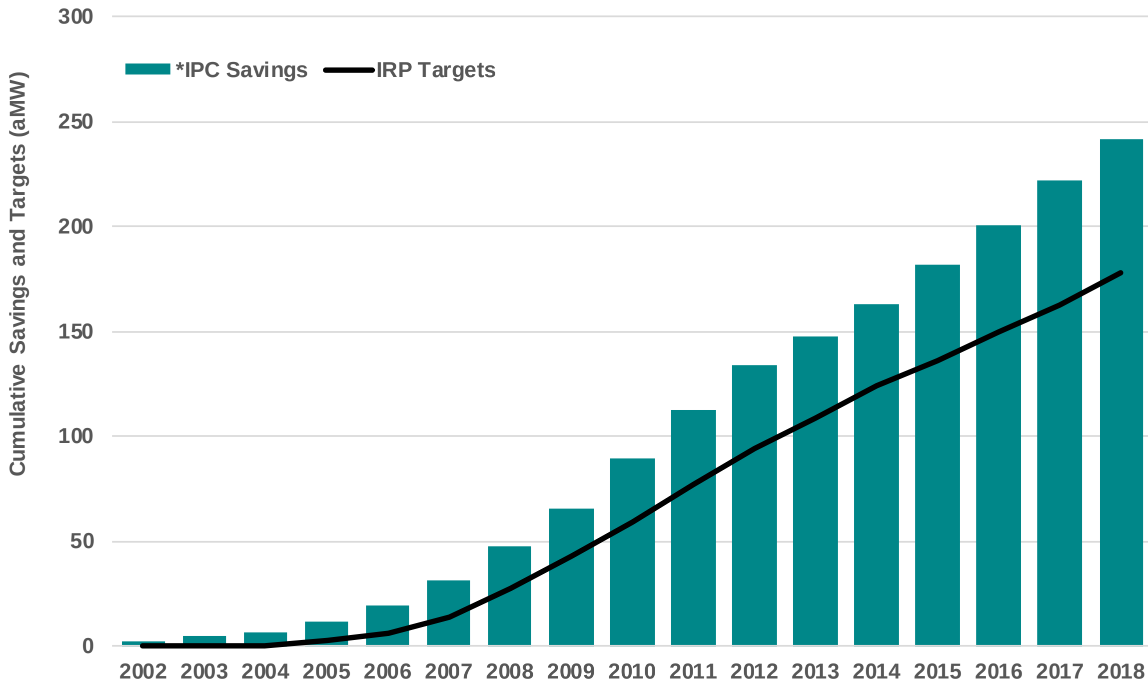
Future Energy Efficiency Potential

The 20-year energy efficiency potential included in the 2019 IRP declined from 273 aMW in 2017 IRP to 234 aMW in the 2019 IRP. System on-peak potential from energy efficiency also declined from 483 MW to 367 MW from the 2017 IRP to the 2019 IRP. Most of the decline in energy efficiency potential was due to the reduction of the number of residential lighting measures that will be available for Idaho Power energy efficiency programs. The *2007 Energy Independence and Security Act* manufacturing standard that will take effect in 2020 will increase efficiency standards for residential lighting. It is assumed this standard will only allow LED bulbs to meet manufacturing standards for most light bulbs that consumers purchase. Although the reduction from energy efficiency potential available for Idaho Power's programs will be reduced, the energy savings will still reduce overall load without utility intervention. A detailed discussion about the impacts on programs from codes and standards changes is available in the *2018 Energy Efficiency Potential Study*.

DSM Program Performance and Reliability

Energy Efficiency Performance

Energy efficiency investments since 2002 have resulted in a cumulative average annual load reduction of 242 aMW, or over 2 million MWh, of reduced supply-side energy production to customers through 2018. Figure 5.3 shows the cumulative annual growth in energy efficiency effects over the 17-year period from 2002 through 2018, along with the associated IRP targets developed as part of the IRP process since 2004.



* IPC savings include Northwest Energy Efficiency Alliance (NEEA) non-code/federal standards savings

Figure 5.2 Cumulative annual growth in energy efficiency compared with IRP targets

Idaho Power's energy efficiency portfolio is currently a cost-effective and low-cost resource. Table 5.2 shows the 2018 year-end program results, expenses, and corresponding benefit-cost ratios.

Table 5.2 Total energy efficiency portfolio cost-effectiveness summary, 2018 program performance

Customer Class	2018 Savings (MWh)	TRC ($000s)	Total Benefits ($000s) (20-Year NPV*)	TRC: Benefit/ Cost Ratio	TRC Levelized Costs (cents/kWh)
Residential	43,651	$13,634	$43,310	3.2	2.7
Industrial/commercial	95,759	$37,567	$70,324	1.9	3.2
Irrigation	19,001	$11,948	$36,344	3.0	7.6
Total	**158,411**	**$63,149**	**$149,978**	**2.4**	**3.4**

* NPV=Net Present Value

Note: Excludes market transformation program savings.

Energy Efficiency Reliability

The company contracts with third-party contractors to conduct energy efficiency program impact evaluations to verify energy savings and process evaluations to assess operational efficiency on a scheduled and as-required basis.

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.

Timing of impact evaluations are based on protocols from these industry standards with large portfolio contributors being evaluated more often and with more rigor. Smaller portfolio contributors are evaluated less often and require less analysis as most of the program measure savings are deemed savings from the RTF or other sources. Evaluated savings are expressed through a realization rate (reported savings divided by evaluated savings). Realized savings of programs evaluated between 2017 and 2018 ranged between 84 and 101 percent. The savings weighted realized savings average over the same period is 100 percent.

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. Table 5.3 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 2018 summer season, Irrigation Peak Rewards participants contributed 82 percent of the total potential demand-reduction capacity, or 313 MW. More details on Idaho Power's demand response programs can be found in *Appendix B—Demand-Side Management 2018 Annual Report*.

Table 5.3 2018 Demand response program capacity

Program	Customer Class	Reduction Technology	2018 Total Demand Response Capacity (MW)	Percent of Total 2018 Capacity*
A/C Cool Credit	Residential	Central A/C	37	10%
Flex Peak Program	Commercial, industrial	Various	33	9%
Irrigation Peak Rewards	Irrigation	Pumps	313	82%
Total			**383**	**100%**

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

Figure 5.4 shows the historical annual demand response program capacity between 2004 and 2018. The demand-response capacity was lower in 2013 because of the one-year suspension of both the irrigation and residential programs. The temporary program suspension was due to a lack of near-term capacity deficits in the 2013 IRP.

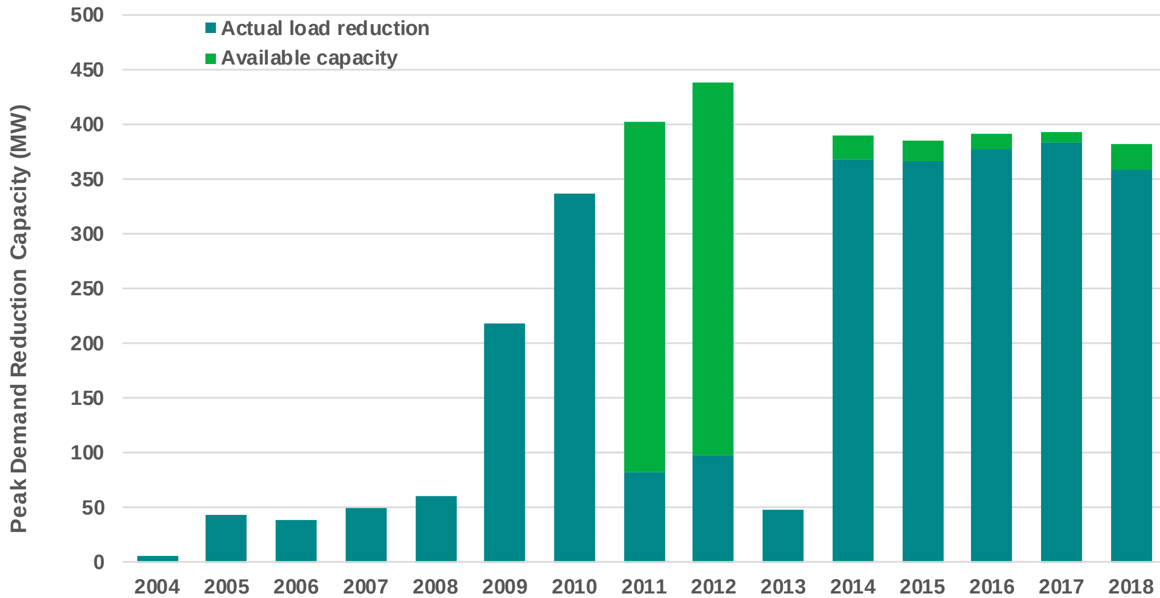


Figure 5.3 Historic annual demand response program performance

Demand Response Resource Potential

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

As part of the IRP's rigorous examination of the potential for expanded demand response, the company first evaluated additional demand-response capacity need outside of the AURORA model to determine any constraints needed in the modeling process. The company considered achievability and operability to properly model the potential expansion of demand response. Based on this analysis, the company made available 5 MWs of incremental new demand response each year for selection in AURORA starting in 2023. This additional demand response, beyond the 390 MWs the company considers a committed resource, was used in various amounts by the AURORA model in 23 of the 24 potential portfolios for a total of 420 MW available in the preferred portfolio. This expanded DR will require additional customer participation and was modeled in AURORA at a cost of $60 per kW-year.

T&D Deferral Benefits

Idaho Power determined the T&D deferral benefits associated with energy efficiency using historical and projected investments over a 20-year period from 2002 to 2021. Transmission, substation, and distribution projects at various locations across the company's system were represented. The limiting capacity (determined by distribution circuit or transformer) was identified for each project along with the anticipated in-service date, projected cost, peak load, and projected growth rate.

Varying amounts of incremental energy efficiency were used and spread evenly across customer classes on all distribution circuits. Peak demand reduction was calculated and applied to summer and winter peaks for the distribution circuits and substation transformers. If the adjusted forecast was below the limiting capacity, it was assumed an associated project—the distribution circuit, substation transformer, or transmission line—could be deferred. The financial savings of deferring the project were then calculated.

The total savings from all deferrable projects were divided by the total annual energy efficiency reduction required to obtain the deferral savings over the service area.

Idaho Power calculated the corresponding T&D deferral value for each year in the 20-year forecast of incremental achievable energy efficiency. The calculated T&D deferral values range from $6.52 per kW-year to $1.40 per kW-year based on a forecasted incremental reduction in system sales of between 0.86 percent to 0.43 percent from energy efficiency programs. The 20-year average is $3.74 per kW-year. These values will be used in the calculation of energy efficiency cost-effectiveness.

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 for Idaho Power customers. The transmission lines made it possible to develop a network of hydroelectric projects in the Snake River system, supplying reliable, low-cost energy. In the 1950s and 1960s, regional transmission lines stretching from the Pacific Northwest to the HCC and to the Treasure Valley were central for the development of the HCC projects. In the 1970s and 1980s, transmission lines allowed partnerships in three coal-fired power plants in neighboring states to deliver energy to Idaho Power customers. Today, transmission lines connect Idaho Power to wholesale energy markets and help economically and reliably mitigate variability of intermittent resources, and consequently are critical to Idaho Power's achievement of its goal to provide 100-percent clean energy by 2045.

Idaho Power's transmission interconnections provide economic benefits and improve reliability through the transfer of electricity between utilities to serve load and share operating reserves. Historically, Idaho Power experiences its peak load at different times of the year than most Pacific Northwest utilities; as a result, Idaho Power can purchase energy from the Mid-Columbia energy trading market during its peak load and sell excess energy to Pacific Northwest utilities during their peak. Additional regional transmission connections to the Pacific Northwest would benefit the environment and Idaho Power customers in the following ways:

- Delay or avoid construction of additional resources to serve peak demand
- Increase revenue from off-system sales during the winter and spring credited to customers through the PCA
- Increase revenue from sales of transmission system capacity credited to Idaho Power customers
- Increase system reliability
- Increase the ability to 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

Idaho Power uses a biennial process to create a local transmission plan (LTP) identifying needed transmission system additions. The LTP is a 20-year plan that incorporates planned supply-side resources identified in the IRP process, transmission upgrades identified in the local-area transmission advisory process, 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 evaluating these inputs, required transmission system enhancements are identified that will ensure safety and reliability. The LTP is shared with the regional transmission planning process.

A local-area transmission advisory process is performed every 10 years for each of the load centers identified, using unique community advisory committees to develop local-area plans. The community advisory committees include jurisdictional planners, mayors, city council members, county commissioners, and representatives from large industry, commercial, residential, and environmental groups. Plans identify transmission and substation infrastructure needed for full development of the local area, accounting for land-use limits, with estimated in-service dates for projects. Local-area plans are created for the following load centers:

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 the NTTG, a regional transmission planning group. The NTTG was formed in 2007 to improve the operation and expansion of the high-voltage transmission system that delivers power to consumers in seven western states. NTTG membership includes Idaho Power, 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.

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. Sets of lines that transmit power from one geographic area to another are known as transmission paths. Transmission paths are evaluated by WECC utilities to obtain an approved power transfer rating. Idaho Power has defined transmission paths to all neighboring states and between specific southern Idaho load centers as shown in Figure 6.1.

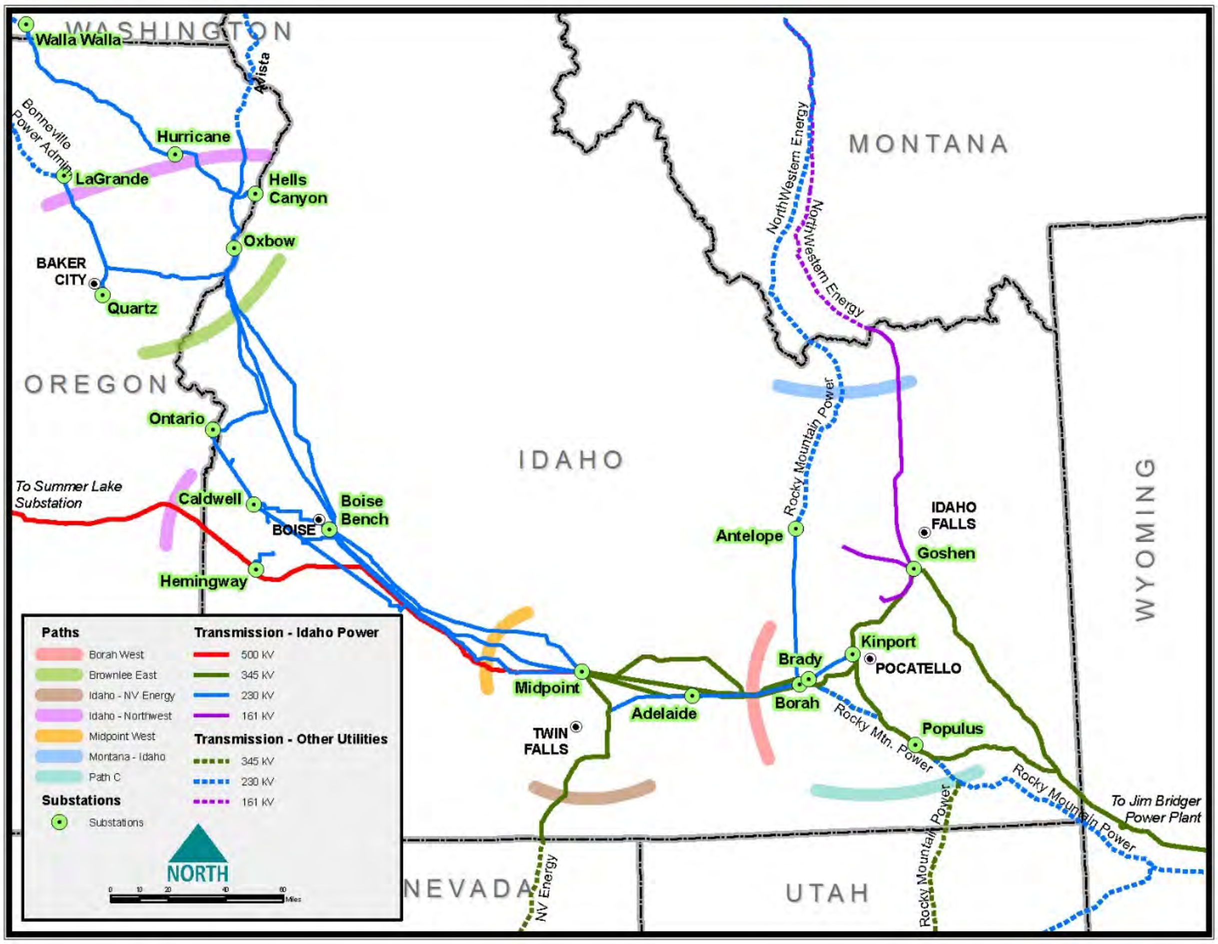


Figure 6.1 **Idaho Power transmission system map**

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. Additional transmission capacity is required to facilitate additional market purchases from northwest entities to serve Idaho Power's growing customer base.

Brownlee East Path

The Brownlee East transmission path is on the east side of the Idaho to Northwest path 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 Total Brownlee East 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 transfer from the HCC, as well as energy imports from the Pacific Northwest. If new resources, including market purchases, are located west of the path, additional transmission capacity will be required to deliver the energy to the Treasure Valley load center.

Idaho–Montana Path

The Idaho–Montana transmission path consists of the Antelope–Anaconda 230-kV and Goshen–Dillon 161-kV transmission lines. The 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 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. Currently, the available import, or northbound, capacity on the transmission path is fully subscribed with Idaho Power's share of the North Valmy generation plant. However, due to infrastructure improvements, in 2020 the northbound path limit will be increased from 262 to 360 MW.

The Jackpot Solar Project, described in the Power Purchase Agreements subsection of Chapter 3, will interconnect to this path at a substation north of the Idaho–Nevada border.

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 800 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 can be 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 can be limited by Borah West path capacity constraints.

Table 6.1 summarizes the import capability for paths impacting Idaho Power operations and lists their total capacity and available transfer capability (ATC); most of the 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 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).

Boardman to Hemingway

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 the needs of Idaho Power and other regional participants. The project, identified in 2006, has evolved into what is now B2H. 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 benefits of B2H in aggregate reflect its importance to the achievement of Idaho Power's goal to provide 100-percent clean energy by 2045 without compromising the company's commitment to reliability and affordability.

The B2H project has been identified as a preferred resource in the past five IRPs since 2009 and ongoing permitting activities have been acknowledged in every IRP short-term action plan since 2009. The 2017 IRP was the first IRP to include constructed activities in the near-term action plan. The 2017 IRP short-term action plan, and thus, B2H construction related activities, was acknowledged by both Idaho and Oregon PUCs.

Given the importance of the B2H project, the Company provides a dedicated IRP appendix, Appendix D: B2H Supplement, that provides granular detail regarding the Idaho Power's need for the project, co-participants, project history, benefits, risks, and more.

B2H is a regionally significant project; it has been identified as producing a more efficient or cost-effective plan in every NTTG biennial regional transmission plan for the past 10 years. NTTG regional transmission plans produce an efficient or cost-effective regional transmission plan meeting the transmission requirements associated with the load and resource needs of the NTTG footprint.

The B2H 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. In a November 17, 2017, US Department of the Interior press release,[11] B2H was held up as "a Trump Administration priority focusing on infrastructure needs that support America's energy independence…" The release went on to say, "This project will help stabilize the power grid in the Northwest, while creating jobs and carrying low-cost energy to the families and businesses who need it…"

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. As of September 30, 2019, BPA and PacifiCorp have collectively invested over $71 million towards project activities. Please refer to Appendix D for more information on project co-participants.

Figure 6.2 shows the transmission line route submitted to the ODOE in 2017.

[11] blm.gov/press-release/doi-announces-approval-transmission-line-project-oregon-and-idaho

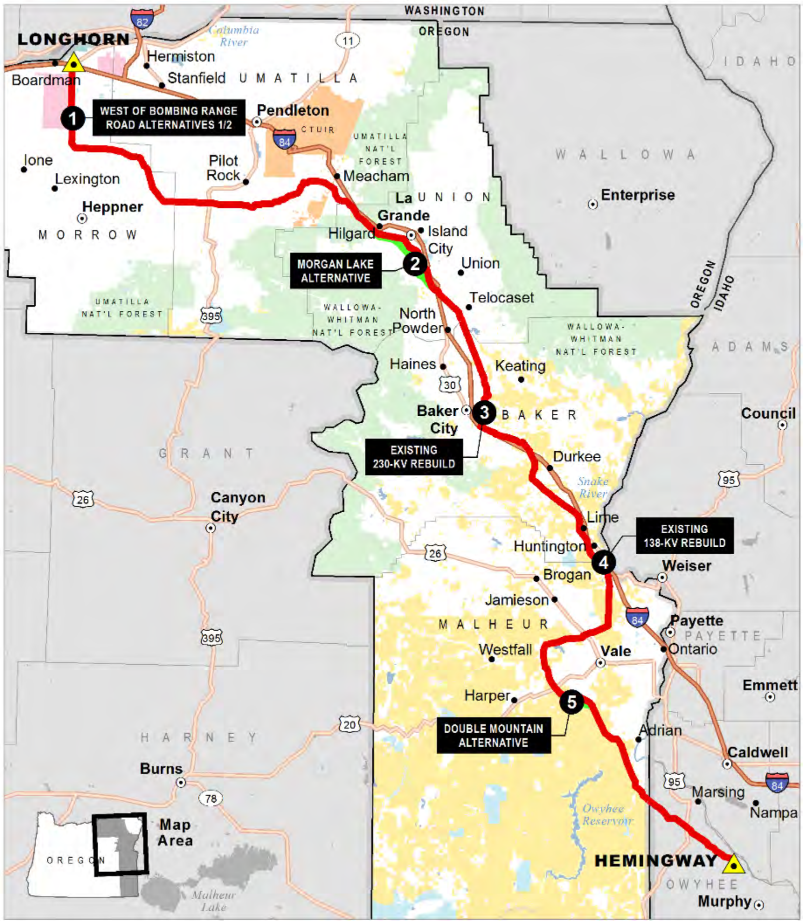


Figure 6.2 **B2H route submitted in *2017 EFSC Application for Site Certificate***

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 EIS, and the BLM issued a Record of Decision (ROD) on November 17, 2017.

The USFS issued a separate ROD on November 13, 2018 for lands administered by the USFS based on the analysis in the Final EIS. The USFS ROD approves the issuance of a special-use authorization for a portion of the project that crosses the Wallowa–Whitman National Forest.

For the State of Oregon permitting process, Idaho Power submitted the preliminary Application for Site Certificate (pASC) to the ODOE in February 2013 and submitted an amended pASC in summer 2017. The amended pASC was deemed complete by ODOE in September 2018. The ODOE and Energy Facility Siting Council (EFSC) reviewed Idaho Power's application for compliance with state energy facility siting standards and released a Draft Proposed

Order (DPO) for B2H on May 22, 2019. The EFSC will review the DPO findings and consider public testimony in its review and issue a Proposed Order, which is expected in early 2020.

The Oregon permitting process is expected to last through 2021. Permitting in Idaho will consist of a Conditional Use Permit issued by Owyhee County.

Idaho Power expects construction to begin in 2023, with the line in service in 2026.

Next Steps

With the DPO from the ODOE, sufficient route certainty exists 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 B2H project receives a Final Order and Site Certificate from EFSC, construction activities will 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. Transmission wheeling revenues, however, are not included in AURORA calculations. To remedy this inconsistency, in the 2017 IRP, Idaho Power modeled incremental transmission wheeling revenue from non-native load customers as an annual revenue credit for B2H portfolios. In the 2019 Amended IRP, Idaho Power continued to model expected incremental third-party wheeling revenues as a reduction in costs ultimately borne by retail customers.

Idaho Power's transmission assets are funded by native load customers, network customers, and point-to-point transmission wheeling customers based on a ratio of each party's usage of the transmission system. Portfolios involving B2H result in a higher FERC transmission rate than portfolios without B2H. Although B2H provides significant incremental capacity, and will likely result in increased transmission sales, Idaho Power assumed flat sales volume as a conservative assumption. The flat sales volume, applied to the higher FERC transmission rate, results in the cost offset for IRP portfolios with B2H.

In IRP modeling, Idaho Power assumes a 21.2-percent share of the direct expenses corresponding to Idaho Power's interest in the B2H Permit Funding Agreement, plus its entire AFUDC cost, which equates to approximately $292 million. Idaho Power also included costs for local interconnection upgrades totaling $21 million.

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 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 19, 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. On April 18, 2018, the BLM released the Decision Record granting approval of a ROW for Idaho Power's proposed routes for segments 8 and 9.

In its 2017 IRP, PacifiCorp announced plans to construct a portion of the Gateway West Transmission Line in Wyoming. PacifiCorp has subsequently worked towards construction of the 140-mile segment between the planned Aeolus substation near Medicine Bow, Wyoming, and the Jim Bridger power plant near Point of Rocks, Wyoming.

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

Unlike the B2H project, Gateway West will not provide direct access to a liquid market; however, it will provide many benefits to Idaho Power customers, including the following:

- Relieve Idaho Power's constrained transmission system between the Magic Valley (Midpoint) and the Treasure Valley (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.
- Provide the option to locate future generation resources east of the Treasure Valley.
- Provide future load-service capacity to the Magic Valley from the Cedar Hill Substation.
- 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.

For the 2019 IRP, Idaho Power believes the retirement of North Valmy generation plant can be adequately replaced with wholesale capacity imports across the Idaho–Nevada transmission path. The depth of the market and associated availability of resources is not as certain for the Idaho–Nevada path as it is for the Idaho-Northwest path during summer peak hours so import availability will continue to be evaluated in the future.

Transmission Assumptions in the IRP Portfolios

Idaho Power makes resource location assumptions to determine transmission requirements as part of the IRP development process. 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.

Transmission lines under construction at the Hemingway substation.

Table 6.3 Transmission assumptions and requirements

Resource	Capacity (MW)	Cost Assumption Notes	Local Interconnection Assumptions	Backbone Transmission Assumptions
Biomass indirect—Anaerobic digester	35	Distribution feeder locations in the Magic Valley; displaces equivalent MW of portfolio resources in same region.	$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	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	Magic Valley location connecting to 46-kV sub-transmission or local distribution feeder.	4 miles of distribution rebuild at $150,000 per mile plus $100,000 in substation upgrades.	No backbone upgrades required.

Resource	Capacity (MW)	Cost Assumption Notes	Local Interconnection Assumptions	Backbone Transmission Assumptions
Natural gas—SCCT frame F class (Idaho Power's peaker plants use this technology)	170	Mountain Home location; displaces equivalent MW of portfolio resources in same region.	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	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	Langley Gulch location; displaces equivalent MW of portfolio resources in same region.	New Langley–Garnet 230-kV line with Garnet 230/138 transformer and Garnet 138-kV tap line. Bundle conductor on the Langley–Caldwell 230-kV line. Reconductor Caldwell–Linden.	No additional backbone upgrades required.
Natural gas—CCCT (1x1) F class with duct firing	300	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. Connect the 230-kV Danskin Power Plant to Hubbard line in-and-out of the 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	Location in Treasure Valley.	1-mile tap to existing 138-kV line and new 138-kV source substation.	No backbone upgrades required.
Nuclear—SMR	50	Tie into Antelope 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 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	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	Magic Valley location; displaces equivalent MW of portfolio resources in same region.	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	Location within 5 miles of Midpoint Substation; displaces equivalent MW of portfolio resources in same region.	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

Chobani plant near Twin Falls, Idaho.

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 2019 IRP. A more detailed discussion on these topics is included in *Appendix A—Sales and Load Forecast*.

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 air conditioning (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 2019 IRP.

The expected-case average energy (average load) and expected peak-hour demand forecast represent Idaho Power's most probable outcome for load requirements during the planning period. In addition, Idaho Power prepares other probabilistic load forecasts that address the load variability associated with abnormal weather and economic scenarios.

The expected, or median, 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 1.0 percent (over the period 2019 through 2038) is comprised of a residential load growth of 1.1 percent, a commercial load growth of 1.1 percent, an irrigation load growth of 0.8 percent, an industrial load growth of 0.6 percent, and an additional firm load growth of 1.2 percent.

The number of residential customers in Idaho Power's service area is expected to increase 1.7 percent annually from 464,670 at the end of 2018 to nearly 649,000 by the end of the planning period in 2038. Growth in the number of customers within Idaho Power's service area, combined with an expected declining consumption per customer, results in a 1.1-percent average annual residential load-growth rate over the forecast term.

Significant factors that influenced the outcome of the 2019 IRP load forecast include, but are not limited to, the following:

- Weather plays a primary role in the load forecast on a monthly and seasonal basis. In the expected case load forecast of energy and peak-hour demand, Idaho Power assumes average temperatures and precipitation over a 30-year meteorological measurement period (i.e., normal climatology). Probabilistic variations of weather are also analyzed.
- The economic forecast used for the 2019 IRP reflects the continued expansion of the Idaho economy in the near-term and reversion to the long-term trend of the service area economy. Customer growth was at a near standstill until 2012, but since then acceleration of net migration and business investment has resulted in renewed positive activity. Idaho has been the fastest growth rate state in the US in terms of population in both the 2017 and 2018 measurement periods. Going into 2017, customer additions have approached sustainable growth rates experienced prior to the housing bubble (2000 to 2004) and are expected to continue.
- Conservation impacts, including DSM energy efficiency programs, codes and standards, and other naturally occurring efficiencies, are integrated into the sales forecast. These impacts are expected to continue to erode use per customer over much of the forecast period. 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).
- 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-case 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.
- The electricity price forecast used to prepare the sales and load forecast in the 2019 IRP reflects the additional plant investment and variable costs of integrating the resources identified in the 2017 IRP preferred portfolio. When compared to the electricity price forecast used to prepare the 2017 IRP sales and load forecast, the 2019 IRP price forecast has higher future prices. The retail prices are slightly higher throughout the planning period which can impact the sales forecast, a consequence of the inverse relationship between electricity prices and electricity demand.

Weather Effects

The expected-case load forecast assumes average temperatures and precipitation over a 30-year meteorological measurement period, or normal climatology. This implies a 50-percent chance loads will be higher or lower than the expected-case load forecast due to colder-than-normal or hotter-than-normal temperatures and wetter-than-normal or drier-than-normal precipitation. Since actual loads can vary significantly depending on weather conditions, additional scenarios for an increased load requirement were analyzed to address load variability due to abnormal weather—the 70th- 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.

Idaho Power's operating results fluctuate seasonally and can be adversely affected by changes in weather conditions and climate. Idaho Power's peak electric power sales are bimodal over a year, with demand in Idaho Power's service area peaking during the summer months. Currently, summer months exhibit a reliance on the system for cooling load in tandem with requirements for irrigation pumps. A secondary peak during the winter months also occurs driven primarily by colder temperatures and heating. As Idaho Power has become a predominantly summer peaking utility, timing of precipitation and temperature can impact which of those months demand on the system is greatest. Idaho Power tests differing weather probabilities hinged on a 30-year normal period. A more detailed discussion of the weather based probabilistic scenarios and seasonal peaks is included in *Appendix A—Sales and Load Forecast*.

Weather conditions are the primary factor affecting the load forecast on a monthly or seasonal basis. During the forecast period, economic and demographic conditions also 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 these 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 state of Idaho had the highest (or tied) growth rate of any state in the US for both 2017 and 2018. The number of households in Idaho is projected to grow at an annual rate of 1.3 percent during the forecast period, with most of the population growth centered on the Boise City–Nampa MSA. The Boise MSA (or the Treasure Valley) is an area that encompasses Ada, Boise, Canyon, Gem, and Owyhee counties in southwestern Idaho. In addition to the number of households, incomes, employment, economic output, and electricity prices are economic components used to develop load projections.

Idaho Power continues to manage a pipeline of prospective large load customers (over 1 MW)–both existing customers anticipating expansion and companies considering new investment in the state—that are attracted to Idaho's positive business climate and low electric prices. Idaho Power's business development strategy is focused on maximizing Idaho Power's generation resources and infrastructure by attracting new business opportunities to our service area in both Idaho and Eastern Oregon. The business development team benchmarks Idaho Power's service offerings against other utilities, partners with the states and communities to support local economic development strategies, and coordinates with large load customers engaged in a site selection process to locate in Idaho Power's service area.

The 2019 IRP average annual system load forecast reflects continued improvement in the service-area economy. The improving economic and demographic variables driving the 2019 forecast are reflected by a positive sales outlook throughout the planning period.

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 2019 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 compound annual growth rate in the expected case forecast is 1.0 percent during the 2019 through 2038 period. The projected 20-year average compound annual growth rate in the 70th- and 90th-percentile forecasts is 1.0 percent over the 2019 through 2038 period.

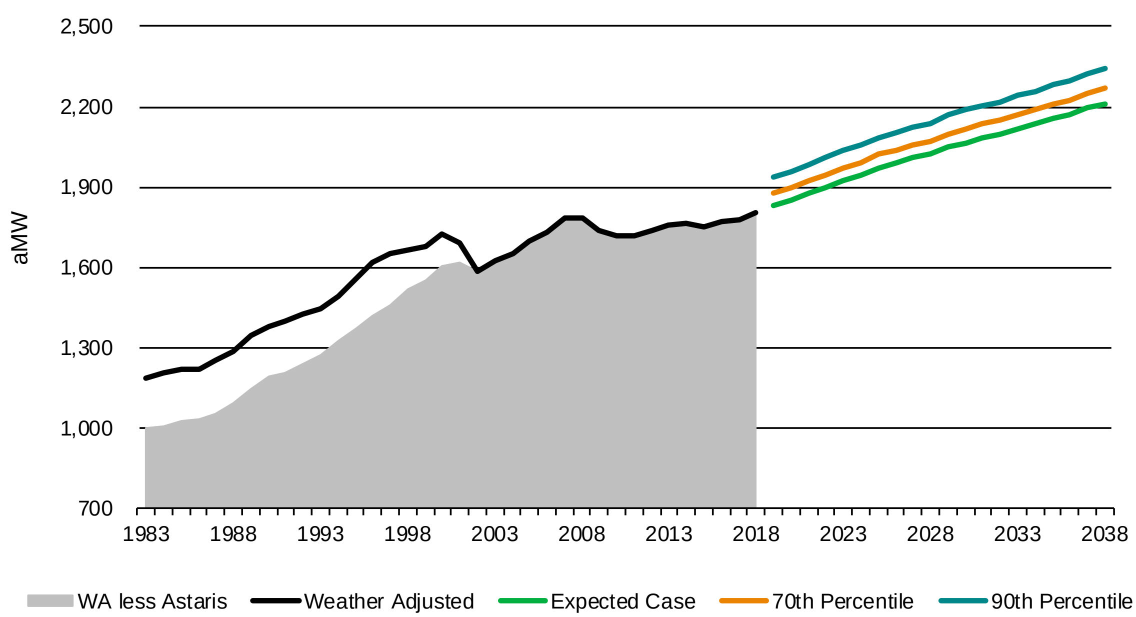


Figure 7.1 Average monthly load-growth forecast

Table 7.1 Load forecast—average monthly energy (aMW)

Year	Median	70th Percentile	90th Percentile
2019	1,833	1,878	1,939
2020	1,849	1,895	1,957
2021	1,876	1,922	1,985
2022	1,899	1,946	2,010
2023	1,923	1,970	2,035
2024	1,946	1,994	2,059
2025	1,972	2,021	2,087
2026	1,990	2,039	2,106
2027	2,008	2,057	2,125
2028	2,022	2,072	2,140
2029	2,048	2,098	2,167
2030	2,066	2,117	2,187
2031	2,084	2,136	2,206
2032	2,096	2,148	2,218
2033	2,117	2,169	2,241
2034	2,134	2,187	2,259
2035	2,154	2,208	2,280
2036	2,168	2,222	2,295
2037	2,194	2,249	2,322
2038	2,212	2,267	2,342
Growth Rate (2019–2038)	**1.0%**	**1.0%**	**1.0%**

Peak-Hour Load Forecast

The average-energy load forecast, as discussed in the preceding section, is an integral component to the load forecast. The peak-hour load forecast is similarly integral. 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's system peak-hour load record—3,422 MW—was recorded on Friday, July 7, 2017, at 5:00 p.m. Summertime peak-hour load growth accelerated in the previous decade as A/C became standard in nearly all new residential home construction and new commercial buildings. System peak demand slowed considerably in 2009, 2010, and 2011—the consequences of a severe recession that brought new home and new business construction to a standstill. Demand response programs operating in the summer have also been effective at reducing peak demand. The 2019 IRP load forecast projects annual peak-hour load to grow by nearly 50 MW per year throughout the planning period assuming a 1 in 20 (95th percentile) weather probability case on the day in which the annual peak-hour occurs. 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. As an example, the 95th-percentile forecast uses the 95th-percentile peak-day average temperature to determine monthly peak-hour demand. Alternative scenarios are based on their respective peak-day average temperature probabilities to determine forecast outcomes.

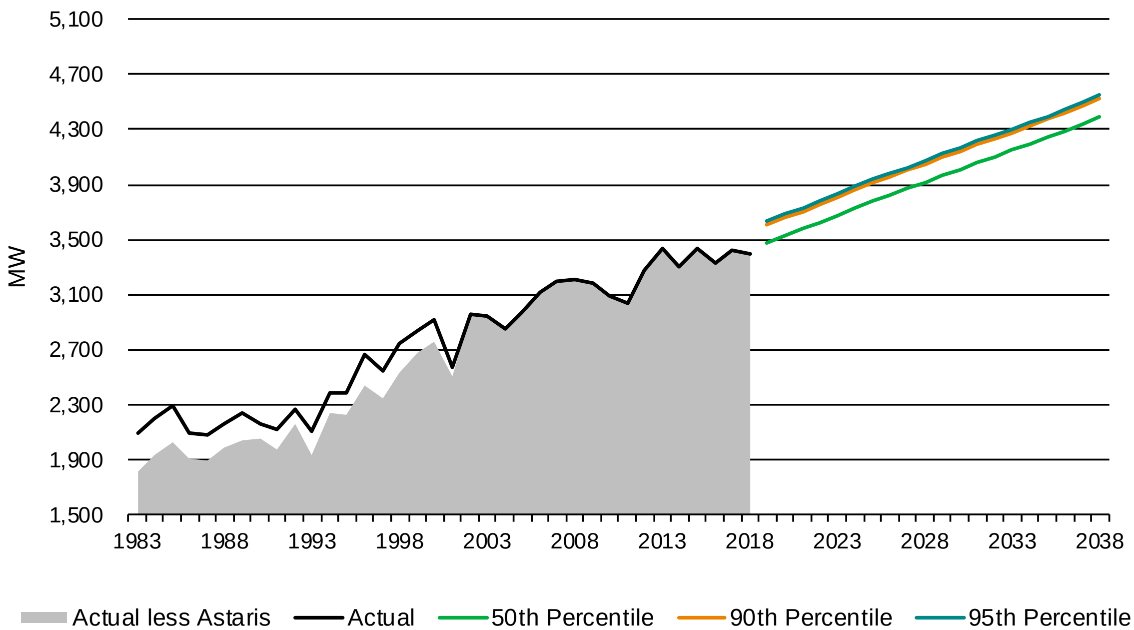


Figure 7.2 Peak-hour load-growth forecast (MW)

Table 7.2 Load forecast—peak hour (MW)

Year	Median	90th Percentile	95th Percentile
2018 (Actual)	3,392	3,392	3,392
2019	3,479	3,610	3,634
2020	3,528	3,659	3,683
2021	3,576	3,707	3,731
2022	3,627	3,757	3,782
2023	3,677	3,808	3,832
2024	3,732	3,863	3,887
2025	3,780	3,911	3,935
2026	3,825	3,956	3,980
2027	3,870	4,001	4,026
2028	3,918	4,048	4,073
2029	3,966	4,097	4,121

Year	Median	90th Percentile	95th Percentile
2030	4,012	4,143	4,167
2031	4,058	4,189	4,213
2032	4,103	4,234	4,258
2033	4,146	4,277	4,301
2034	4,193	4,324	4,348
2035	4,242	4,372	4,397
2036	4,291	4,422	4,446
2037	4,340	4,471	4,495
2038	4,388	4,519	4,544
Growth Rate (2019–2038)	**1.2%**	**1.2%**	**1.2%**

The median or expected case peak-hour load forecast predicts that peak-hour load will grow from 3,479 MW in 2019 to 4,388 MW in 2038—an average annual compound growth rate of 1.2 percent. The projected average annual compound growth rate of the 95th-percentile peak forecast is also 1.2 percent.

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 state 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 5,900 to 6,000 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

This facility named the Don Plant is located just outside Pocatello, Idaho. The Don Plant is one of four fertilizer manufacturing plants in the J.R. Simplot company's Agribusiness Group. Vital to fertilizer production at the Don Plant is phosphate ore mined at Simplot's Smoky Canyon Mine on the Idaho–Wyoming border. According to industry standards, the Don Plant is rated as one of the most cost-efficient fertilizer producers in North America. In total, J.R. Simplot company employees over 3,500 workers throughout its locations.

INL

INL is one of the US Department of Energy's (DOE) national laboratories and is the nation's lead laboratory for nuclear energy research, development, and demonstration. The DOE, in partnership with its contractors, is focused on performing research and development in energy programs and national defense. Much of the work to achieve this mission at INL is performed in government-owned and leased buildings on the Research and Education Campus in Idaho Falls, Idaho, and on the INL Site, located approximately 50 miles west of Idaho Falls. INL is recognized as a critical economic driver and important asset to the state of Idaho and is the fifth largest employer in the state of Idaho with an estimated 4,100 employees.

Generation Forecast for Existing Resources

Hydroelectric Resources

C.J. Strike Dam near Mountain Home, Idaho.

Idaho Power uses two primary models to develop 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 modeled streamflows are derived from the normalized hydrologic record. Further discussion of flow modeling for the 2019 IRP is included in *Appendix C—Technical Appendix*.

Streamflow trends in the upper Snake River Basin have been in decline for several years. Those declines are mirrored in documented declines in the ESPA. Water supply increased in 2016 and a significant runoff in 2017 resulted in Snake River flows at the King Hill gage exceeding 32,000 cfs (average peak 22,900 cfs). Water conditions in 2016 and 2017 allowed for large volumes of water to be diverted to aquifer recharge operations. The large runoff event in 2017 also resulted in a significant natural recharge event. Since 2015, water levels have improved throughout much of the ESPA. Improvement was noted in reach gains in 2016 and 2017; however, 2015 had near-record lows for some gaged springs. The increases are significant, but reach gains remain below long-term historic median flows.

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, flow augmentation shortages in 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 peak-hour analysis, a review of historical operations was performed to yield relationships between monthly energy production and achieved one-hour peak generation. The projected peak-hour capabilities for the IRP were derived to be consistent with the observed relationships.

A representative measure of the streamflow condition for any given year is the volume of inflow to Brownlee Reservoir during the April-to-July runoff period. Figure 7.3 shows historical April-to-July Brownlee inflow as well as modeled Brownlee inflow for the 50th, 70th, and 90th percentiles. The historical record demonstrates the variability of inflows to Brownlee Reservoir. The modeled inflows include reductions related to declining base flows in the Snake River and projected future management practices. As noted previously in this section, these declines are assumed to continue through the planning period.

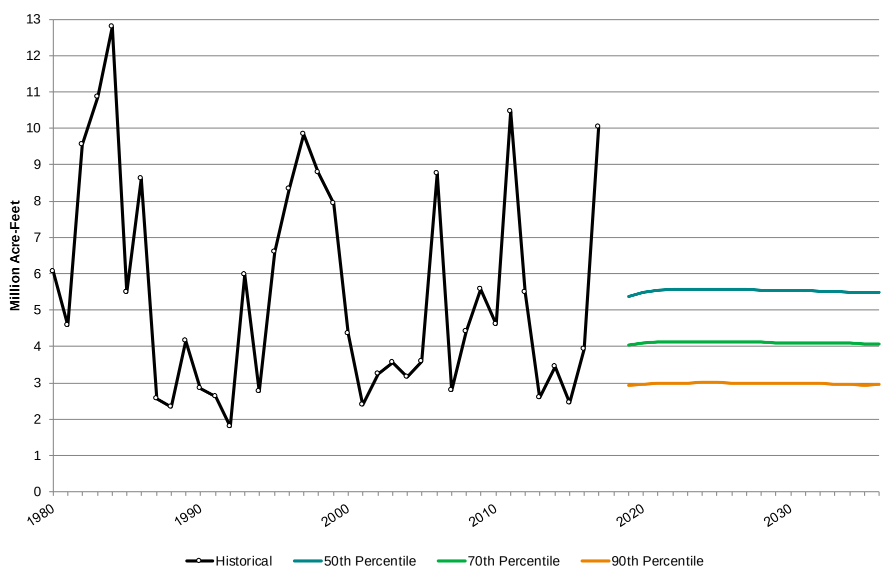


Figure 7.3 Brownlee inflow volume historical and modeled percentiles

Climate Change

Idaho Power recognizes the need to assess the impacts a changing climate may have on our resource portfolio and adaptively manage changing conditions. Idaho Power stays current on the rapidly developing climate change research in the Pacific Northwest. In 2018, two federal agency reports were issued on the potential impacts of climate change. The Fourth National Climate Assessment[12] and the River Management Joint Operating Committee (RMJOC)[13], Second Edition, Part 1 report addressed water availability in the Pacific Northwest under multiple climate change and response scenarios. Both reports highlighted the uncertainty related to future climate projections. However, most of the model projections show warming temperatures and increased precipitation into the future. The studies showed the natural hydrograph could see lower summer base flows, an earlier shift of the peak runoff, higher winter baseflows, and an overall increase in annual natural flow volume.

Idaho Power hydrogeneration facilities are at the lower end of a highly managed river system. Numerous reservoirs, diversions, and consumptive uses have resulted in changes to the timing of the natural hydrograph. For the 2019 IRP, Idaho Power performed a climate change analysis using datasets resulting from the RMJOC, Second Edition, Part 1 report to determine the impacts to the regulated streamflow through our system. Idaho Power used the University of Washington's modeled natural flow (hydro.washington.edu/CRCC/) and the SRPM to develop an average regulated streamflow into Brownlee Reservoir under projected future climates. The analysis included the evaluation of results from numerous general circulation models. The key findings of this analysis showed the following:

1. Reservoir regulation from systems above Idaho Power significantly dampens the effects of a potential shift in timing of natural runoff.
2. On average, July through January regulated streamflow is unaffected, February through May regulated streamflow shows an increase, and June shows a decrease in streamflow.
3. Most models analyzed agree in showing an average annual increase in streamflow volume.

Coal Resources

In the 2019 IRP, Idaho Power continues to analyze exiting from coal units before the end of their depreciable lives. The coal units continue to deliver generating capacity and energy during high-demand periods and/or during periods having high wholesale-electric market prices. Within the coal fleet, the Jim Bridger plant provides recognized flexible ramping capability enabling the company to demonstrate ramping preparedness required of EIM participants. Despite the system reliability benefits, the economics of coal plant ownership and operation remain challenging because of frequent low wholesale-electric market prices coupled with the need for capital investments for environmental retrofits. Moreover, the evaluation of exiting from coal unit

[12] nca2018.globalchange.gov/downloads/

[13] bpa.gov/p/Generation/Hydro/hydro/cc/RMJOC-II-Report-Part-I.pdf

participation is consistent with the company's expressed glide path away from coal and long-term goal to provide 100-percent clean energy by 2045.

Boardman

The 2019 IRP assumes Idaho Power exits its share of the Boardman plant at year-end 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; the agreement stipulates that coal-fired operations will cease at the plant by year-end 2020.

North Valmy

The 2019 IRP assumes Idaho Power ceases participation in North Valmy Unit 1 at year-end 2019 and Unit 2 no later than year-end 2025. This assumption is consistent with the company's regulatory filings in both jurisdictions that adjust customer rates to recover the incremental annual levelized revenue requirement associated with the early cessation of operations at North Valmy. Exit from Unit 2 earlier than 2025 was evaluated as part of the AURORA capacity expansion modeling; however, the AURORA model did not select Unit 2 for exit earlier than 2025 in any portfolio.

Jim Bridger

The four Jim Bridger units are assumed to reach the end of their depreciable lives in 2034. Units 1 and 2 currently require selective catalytic reduction (SCR) investment in 2021 and 2022 for continued unrestricted operations through 2034. The SCR investments on units 1 and 2 are not currently planned or included in the IRP analysis. PacifiCorp has submitted an application to the State of Wyoming for a Regional Haze Reassessment, which could provide an alternative to SCR installation on units 1 and 2.

In the AURORA-based LTCE modeling used to develop the 24 resource portfolios in the 2019 IRP, it was assumed that the Jim Bridger units could be selected for exit dates before 2034. The AURORA modeling included the costs of continued capital investment and accelerating the remaining book value of a unit identified for early exit to the year of exit. Additionally, an estimate of Bridger Coal Company costs was made based on the volume of coal burned, and if the burn was materially below the base mine plan a cost adder was included. The shared facilities costs are not included in the early unit exit decisions nor are SCR investments in units 1 and 2. The endogenous modeling of possible early exit dates was subject to the following guidelines intended to reflect a feasible exit:

- Unit 1—exit from participation 2022 through 2034
- Unit 2—exit from participation 2024 through 2034
- Unit 3—exit from participation 2026 through 2034
- Unit 4—exit from participation 2028 through 2034

The Jim Bridger units provide system reliability benefits, particularly related to the company's flexible ramping capacity needs for EIM participation and reliable system operations. The need for flexible ramping is simulated in the AURORA modeling as previously described. However, the AURORA modeling indicates removal of Jim Bridger units needs to be carefully evaluated because of potential heightened concerns about meeting regulating reserve requirements following their removal.

Natural Gas Resources

Idaho Power owns and operates four natural gas-fired SCCTs and one natural gas-fired CCCT, having combined nameplate capacity of 762 MW. The SCCT units are typically operated during peak-load events in the summer and winter. With respect to peaking capacity, they are assumed capable of producing an on-demand peak capacity of 416 MW, which is recognized by the AURORA model as contributing to the planning margin in capacity expansion modeling.

Idaho Power's CCCT, Langley Gulch, is typically dispatched more frequently and for longer runtimes than the SCCTs because of the higher efficiency rating of a CCCT. Langley Gulch is forecast to contribute 270 MW of on-demand peaking capacity available as contribution to the planning margin in capacity expansion modeling.

Natural Gas Price Forecast

To make continued improvements to the natural gas price forecast process, and to provide greater transparency, Idaho Power began researching natural gas forecasting practices used by electric utilities and local distribution companies in the region. Table 7.3 provides excerpts from IRP and avoided-cost filings, as an indication of the approaches used to forecast natural gas prices.

Table 7.3 Utility peer natural gas price forecast methodology

Utility	Gas Price Forecast Methodology
Rocky Mountain Power 2017 IRP	The October 2016 natural gas Official Forward Price Curve (OFPC), which was used in the 2017 IRP, was based on an expert third-party long-term natural gas forecast issued August 2016.
Avista Electric 2017 IRP	Avista uses forward market prices and a forecast from a prominent energy industry consultant to develop the natural gas price forecast for this IRP.
Avista Gas 2016 Natural Gas IRP	Avista reviewed several price forecasts from credible sources and created a blended price forecast to represent an expected price strip.
Portland General Electric (PGE) 2016 IRP	PGE derived the Reference Case natural gas forecast from market forward prices for the period 2017 through 2020 and the Wood Mackenzie long-term fundamental forecast for the period 2022 through 2035. A transition from the market price curve to Wood Mackenzie's long-term forecast is made by linearly interpolating for one year (2021).
Northwest Natural 2018 Oregon IRP	NW Natural's 2018 IRP natural gas forecast is of monthly prices developed by a third-party provider (IHS) based on market fundamentals. Cited source extracted from IHS Global Gas service and was developed as part of an ongoing subscription.
Intermountain Gas 2017 IRP	2017–2021 forecast based on an average of three five-year price forecasts for the Alberta Energy Company (AECO), Rockies, and Sumas pricing points from three different energy companies based on the May 26, 2016 market close.
Cascade Natural Gas Company 2018 Oregon IRP	Cascade's long-term planning price forecast is based on a blend of current market pricing along with long-term fundamental price forecasts. The fundamental forecasts include Wood Mackenzie, EIA, the Northwest Power and Conservation Council (NWPCC), Bentek (a S&P Global company), and the Financial Forecast Center's long-term price forecasts.

Based on the methodologies employed by Idaho Power's peer utilities, as well as feedback received during IRPAC meetings for the 2019 IRP, Idaho Power made the decision to enlist the service of a well-known third-party vendor as the source for the IRP planning case natural gas price forecast.

Idaho Power invited a representative of the third-party vendor to present to the IRPAC on October 11, 2018. The Platts forecast information below was presented by the vendor representative at the October 2018 IRPAC meeting.

The third-party vendor uses the following inputs/techniques to develop its gas price forecast:

- Supply/demand balancing network model of the North American gas market
- Oil and natural gas rig count data
- Model pricing for the entire North American grid
- Model production, transmission, storage, and multi-sectoral demand every month
- Individual models of regional gas supply/demand, pipelines, rate zones and structures, interconnects, capacities, storage areas and operations (160 supply areas, 272 pipelines, 444 storage areas, and 694 demand centers) and combines these models into an integrated North American gas grid
- Solves for competitive equilibrium, which clears supply and demand markets as well as markets for transportation and storage

Industry events that informed the third-party vendor uses 2018 natural gas price forecast include:

- Greater regionalization, with Gulf (export) dominance waning
- Status of North American major gas basins
- The emergence of the Northeast as a self-sufficient region, with a risk of periodic surplus and a chronic need for additional markets
- Texas/Southeast flow reversal to accommodate growing exports
- The absence of policy-driven demand growth (carbon), causing the Midwest to act as a "way station" for surplus gas
- The western US approaches saturation on policy limits, requiring West-coast liquefied natural gas (LNG) exports to lift demand
- Projected slowing of ramp in Appalachian pipeline use
- Northeast prices increasingly influenced by supply competition and energy transition, rather than pipe congestion

- The Permian basin may be overwhelmed by too much takeaway pipe if all projects are built
- Congestion and competition depress upstream prices in the West, while California ultimately competed with the premium Gulf
- Ample Midwest supply caps Chicago prices, while resource depletion supports the in-basin price of Rockies supply
- West-to-East disconnect in Canada, means that growth opportunities for Western Canadian Sedimentary Basin are tied to LNG aspirations
- Rising midstream costs have enabled diverse sources of supply to compete

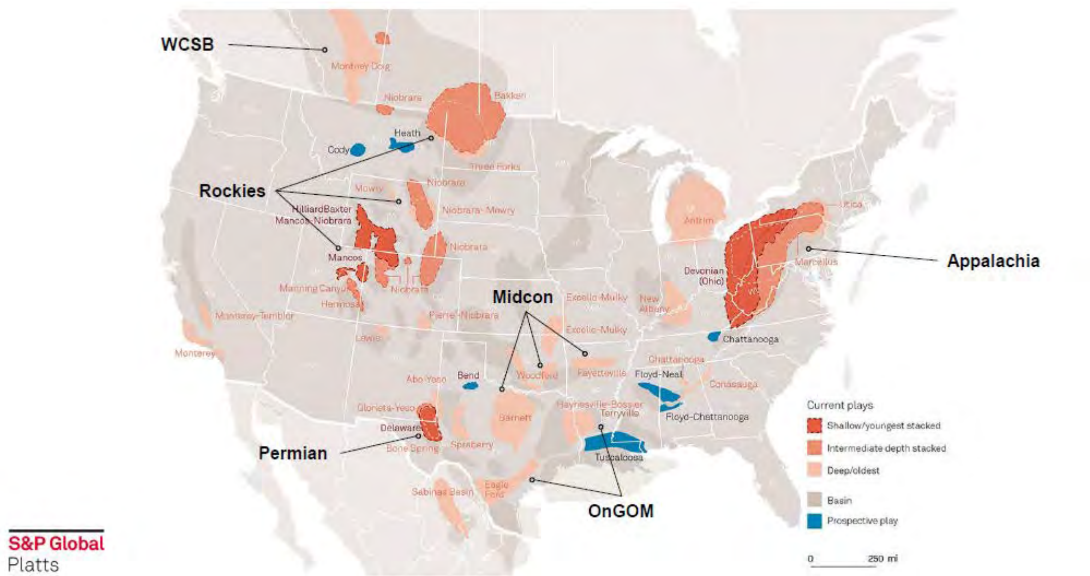


Figure 7.4 North American major gas basins

To verify the reasonableness of the third-party vendor’s forecast, Idaho Power compared the forecast to Moody’s Analytics and the New York Mercantile Exchange (NYMEX) natural gas futures settlements. Based on a thorough examination of the forecasting methodology and comparative review of the other sources (i.e., Moody’s and NYMEX), Idaho Power concluded that the third-party vendor’s natural gas forecast is appropriate for the planning case forecast in the 2019 IRP.

The third-party vendor’s 2018 Henry Hub long-term forecast, after applying a basis differential and transportation costs from Sumas, Washington (the location from which most of the supply is procured to fuel the company’s fleet of natural gas generation in Idaho), served as the planning case forecast of fueling costs for existing and potential new natural gas generation on the Idaho Power system.

Natural Gas Transport

Ensuring pipeline transportation capacity will be available for future natural gas-fired generation needs will require the reservation of pipeline capacity before a prospective resource’s in-service date. Idaho Power believes that turnback pipeline capacity from Stanfield, Oregon to Idaho could serve the need for natural gas-fired generating capacity for up to 600 megawatts (MW) of installed nameplate capacity. Williams' Northwest Pipeline has recently entered into a similar capacity reservation contract with a shipper where a discount was offered (a 10-cent rate versus full tariff of 39 cents) for the first five years before the implementation of full tariff rate for the remainder of the term. Using this information, a rate was applied reflective of the capacity reservation contract rate discounted until the in-service date, and full tariff thereafter.

Idaho Power projects that additional natural gas-fired generating capacity beyond an incremental 600 MW of capacity would require an expansion of Northwest Pipeline from the Rocky Mountain supply region to Idaho. The 600 MW limit, beyond which pipeline expansion is required, is derived from Northwest Pipeline's estimation of expected turnback capacity (existing contracts expiring without renewal) from Stanfield, Oregon to Idaho as presented in Northwest Pipeline's fall 2019 Customer Advisory Board meeting. Besides the uncertainty of acquiring capacity on existing pipeline beyond that necessary for 600 MW of incremental natural gas-fired generating capacity, a pipeline expansion would provide diversification benefits from the current mix of firm transportation composed of 60 percent from British Columbia, 40 percent from Alberta, and no firm capacity from the Rocky Mountain supply region. In response to a request for a cost estimate for a pipeline expansion from the Rocky Mountain supply region, Northwest Pipeline calculated a levelized cost for a 30-year contract of $1.39/ Million British Thermal Units (MMBtu)/day. Idaho Power applied this rate to potential natural gas-fired generation types with an assumption of high capacity factor (100 percent capacity coverage), medium capacity factor (33 percent), and low capacity factor (25 percent). For the medium and low capacity factor plants, it is assumed that transportation would be procured in the short-term capacity release market, or through delivered supply transactions to cover 100 percent of the requirements on any given day.

Analysis of IRP Resources

The electrical energy sector has experienced considerable transformation during the past 10 to 15 years. VERs, such as wind and solar, have markedly expanded their market penetration during this period, and through this expansion have affected the wholesale market for electrical energy. The expansion of VERs has also highlighted the need for flexible capacity resources to provide balancing. A consequence of the expanded penetration of VERs is periodic energy oversupply alternating with energy undersupply. Flexible capacity is primarily provided by dispatchable thermal resources (coal- and natural gas-fired), hydro resources, and energy storage resources.

For the 2019 IRP, Idaho Power continues to analyze resources based on cost, specifically the cost of a resource to provide energy and peaking capacity to the system. In addition to the capability to provide flexible capacity, the system attributes analyzed include the capability to provide dispatchable peaking capacity, non-dispatchable (i.e., coincidental) peaking capacity, and energy. Importantly, energy in this 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 LCOE. These metrics are discussed later in this section. Resources are evaluated from a TRC perspective. Idaho Power recognizes the TRC is not in all cases the realized cost to the company. Examples for which the TRC is not the realized cost include energy efficiency resources where the company incentivizes customer investment and supply-side resources whose production is purchased under long-term contract (e.g., PPA and PURPA). Nevertheless, Idaho Power views the evaluation of resource options using the TRC as allowing a like-versus-like comparison between resources, and consequently in the best interest of Idaho Power customers.

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 in AURORA.
Net levelized costing for the bundled energy efficiency resource options modeled in the IRP are provided in Chapter 5. The net levelized costs for energy efficiency resource options include annual program administrative and marketing costs, an annual incentive, and annual participant costs.

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 LCOC values for the potential IRP resources are provided in Figure 7.5.

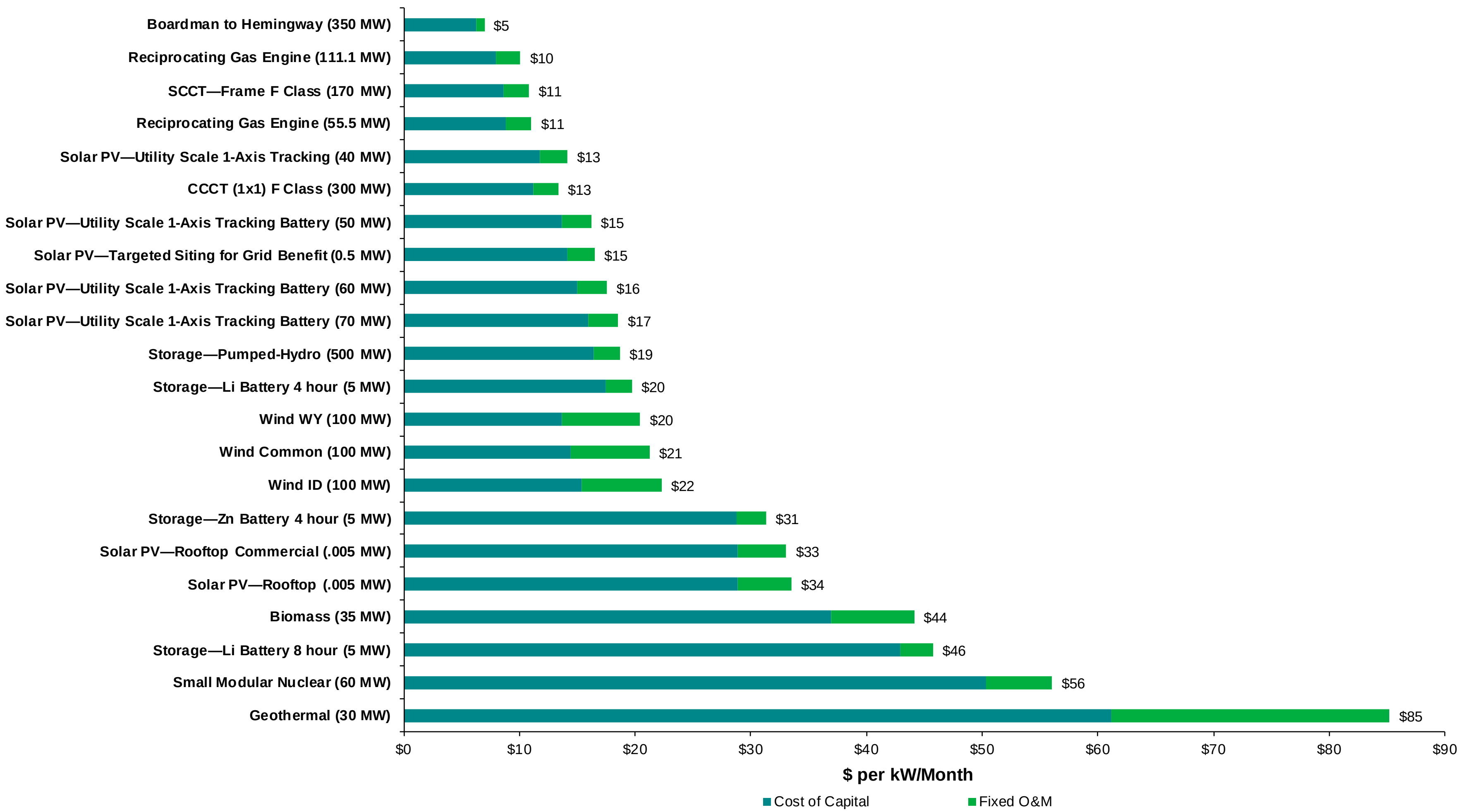


Figure 7.5 Levelized capacity (fixed) costs in 2019 dollars[14]

[14] Levelized capacity costs are expressed in terms of dollars per kW of *installed* capacity per month. The expression of these costs in terms of kW of *peaking* capacity can have significant effect, particularly for VERs (e.g., wind) having peaking capacity significantly less than installed capacity.

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 for wind and solar resources, and wholesale energy for B2H. The cost of recharge energy for storage resources is not included in the graphed LCOE values.

The LCOE is provided assuming a common on-line date of 2023 for all resources and based on Idaho Power specific financing assumptions. Idaho Power urges caution when comparing LCOE values between different entities or publications because the valuation is dependent on several underlying assumptions. The use of the common on-line date five years into the IRP planning period allows the LCOE analysis to capture projected trends in resource costs. The LCOE graphs also illustrate the effect of the Investment Tax Credit on solar-based energy resources, including coupled solar-battery systems. Idaho Power emphasizes that the LCOE is provided for informational purposes and is essentially a convenient summary metric reflecting the approximate cost competitiveness of different generating technologies. However, the LCOE is not an input into AURORA modeling performed for the IRP.

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 like 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 because 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.

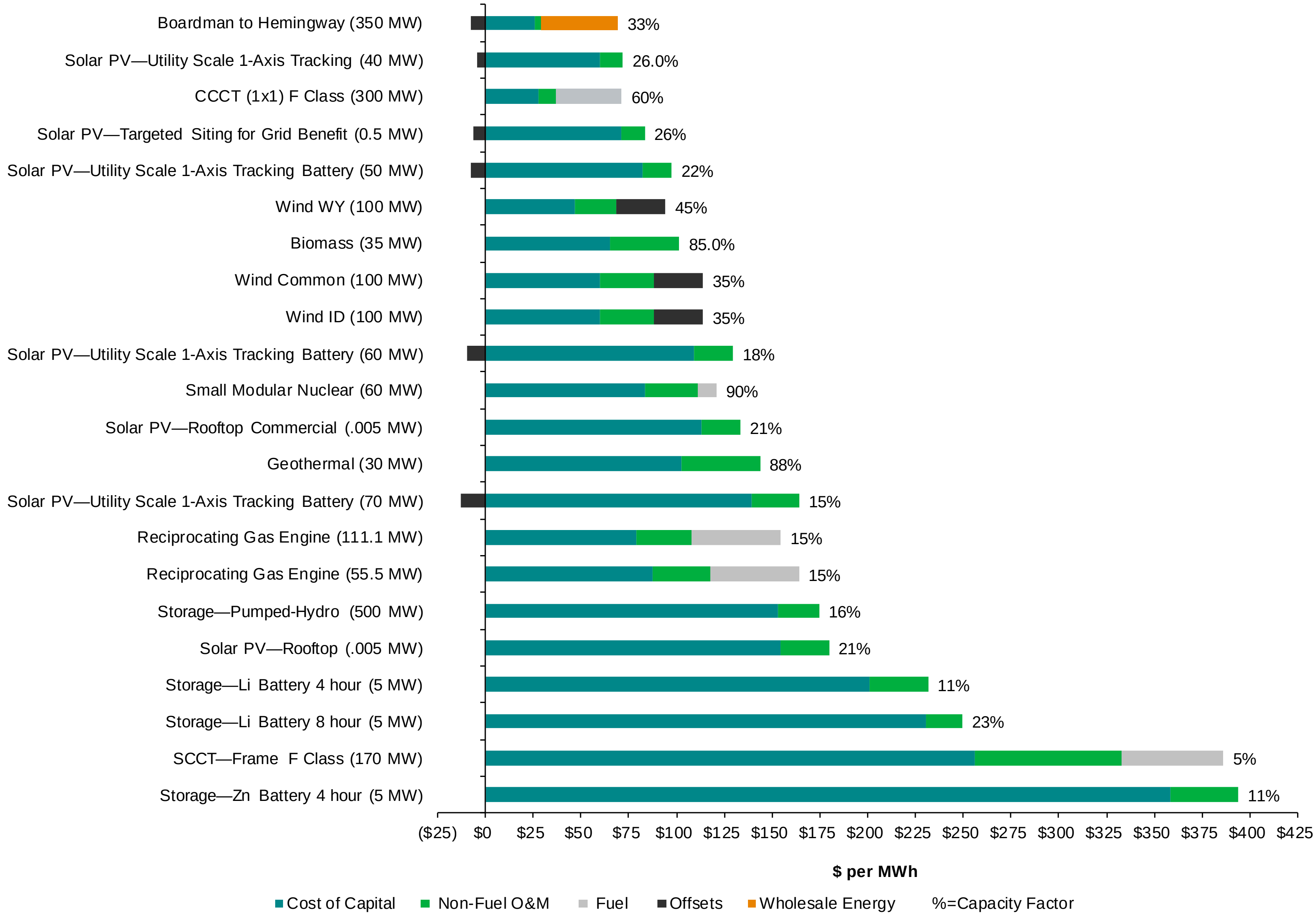


Figure 7.6 **Levelized cost of energy (at stated capacity factors) in 2023 dollars**

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 to the power system. For the LCOC metric, this critical distinction arises because of differences for some resources between *installed* capacity and *peaking* 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, Idaho wind is estimated to have an LCOC of $23 per month per kW of installed capacity.[15] However, assuming wind delivers peaking capacity equal to 5 percent of installed capacity, the LCOC ($23/month/kW) converts to $460 per month per kW of peaking 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 biomass resources have similar LCOEs. However, the energy output from biomass generating facilities tends to be delivered in a steady and predictable manner 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 biomass, 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 2019 IRP are classified based on their attributes. 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
- *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 7.4 provides classification of potential IRP resources with respect to the above attributes. The table also provides cost information on the estimated size potential and scalability for each resource.

[15] 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.

Table 7.4 Resource attributes

Resource	Intermittent Renewable	Dispatchable Capacity-Providing	Non-Dispatchable (Coincidental) Capacity-Providing[16]	Balancing/ Flexibility-Providing	Energy-Providing	Size Potential
Biomass—Anaerobic Digester		✓			✓	Scalable up to about 50 MW
B2H		✓		✓	✓	(200 MW Oct–March, 500 MW April–Sept)
Demand Response		✓				Scalable up to 50 MW
Energy Efficiency			✓		✓	Scalable up to achievable potential
Geothermal		✓			✓	Scalable up to about 50 MW
CCCT (1x1)		✓		✓	✓	300 MW increments
SCCT—Frame F Class		✓		✓		170 MW increments
Reciprocating Gas Engine		✓		✓	✓	18 MW increments
Small Modular Nuclear		✓		✓	✓	60 MW increments
Solar PV—Rooftop	✓		✓		✓	Scalable
Solar PV—Utility-Scale 1-Axis Tracking	✓		✓		✓	Scalable
Solar PV—Targeted Siting for Grid Benefit	✓		✓		✓	Scalable up to about 10 MW
Solar PV—AC Coupled with Lithium Battery	✓	✓			✓	Scalable
Storage—Pumped Hydro		✓		✓	✓	500 MW increments
Storage—Lithium Battery		✓		✓		Scalable
Wind (Wyoming/Idaho)	✓				✓	Scalable

[16] The peaking capacity impact in MW for resources providing coincidental peaking capacity is expected to be less than installed capacity in MW. For solar resources, the coincidental peaking capacity impact diminishes with increased installed solar capacity on system, as described in Chapter 4.

8. Portfolios

Capacity Expansion Modeling

For the 2019 IRP, Idaho Power used the LTCE capability of AURORA to produce WECC-optimized portfolios under various future conditions for natural gas prices and carbon costs. It is important to note that although the logic of the LTCE model optimizes resource additions based on the performance of the WECC as a whole, the resource portfolios produced by the LTCE and examined in this IRP are specific to Idaho Power. In other words, the term "WECC-optimized" refers to the LTCE model logic rather than the footprint of the portfolios being examined. Based on this definition, the WECC-optimized portfolios discussed in this document refer to the addition of supply-side and demand-side resources for Idaho Power's system and exits from current coal-generation units.

The selection of new resources in the WECC-optimized portfolios maintains sufficient reserves as defined in the model. To ensure the AURORA-produced WECC-optimized portfolios provide the least-cost, least-risk future specific to the company's customers, a subset of top-performing WECC portfolios was manually adjusted with the objective of further reducing portfolio costs specific to the Idaho Power system. This manual process is discussed further in the sections that follow.

Planning Margin

The 2019 IRP uses the LTCE capability of the AURORA model to develop portfolios compiled of different resource combinations. The model selects portfolios based on standards, policies, and resources needed- and does so in the least-cost manner. Idaho Power selected a 50th percentile hourly load forecast for the Idaho Power area and a 15 percent peak-hour planning margin to develop a 20-year, WECC optimized resource portfolios under a range of futures. The WECC portfolio includes a specific set of new resources and resource exits to reliably serve Idaho Power's load over the planning timeframe. Each portfolio is constrained by the peak-hour capacity planning margin and hourly flexibility requirements. As noted above, manual refinements to top-performing WECC optimized resource portfolios are used to ensure the least-cost, least-risk option has been identified specific to Idaho Power's service area.

Several factors influenced Idaho Power's decision to move to a 15 percent peak-hour planning margin in the 2019 IRP. The use of a percentage-based planning margin is a good fit with the use and logic in the AURORA model's LTCE functionality used in portfolio development. First, it is consistent with the NERC's N-1 Reserve Margin criteria.[17] Second, it is similar to the methodologies employed by Idaho Power's regional peer utilities for capacity planning.[18]

To validate the change from the prior IRP methodology, Idaho Power compared the 2017 IRP's 95th percentile peak-hour capacity, including the addition of 330 MW of capacity benefit margin (CBM) to the 50th percentile peak-hour forecast with a 15 percent planning margin as used in the

[17] nerc.com/pa/RAPA/ri/Pages/PlanningReserveMargin.aspx

[18] PacifiCorp 13-percent target planning margin (2017 IRP page 10), PGE 17 percent reserves planning margin (2016 IRP page 116), and Avista 14 percent planning margin (2017 IRP 6-1).

2019 IRP. As shown in Figure 8.1, the two methods do not result in significant differences. The series composed of the 95th percentile peak-hour value plus the 330 MW CBM does not include operating reserve obligations, which would be approximately 200 MW for a system load of 3,600 MW and higher for growing system loads.

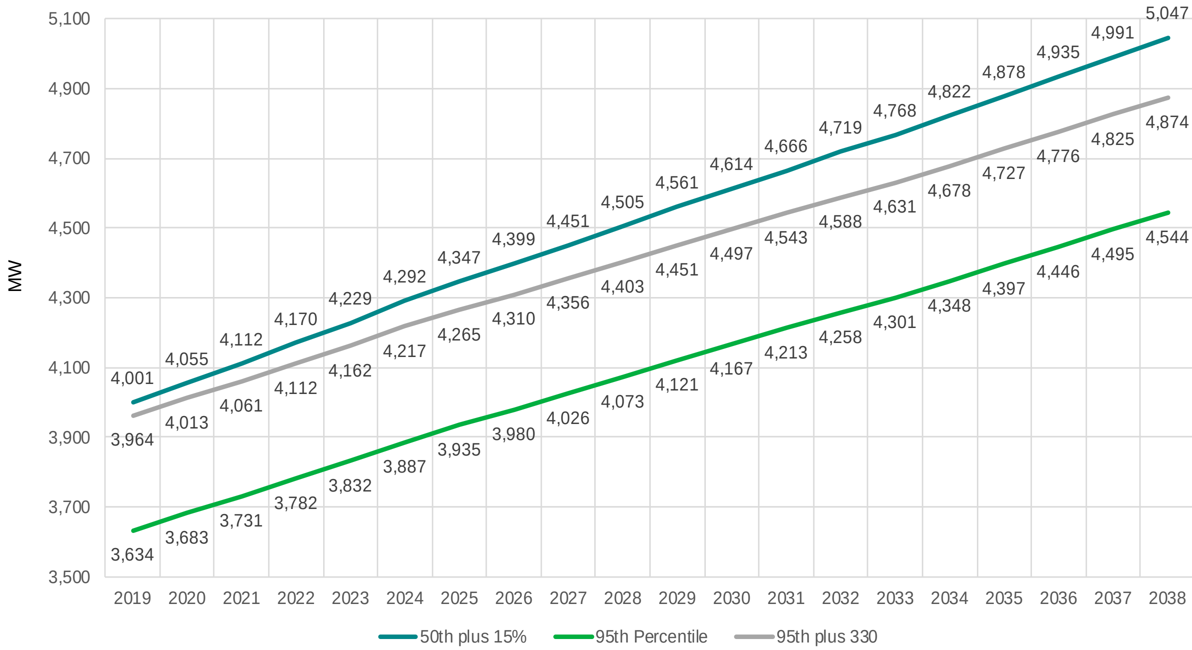


Figure 8.1 2017 versus 2019 IRP planning margin comparison (MW)

Portfolio Design Overview

The AURORA LTCE process develops future portfolios under varying future conditions for natural gas prices and carbon costs, selecting resources while applying planning margins and regulating reserve constraints, all with the objective of finding the least-cost solution. The future resources available possess a wide range of operating characteristics, and development and environmental attributes. The impact to system reliability and portfolio costs of these resources depend on future assumptions. Each portfolio consists of a combination of resources derived from the LTCE process that should enable Idaho Power to supply cost-effective electricity to customers over the 20-year planning period.

The use of an LTCE model that optimizes portfolio buildouts for the entire WECC region led the company to develop additional portfolios to ensure that it had reasonably identified an optimal solution specific to its customers. To accomplish this, a subset of top-performing WECC-optimized portfolios were manually adjusted with the objective of further reducing Idaho Power-specific portfolio costs while maintaining reliability. This method is described in greater detail in Chapter 9. The portfolios were then evaluated for operational, environmental, and qualitative considerations. The evaluation of the resources and portfolios culminate in an action plan that sets the stage for Idaho Power to economically and effectively prepare for the system needs of the future.

Previous IRP portfolio development included a concurrent evaluation of resource characteristics: quantitative and qualitative measures and risks when selecting a resource for inclusion in a specific portfolio for a future planning scenario. These portfolios were developed under low hydro and high peak forecast percentiles while considering the combined qualitative risks and various resource characteristics.

Using the AURORA LTCE process in portfolio design has some improvements compared to the prior resource selection methodology. The AURORA portfolio development process is more precise in using the defined resource characteristics and established quantitative requirements associated with those resources. Examples include increasing regulation requirements with solar generation additions or maintaining a peak hour planning margin and applying hourly regulating reserve requirements in the economic selection and timing of resource additions and retirements. Additionally, the LTCE process allowed the company and stakeholders to evaluate a relatively large number of portfolios relative to prior IRPs. In 2017, for example, the IRP examined 12 portfolios that were manually selected. However, in the 2019 IRP, the company evaluated 44 total portfolios, 24 of which were developed by the LTCE model, and 20 that were developed during the manual refinement process.

Regulating Reserve

Idaho Power characterized regulating reserve rules as part of its 2018 study of VER integration. To develop these rules for the VER study, Idaho Power analyzed one year of 1-minute time-step historical data for customer load, wind production, and solar production (December 2016 to November 2017). Based on this analysis, the company developed rules for bidirectional regulating reserve that adequately positioned dispatchable capacity to balance variations in load, wind, and solar while maintaining compliance with NERC's reliability standard.[19] The bidirectional regulating reserve was designated RegUp for the unloaded dispatchable capacity held to balance undersupply situations (i.e., supply less than load) and RegDn for loaded dispatchable capacity held to balance oversupply situations (i.e., supply exceeding load).

For the 2019 IRP, Idaho Power developed approximations for the VER study's regulating reserve rules. These approximations are necessary because a 20-year period is simulated for the IRP (as opposed to the single year of a VER study), and to allow the evaluation of portfolios containing varying amounts of VER generating capacity (i.e., the VER-caused regulating reserve requirements are calculable). The approximations express the RegUp and RegDn as dynamic and seasonal percentages of hourly load, wind production, and solar production. The approximations used for the IRP are given in tables 8.1 and 8.2. For each hour of the AURORA simulations, the dynamically determined regulating reserve is the sum of that calculated for each individual element.

[19] NERC BAL-001-2 (nerc.com/pa/Stand/Project%202010141%20%20Phase%201%20of%20Balancing%20Authority%20Re/BAL-001-2_Background_Document_Clean-20130301.pdf)

Table 8.1 RegUp approximation—percentage of hourly load MW, wind MW, and solar MW

RegUp	Winter[1]	Spring[2]	Summer[3]	Fall[4]
Load	8%	11%	7%	9%
Wind	38%	44%	48%	49%
Solar	69%	47%	53%	66%

[1]Winter: December, January, February
[2]Spring: March, April, May
[3]Summer: June, July, August
[4]Fall: September, October, November

Table 8.2 RegDn approximation—percentage of hourly load MW, wind MW, and solar MW

RegDn	Winter[1]	Spring[2]	Summer[3]	Fall[4]
Load	18%	29%	21%	29%
Wind	0%	0%	0%	0%
Solar	33%	0%	0%	0%

[1]Winter: December, January, February
[2]Spring: March, April, May
[3]Summer: June, July, August
[4]Fall: September, October, November

The RegDn rules for the VER study for wind and solar were expressed in terms of percentage of headroom above forecast production. For example, for a system having 300 MW of on-line solar capacity and forecast production for a given hour at 200 MW, the VER analysis found the percentage of 100 MW of headroom (300 to 200 MW) necessary to maintain system reliability. Given the substantial variations in VER generating capacity between portfolios, and temporally (i.e., year-to-year) within portfolios, it was impractical to approximate the RegDn regulating reserve for wind and solar production, except for the winter season for solar. It is emphasized that the regulating reserve levels used in the 2019 IRP are approximations intended to reflect generally the amount of set-aside capacity needed to balance load and wind and solar production while maintaining system reliability. The precise definition of regulating reserve levels is more appropriately the focus of a study designed specifically to assess the impacts and costs associated with integrating VERs.

Framework for Expansion Modeling

Idaho Power's LTCE modeling was performed under three natural gas price forecasts and four carbon price forecasts to develop optimized resource portfolios for a range of possible future conditions.

Natural Gas Price Forecasts

Idaho Power used the adjusted Platts 2018 Henry Hub natural gas price forecast as the planning case forecast in the 2019 IRP. Idaho Power also developed portfolios under two additional gas price forecasts: 1) the 2018 EIA Reference Case and 2) the 2018 EIA Low Oil and Gas (LOG) case.[20]

Carbon Price Forecasts

Idaho Power developed portfolios under four carbon price scenarios for the 2019 IRP shown in Figure 8.2:

1. Zero Carbon Costs—assumes there will be no federal or state legislation that would require a tax or fee on carbon emissions.
2. Planning Case Carbon Cost—is based on a carbon price forecast from a Wood Mackenzie report[21] released in June 2018. The carbon cost forecast assumes a price of $2/ton beginning in 2028 and increases to $22 per ton by the end of the IRP planning horizon. A key assumption in the report is that carbon costs would be regulated under a federal program and no state program is envisioned.
3. Generational Carbon Cost—is EPA's estimate of the social cost of carbon from 2016.[22] The social or generational cost of carbon is meant to be a comprehensive estimate of climate change impacts and includes, among other things, changes in net agricultural productivity, human health, property damages from increased flood risk, and changes in energy system costs. The generational carbon cost forecast assumes a price of $55.73 per ton starting in 2020 and increases to $101.16 per ton by the end of the IRP planning horizon.
4. High Carbon Costs—is based on the California Energy Commission's *Integrated Energy Policy Report* (IEPR) "Revised 2017 IEPR GHG Price Projections."[23] Idaho Power used the carbon price stream from the high price (low consumption) scenario and, for the 2019 IRP, assume carbon costs would begin in 2022 under a federal program. No state program is envisioned. The high carbon cost forecast assumes a price of $28.65 per ton starting in 2022 and increases to $107.87 per ton by the end of the IRP planning horizon.

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[20] EIA Annual Energy Outlook 2018, February 2018: eia.gov/outlooks/aeo/pdf/AEO2018.pdf

[21] "North America power & renewables long term outlook: Charting the likely energy transition page—the 'Federal Carbon' case."

[22] epa.gov/sites/production/files/2016-12/documents/social_cost_of_carbon_fact_sheet.pdf

[23] efiling.energy.ca.gov/GetDocument.aspx?tn=222145

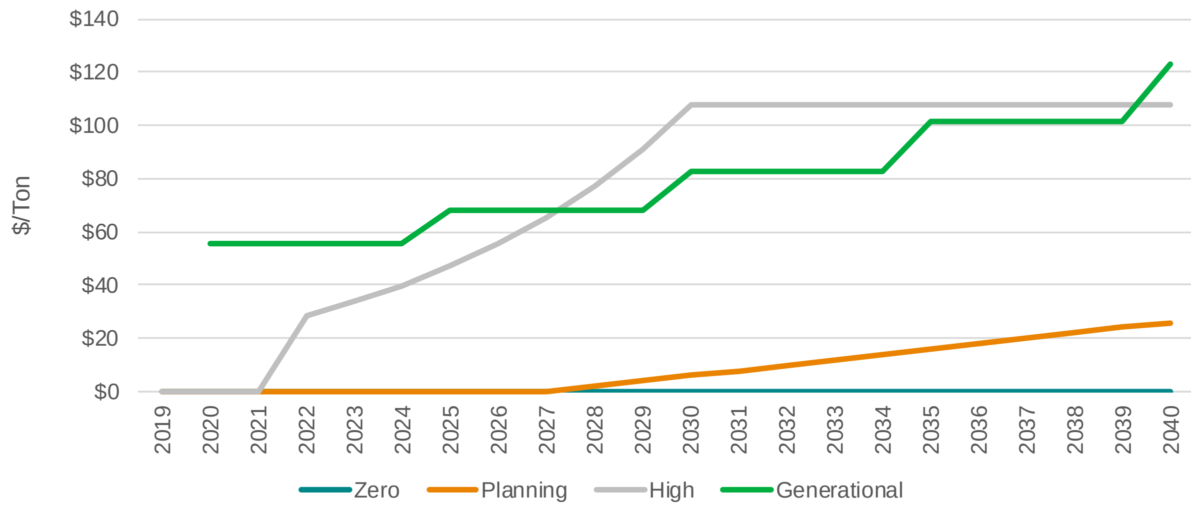

Figure 8.2 Carbon Price Forecast

Because the AURORA LTCE can evaluate generation units for economic retirement, Idaho Power provided baseline retirement assumptions in the AURORA model. The baseline retirement dates for Idaho Power's coal-fired generation is year-end 2034 for all Jim Bridger units. Any changes to these retirement dates would be determined through the portfolio modeling process.

Table 8.3 shows the 12 planned non-B2H portfolio designs resulting from the natural gas and carbon price forecasts.

Table 8.3 Non-B2H portfolio reference numbers

Non-B2H	Zero Carbon	Planning Carbon	Generational Carbon	High Carbon
Planning Gas	1	2	3	4
EIA Reference Gas	5	6	7	8
EIA LOG Gas	9	10	11	12

To evaluate the B2H project in the AURORA model, Idaho Power reproduced the same set of 12 portfolios with the inclusion of the B2H transmission line as a resource.

Table 8.4 shows the planned 12 B2H portfolio designs resulting from the natural gas and carbon price futures.

Table 8.4 B2H portfolio reference numbers

B2H	Zero Carbon	Planning Carbon	Generational Carbon	High Carbon
Planning Gas	13	14	15	16
EIA Reference Gas	17	18	19	20
EIA LOG Gas	21	22	23	24

WECC-Optimized Portfolio Design Results

The AURORA LTCE's model generated 24 different portfolios using all the assumptions described earlier. The 12 Non-B2H portfolios are shown in Figure 8.3, while the 12 B2H portfolios are shown in Figure 8.4. The details and timing of additional resources in the 24 WECC-optimized portfolios are included in *Appendix C—Technical Appendix*.

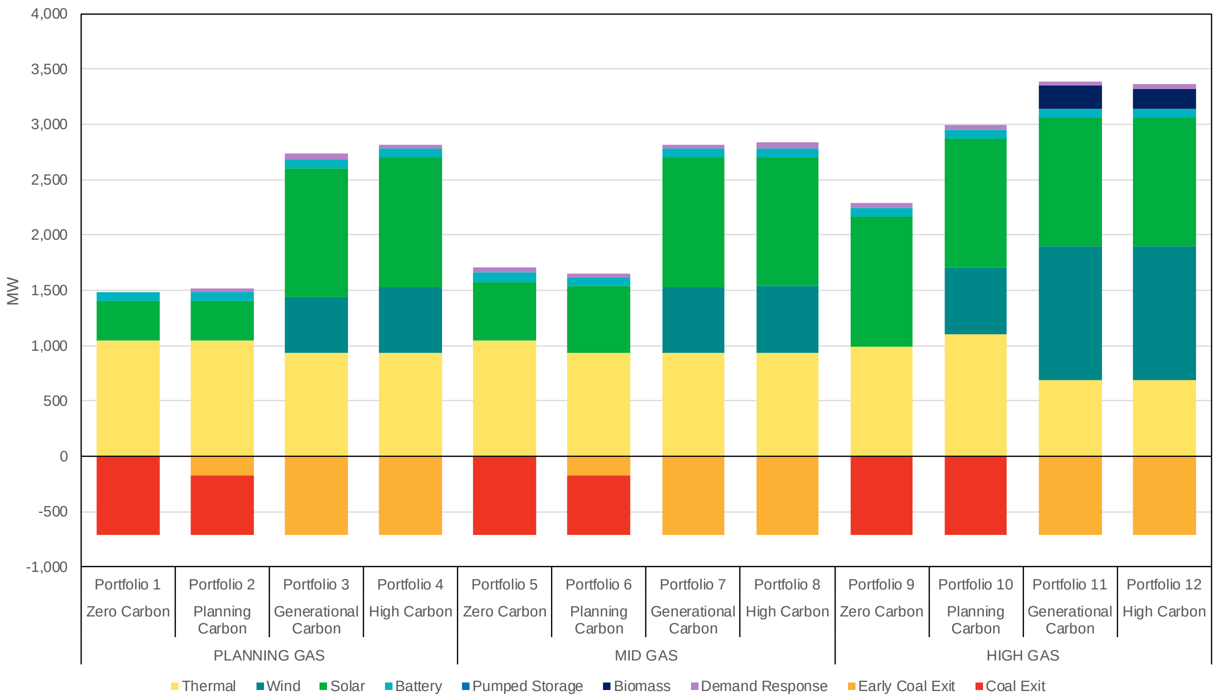

Figure 8.3 WECC-optimized portfolios 1 through 12 (non-B2H portfolios), capacity additions/reductions (MW)

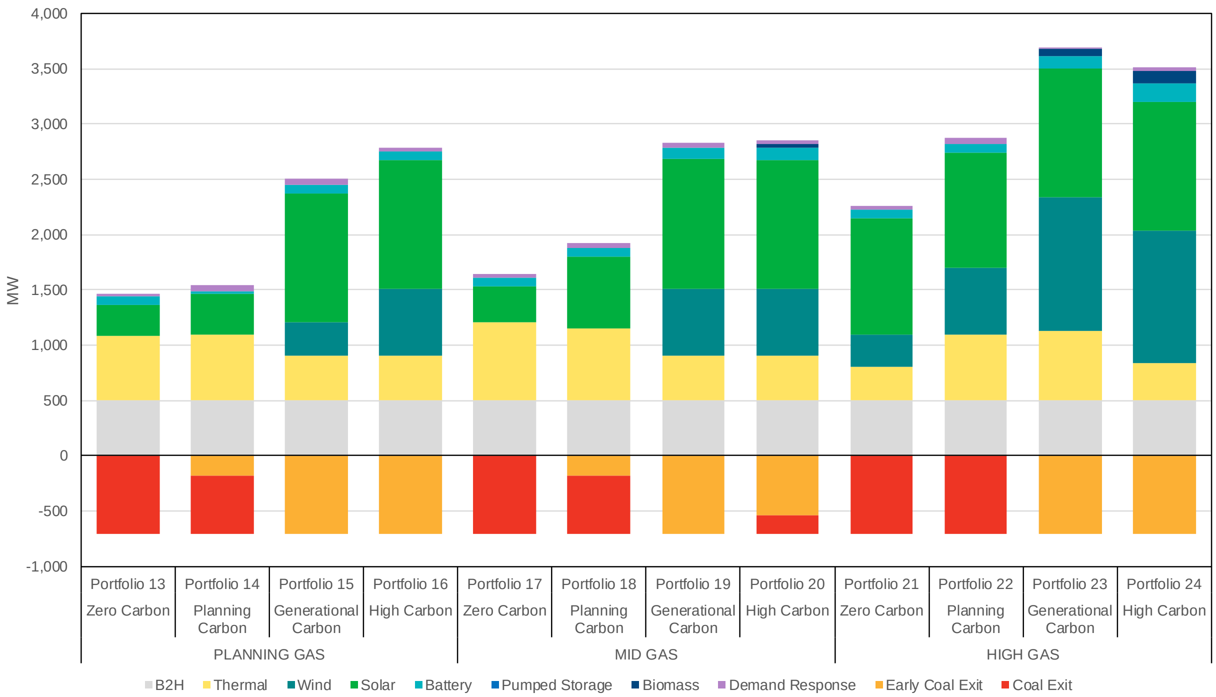

Figure 8.4 **WECC-optimized portfolios 13 through 24 (B2H portfolios), capacity additions/reductions (MW)**

Manually Built Portfolios

As noted earlier in this chapter, a subset of top-performing WECC-optimized portfolios was manually adjusted with the objective of further reducing Idaho Power-specific portfolio costs while maintaining reliability further reduction in Idaho Power-specific portfolio costs. The selected subset is composed of the following four portfolios with their associated natural gas and carbon futures, as well as their designation with respect to inclusion of B2H:

- Portfolio 2 (Planning Gas, Planning Carbon, without B2H)
- Portfolio 4 (Planning Gas, High Carbon, without B2H)
- Portfolio 14 (Planning Gas, Planning Carbon, with B2H)
- Portfolio 16 (Planning Gas, High Carbon, with B2H).

The analysis supporting the selection of these four portfolios for manual adjustment as well the process followed in manually adjusting the WECC portfolios, is discussed in the following chapter.

9. Modeling Analysis

Portfolio Cost Analysis

Once the WECC-Optimized portfolios are created using the LTCE model, 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. It should be noted that the Portfolio Cost Analysis is a step that occurs *following* the development of the resource buildouts through the LTCE model; the Portfolio Cost Analysis utilizes the resource buildouts from the LTCE model as an input. The LTCE and Portfolio Cost analyses cannot be performed simultaneously within the AURORA model due to the large computing requirements needed to perform the complex calculations inherent within the LTCE model.

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.

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	Expected life of asset
Discount rate (weighted average capital cost)	7.12%
Composite tax rate	25.74%
Deferred rate	21.30%
General O&M escalation rate	2.20%
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)	7.65%

The 24 WECC-optimized portfolios designed under the AURORA LTCE process were run through four different hourly simulations shown in Table 9.2.

Table 9.2 AURORA hourly simulations

	Planning Carbon	High Carbon
Planning Gas	X	X
High Gas	X	X

The purpose of the AURORA hourly simulations is to compare how portfolios perform under scenarios different from the scenario assumed in their design. For example, a portfolio designed under Planning Gas and Planning Carbon should perform better relative to other portfolios under a Planning Gas and Planning Carbon scenario than under a High Gas and High Carbon scenario. The compiled results from the four hourly simulations are shown in Table 9.3.

Table 9.3 2019 IRP WECC-optimized portfolios, NPV years 2019–2038 ($ x 1,000)

NPV ($ x 1000)	Planning Gas—Planning Carbon	High Gas—Planning Carbon	Planning Gas—High Carbon	High Gas—High Carbon
Portfolio 1	$6,262,350	$6,983,921	$8,615,746	$9,785,216
Portfolio 2	$6,180,898	$7,050,988	$8,268,640	$9,484,077
Portfolio 3	$6,743,579	$7,210,723	$7,758,806	$8,317,985
Portfolio 4	$6,711,725	$7,186,392	$7,764,683	$8,353,585
Portfolio 5	$6,247,134	$6,965,305	$8,640,298	$9,783,543
Portfolio 6	$6,295,506	$6,991,122	$8,671,032	$9,767,701
Portfolio 7	$6,997,047	$7,335,052	$7,883,018	$8,298,494
Portfolio 8	$6,921,411	$7,308,725	$7,845,686	$8,329,757
Portfolio 9	$6,351,648	$6,960,567	$8,563,652	$9,640,438
Portfolio 10	$6,857,192	$7,075,085	$8,319,929	$9,006,307
Portfolio 11	$7,936,126	$7,890,594	$8,512,277	$8,559,033
Portfolio 12	$7,866,893	$7,851,159	$8,408,693	$8,503,484
Portfolio 13	$6,298,486	$7,084,234	$8,966,855	$10,126,243
Portfolio 14	$6,131,430	$7,081,861	$8,426,982	$9,721,956
Portfolio 15	$6,484,416	$7,185,644	$7,780,477	$8,630,057
Portfolio 16	$6,632,764	$7,205,140	$7,802,154	$8,516,159
Portfolio 17	$6,306,492	$7,084,799	$8,943,907	$10,093,639
Portfolio 18	$6,155,638	$7,057,686	$8,641,689	$9,775,039
Portfolio 19	$6,770,655	$7,287,389	$7,878,895	$8,514,255
Portfolio 20	$6,852,642	$7,311,787	$8,080,079	$8,740,492
Portfolio 21	$6,483,530	$7,074,327	$8,795,307	$9,733,627
Portfolio 22	$6,511,244	$7,064,598	$8,722,004	$9,634,701
Portfolio 23	$7,230,853	$7,585,172	$8,151,311	$8,574,738
Portfolio 24	$7,380,489	$7,681,075	$8,228,451	$8,631,068

Under the Planning Gas and Planning Carbon scenario, P14 has the lowest NPV value of the 24 WECC-optimized portfolios at $6,131,430,000.

Figure 9.1 takes the information in Table 9.3 and compares all 24 portfolios on a two-axis graph that shows NPV cost under the planning scenario and the four-scenario standard deviation in NPV costs. The y-axis displays the NPV values under Planning Gas and Planning Carbon, and the x-axis displays the four-scenario standard deviation in NPV costs for the four scenarios shown in Table 9.3. Note that all cost scenarios are given equal weight in determining the four-scenario standard deviation. Idaho Power does not believe that each future has an equal likelihood, but for the sake of simplicity presented the results assuming equal likelihood to provide an idea of the variance in NPV costs associated with the four modeled scenarios.

Figure 9.1 shows that P14 is the lowest-cost portfolio under Planning Gas and Planning Carbon, although its four-scenario standard deviation is higher than some other portfolios. Conversely, P 24 has the lowest four-scenario standard deviation, but the highest expected cost under Planning Gas and Planning Carbon. Portfolios plotted along the lower and left edge of Figure 9.1 represent the efficient frontier in this graph of cost versus cost standard deviation. Moving vertically, portfolios plotting above the efficient frontier are considered to have equivalent cost variance, but higher expected cost. Moving horizontally, portfolios plotting to the right of the efficient frontier are considered to have equivalent expected cost, but greater potential cost variance.

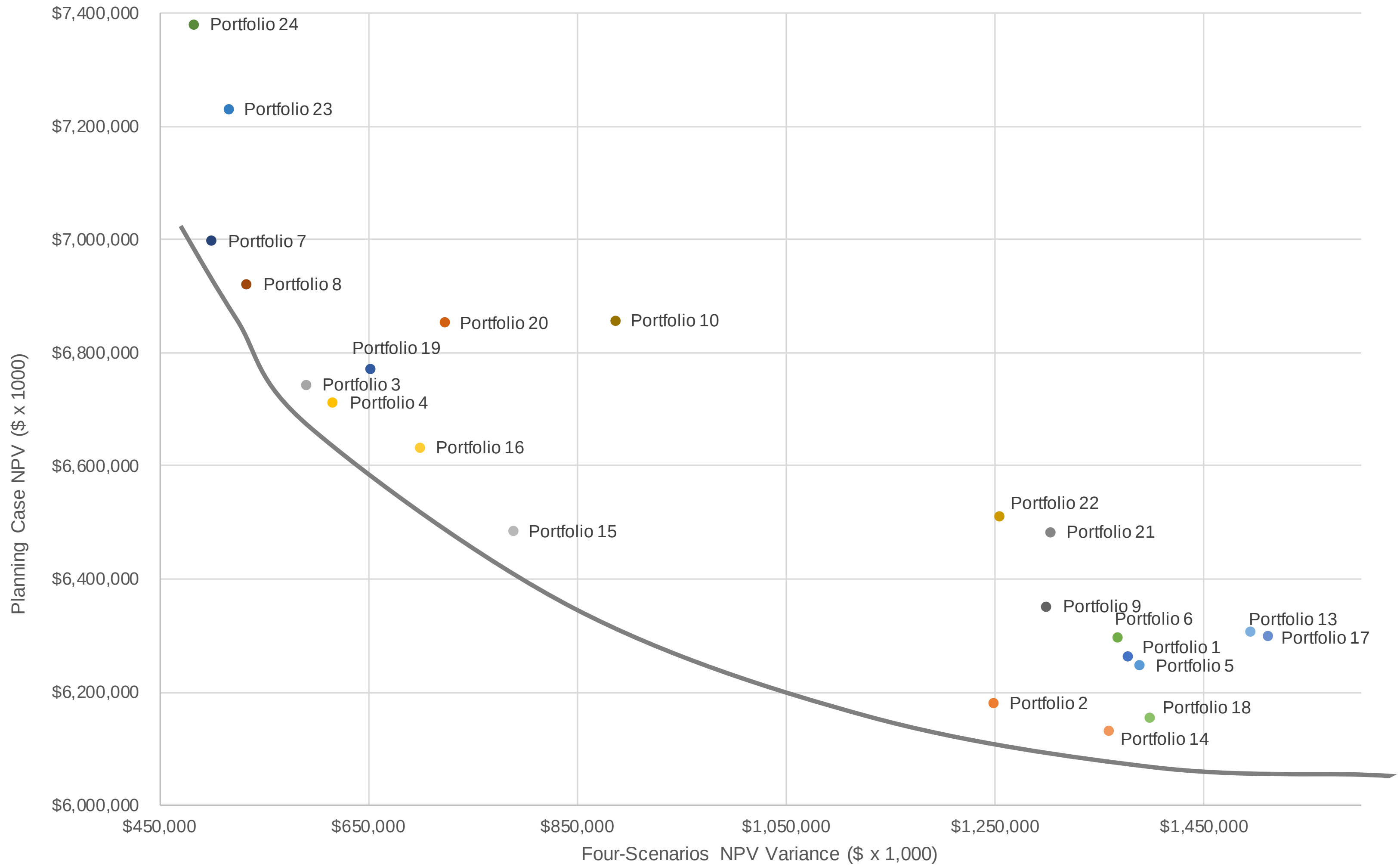

Figure 9.1 **NPV cost versus cost variance**

Based on these results, Idaho Power selected the following four WECC-optimized portfolios for manual adjustment with the objective of further reducing Idaho Power-specific portfolio costs:

- Portfolio 2 (Planning Gas, Planning Carbon, without B2H)
- Portfolio 4 (Planning Gas, High Carbon, without B2H)
- Portfolio 14 (Planning Gas, Planning Carbon, with B2H)
- Portfolio 16 (Planning Gas, High Carbon, with B2H).

Manually Built Portfolios

The manual adjustments to the selected four WECC-optimized portfolios specifically focused on evaluating Jim Bridger coal unit exit scenarios. In addition, a 15-percent planning margin was preserved while generally retaining the resource mix of the WECC-optimized portfolio. Table 9.4 shows the six selected Jim Bridger exit scenarios studied.

Table 9.4 Jim Bridger exit scenarios

Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6
2022	2022	2022	2022	2023	2024
2026	2026	2028	2026	2026	2026
2034	2028	2034	2028	2028	2028
2034	2034	2034	2030	2030	2030

The Jim Bridger exit scenarios (1), (2), (3), and (4) focused on evaluating exit scenarios for the second, third and fourth units, while scenarios (5) and (6) focused on evaluating the exit date associated with the first Jim Bridger unit. Scenarios (5) and (6) centered on portfolios developed under a planning natural gas, planning carbon future, or P2 and P14. Thus, the complete set of manually built portfolios consists of the following:

- P2 derived portfolios—P2(1), P2(2), P2(3), P2(4), P2(5), P2(6)
- P4 derived portfolios—P4(1), P4(2), P4(3), P4(4)
- P14 derived portfolios—P14(1), P14(2), P14 (3), P14 (4), P14 (5), P14 (6)
- P16 derived portfolios—P16(1), P16(2), P16(3), P16(4)

Manual adjustments yielded the portfolio cost changes for P2 (decreases and increases).

Table 9.5 Jim Bridger exit scenario cost changes for P2

Scenarios	1	2	3	4	5	6	Average
Planning Gas, Planning Carbon	-0.6%	-0.8%	-0.6%	-1.3%	-1.0%	-0.8%	-0.9%
High Gas, Planning Carbon	1.0%	1.9%	0.3%	2.6%	2.6%	2.5%	1.8%
Planning Gas, High Carbon	-2.4%	-4.6%	-1.9%	-5.5%	-5.3%	-5.2%	-4.1%
High Gas, High Carbon	-1.8%	-3.3%	-1.6%	-3.9%	-3.7%	-3.6%	-3.0%

Average	-0.9%	-1.7%	-1.0%	-2.0%	-1.9%	-1.8%	-1.5%

As demonstrated in the tables above, the LTCE model performed reasonably well in developing low cost portfolios for Idaho Power's service area. However, Idaho Power was able to further lower overall portfolio costs through the manual refinements detailed above. Based on these results, the company is confident that its preferred portfolio detailed in Chapter 10 achieves the low cost, low risk objective of the IRP.

Manual adjustments yielded the following portfolio cost changes for P4 (decreases and increases):

Table 9.6 Jim Bridger exit scenario cost changes for P4

Scenarios	1	2	3	4	Average
Planning Gas, Planning Carbon	-7.9%	-8.2%	-8.1%	-8.4%	-8.1%
High Gas, Planning Carbon	-1.7%	-1.3%	-2.2%	-0.4%	-1.4%
Planning Gas, High Carbon	2.7%	0.5%	2.6%	-0.2%	1.4%
High Gas, High Carbon	9.4%	7.3%	9.6%	6.7%	8.2%
Average	0.6%	-0.4%	0.5%	-0.6%	0.0%

Manual adjustments yielded the following portfolio cost changes for P14 (decreases and increases):

Table 9.7 Jim Bridger exit scenario cost changes for P14

Scenarios	1	2	3	4	5	6	Average
Planning Gas, Planning Carbon	-0.9%	-1.3%	-1.0%	-1.9%	-1.7%	-1.5%	-1.4%
High Gas, Planning Carbon	1.0%	1.4%	0.7%	1.7%	1.7%	1.6%	1.3%
Planning Gas, High Carbon	-1.7%	-3.8%	-1.3%	-5.4%	-5.2%	-5.1%	-3.7%
High Gas, High Carbon	-1.2%	-3.3%	-0.4%	-4.5%	-4.4%	-4.3%	-3.0%
Average	-0.7%	-1.8%	-0.5%	-2.5%	-2.4%	-2.3%	-1.7%

Manual adjustments yielded the following portfolio cost changes for P16 (decreases and increases):

Table 9.8 Jim Bridger exit scenario cost changes for P16

Scenarios	1	2	3	4	Average
Planning Gas, Planning Carbon	-8.5%	-9.0%	-8.4%	-9.6%	-8.9%
High Gas, Planning Carbon	-1.5%	-1.2%	-2.0%	-0.9%	-1.4%
Planning Gas, High Carbon	3.4%	1.2%	3.4%	-0.1%	2.0%
High Gas, High Carbon	10.8%	8.8%	11.0%	7.5%	9.5%
Average	1.1%	0.0%	1.0%	-0.8%	0.3%

The costs for the manually built portfolios under the four natural gas and carbon scenarios are provided in Table 9.9.

Table 9.9 2019 IRP manually built portfolios, NPV years 2019–2038 ($ x 1,000)

NPV ($ x 1000)	Planning Gas—Planning Carbon	High Gas—Planning Carbon	Planning Gas—High Carbon	High Gas—High Carbon
P2-1	$6,145,102	$7,121,558	$8,074,268	$9,316,639
P2-2	$6,129,872	$7,182,632	$7,892,135	$9,170,679
P2-3	$6,143,832	$7,069,053	$8,108,875	$9,330,234
P2-4	$6,103,118	$7,233,055	$7,816,128	$9,116,756
P14-1	$6,078,583	$7,153,869	$8,286,789	$9,608,551
P14-2	$6,050,117	$7,177,509	$8,109,147	$9,404,032
P14-3	$6,068,301	$7,129,172	$8,319,839	$9,679,042
P14-4	$6,012,329	$7,201,730	$7,970,850	$9,284,089
P4-1	$6,182,752	$7,064,347	$7,970,468	$9,134,728
P4-2	$6,160,188	$7,092,252	$7,801,005	$8,964,360
P4-3	$6,170,775	$7,025,150	$7,968,725	$9,154,217
P4-4	$6,151,167	$7,155,210	$7,751,893	$8,913,303
P16-1	$6,069,778	$7,095,243	$8,068,014	$9,437,687
P16-2	$6,033,966	$7,117,922	$7,896,872	$9,268,367
P16-3	$6,076,723	$7,063,064	$8,065,497	$9,451,679
P16-4	$5,996,478	$7,143,613	$7,791,783	$9,152,575
P2-5	$6,117,622	$7,233,779	$7,827,998	$9,129,774
P2-6	$6,129,786	$7,230,697	$7,840,382	$9,139,164
P14-5	$6,026,339	$7,200,864	$7,985,612	$9,291,816
P14-6	$6,040,012	$7,198,508	$7,999,308	$9,302,299

Under the Planning Gas and Planning Carbon scenario, P16(4) has the lowest NPV value of the 24 WECC-optimized portfolios at $5,996,478,000.

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).

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 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 0.65, which is based on historic values from 1997 through 2018.

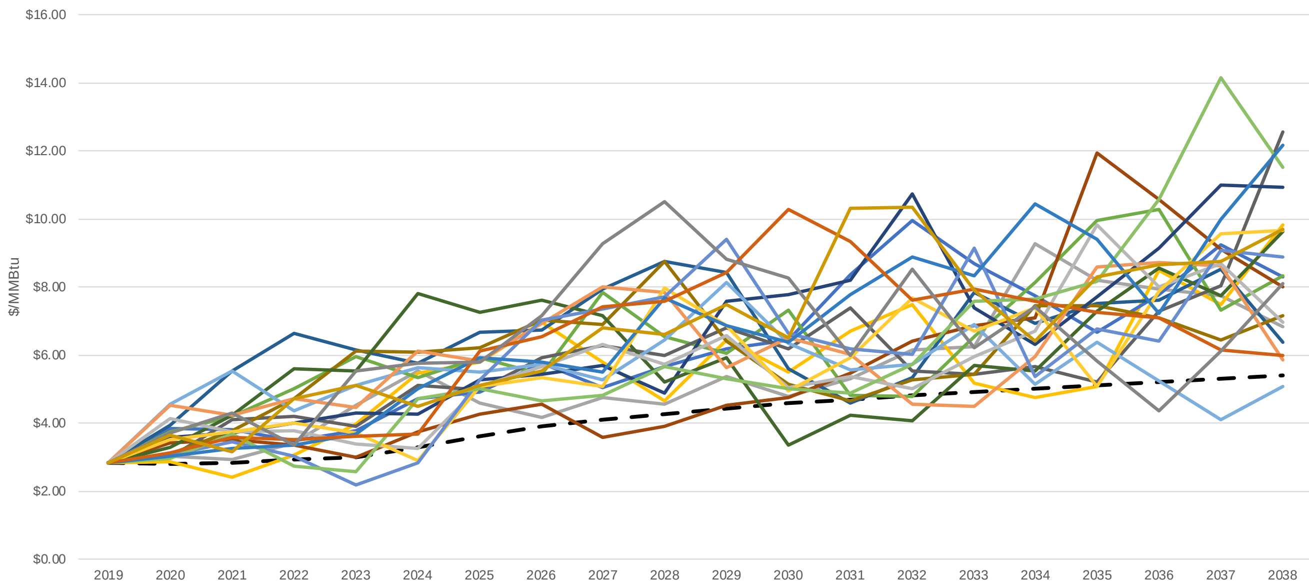

Figure 9.2 Natural gas sampling (Nominal $/MMBtu)

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

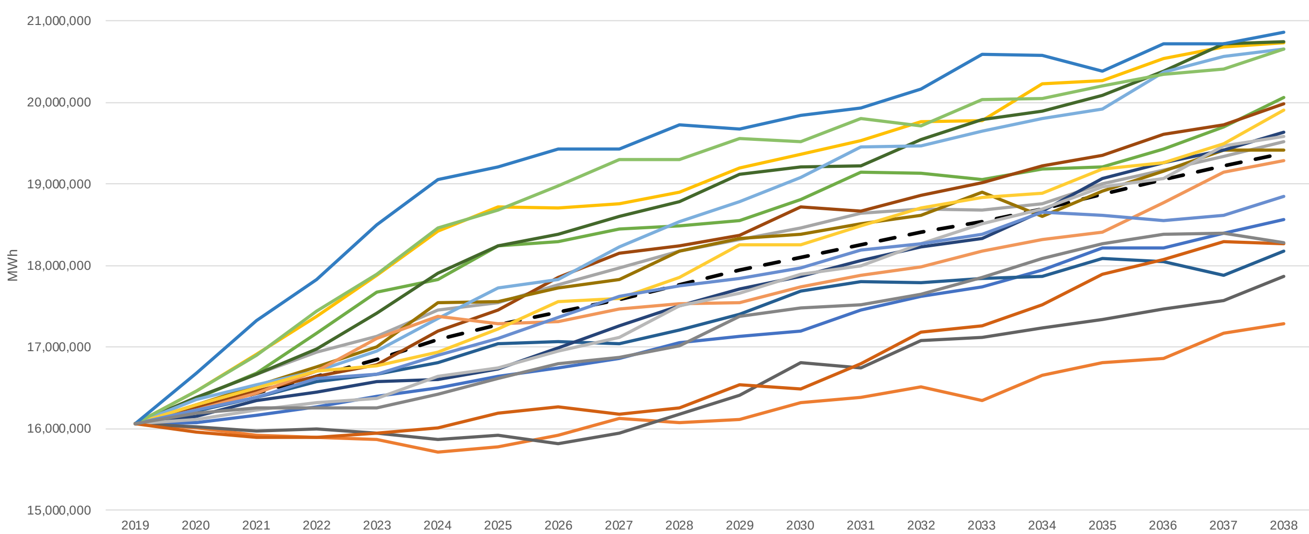

Figure 9.3 Customer load sampling (annual MWh)

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 0.80, which is based on historic values from 1971 through 2018.

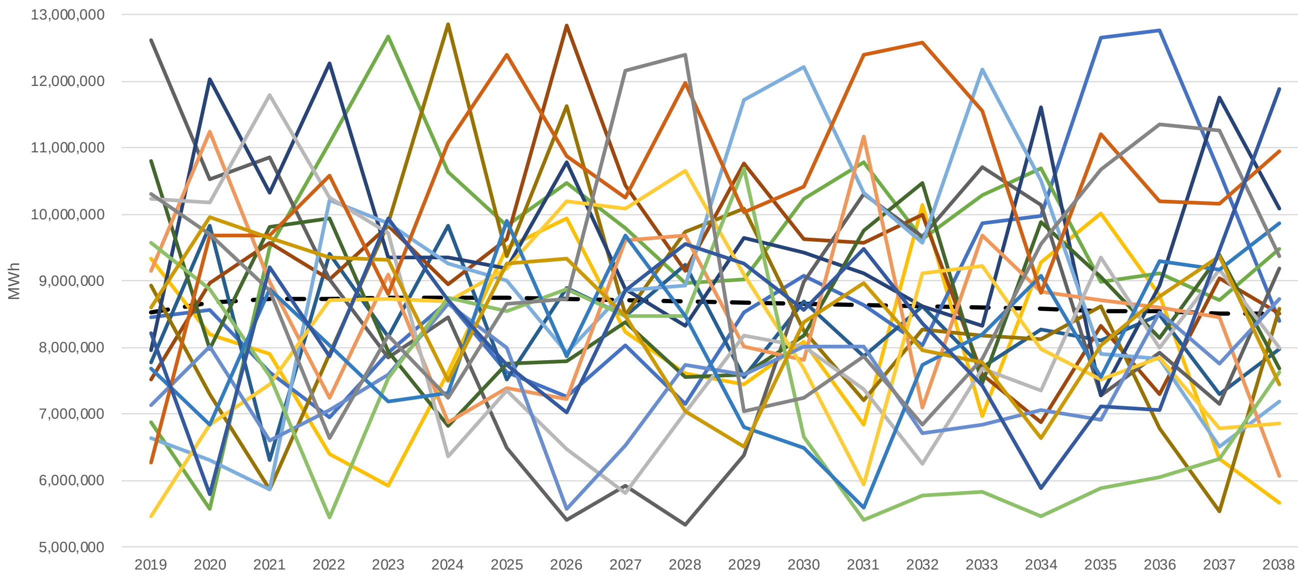

Figure 9.4 Hydro generation sampling (annual MWh)

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.

Idaho Power created a set of 20 iterations based on the three stochastic variables (hydro condition, load, and natural gas price). The 20 iterations were developed using a Latin Hypercube sampling rather than Monte Carlo. The Latin Hypercube design samples the distribution range with a relatively smaller sample size, allowing a reduction in simulation run times. Idaho Power then calculated the 20-year NPV portfolio cost for each of the 20 iterations for all 24 portfolios. The distribution of 20-year NPV portfolio costs for all 24 portfolios is shown in Figure 9.5.

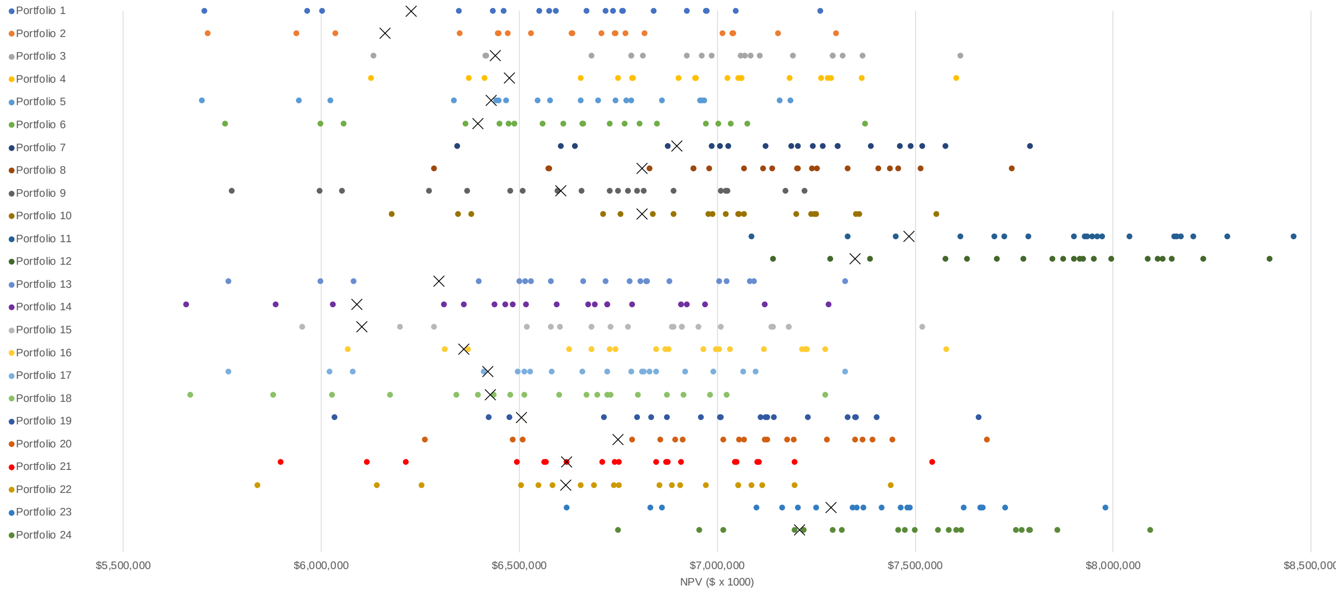

Figure 9.5 Portfolio stochastic analysis, total portfolio cost, NPV years 2019–2038 ($x 1,000)

The horizontal axis on Figure 9.5 represents the portfolio cost (NPV) in millions of dollars, and the 24 portfolios are represented by their designation on the vertical axis. Each portfolio has 20 dots for the 20 different stochastic iterations scattered across different NPV ranges. The Xs designate the Planning Gas Planning Carbon scenario that was performed for each portfolio.

The distribution of 20-year NPV portfolio costs for the set of 20 manually built portfolios is shown in Figure 9.6.

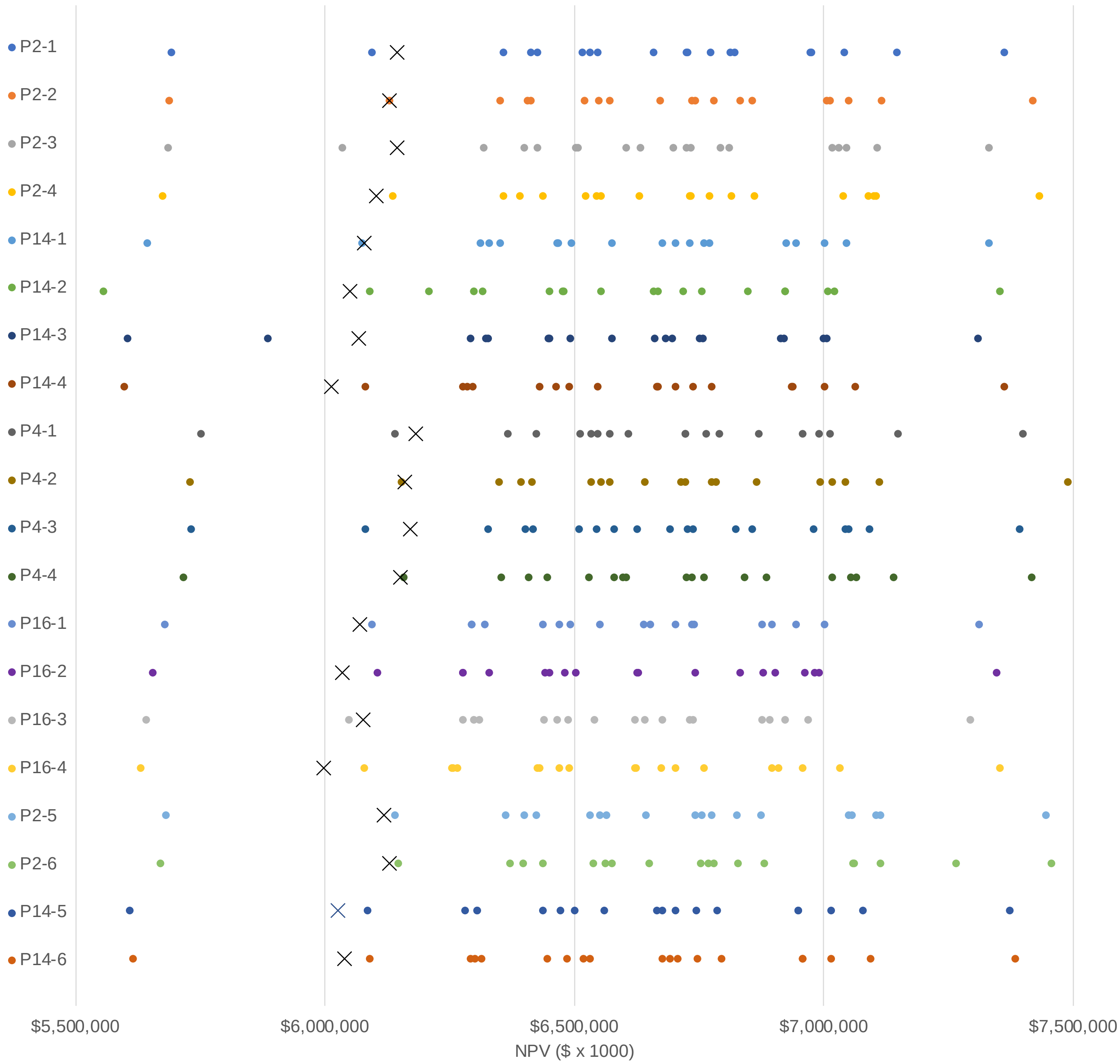

Figure 9.6 Manually built portfolio stochastic analysis, total portfolio cost, NPV years 2019–2038 ($x 1,000)

The stochastic risk analysis, coupled with the portfolio cost analysis, assesses the portfolios' relative exposure to significant cost drivers. The wide range of resulting portfolio costs evident in Table 9.3 and Figure 9.5 reflects the wide range of considered conditions for the cost drivers. The widely ranging costs are an indication that portfolio exposure to cost drivers is sufficiently evaluated. Further, the stochastic analysis suggests that changes in strong cost drivers do not shift the relative cost difference between portfolios significantly and thus does not favor one portfolio over another.

Portfolio Emission Results

The CO_2 emissions for all 24 portfolios were evaluated during the portfolio cost analysis. The results for all 24 portfolios is shown in Figure 9.6. Figure 9.6 is a stacked column that shows the year-to-year cumulative emissions for each portfolio's projected generating resources.

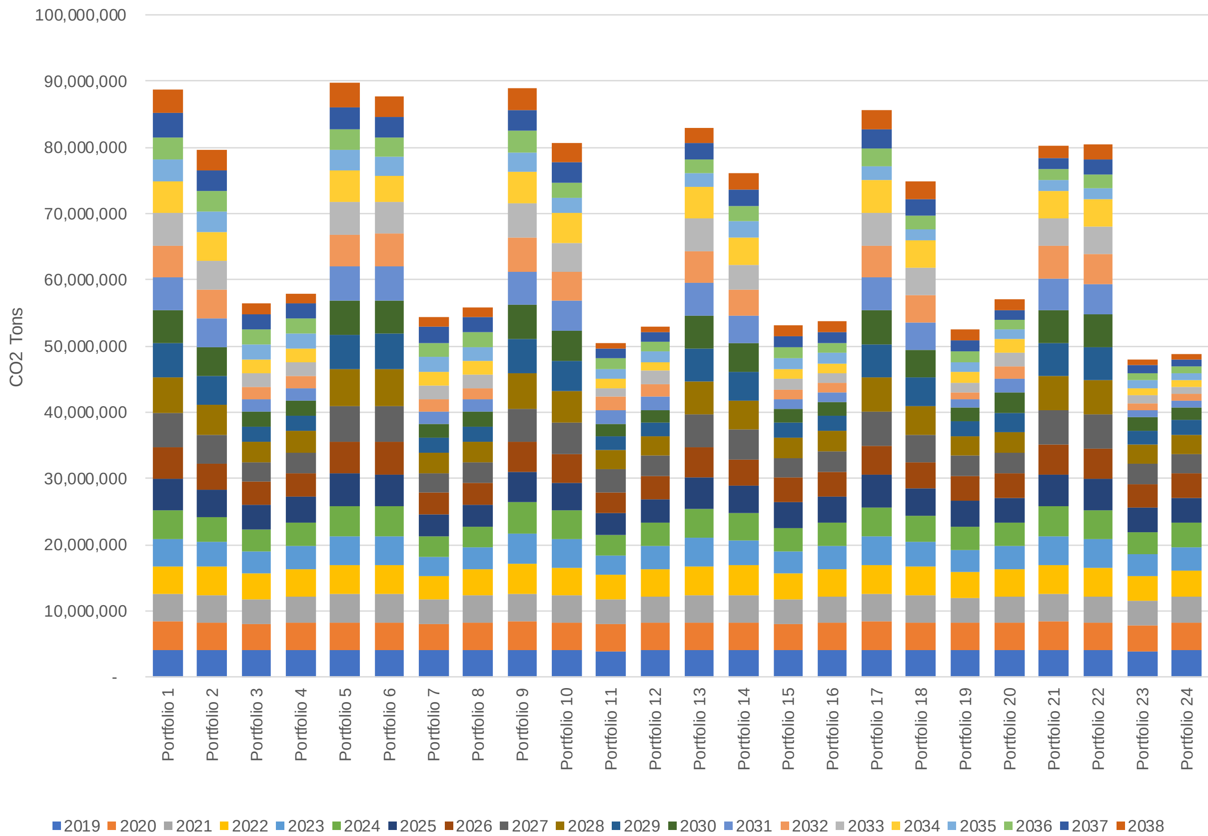

Figure 9.7 Estimated portfolio emissions from 2019–2038

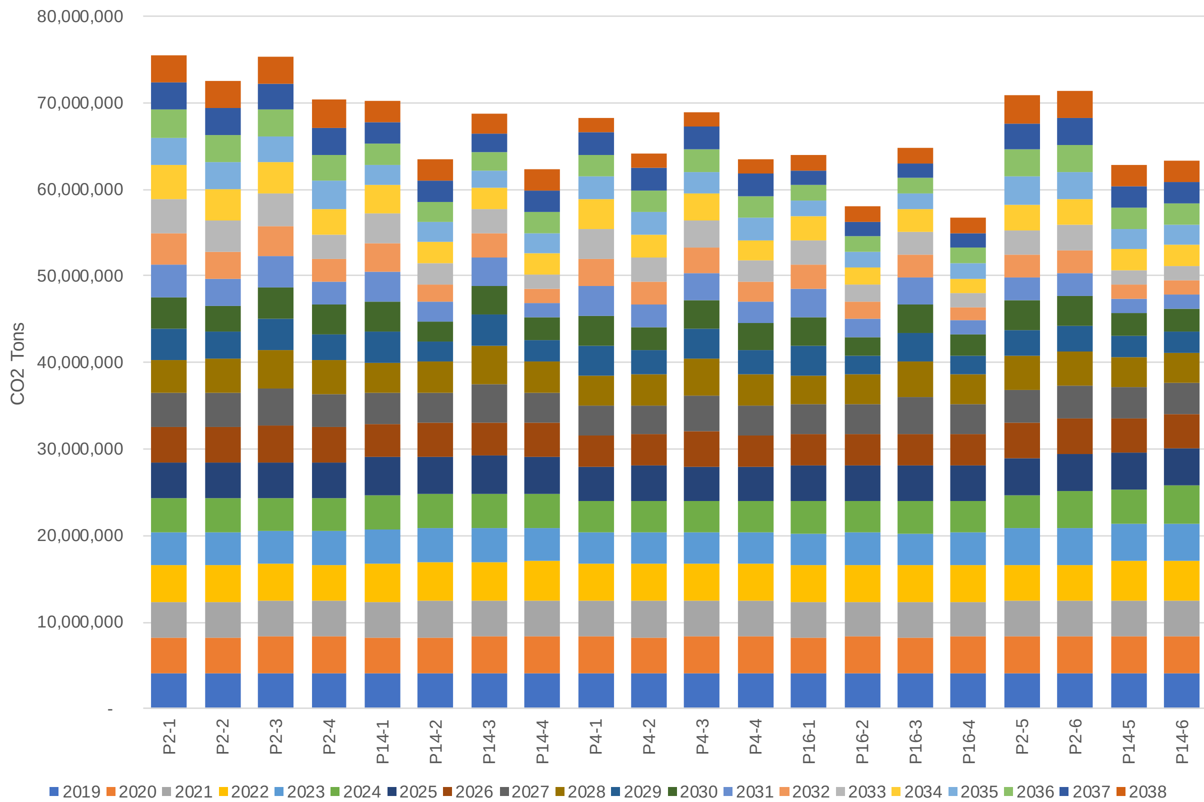

Figure 9.8 Estimated portfolio emissions from 2019–2038—manually built portfolios

Qualitative Risk Analysis

Major Qualitative Risks

- *Fuel Supply*—All generating and transmission resources require a supply of fuel to provide electricity. The different resource types have different fuel supply risks. Renewable resources rely on uncertain future weather conditions to provide the fuel be it wind, sun or water. Weather can be variable and difficult to forecast accurately. Thermal resources like coal and natural gas rely on infrastructure to produce and transport fuel by rail or pipeline and include mining or drilling facilities. Infrastructure has several risks when evaluating resources. Infrastructure is susceptible to outages from weather, mechanical failures, labor unrest, etc. Infrastructure can be limited in its existing availability to increase delivery of fuel to a geographic area that limits the amount of a new resources dependent on the capacity constrained infrastructure.

- *Fuel Price Volatility*—For plants needing purchased fuel, the fuel prices can be volatile and impact a plant's economics and usefulness to our customers both in the short and long term. Resources requiring purchased fuels like natural gas and coal have a higher exposure to fuel price risk.

- *Market Price Volatility*—Portfolios with resources that increase imports and/or exports heighten the exposure to a portfolio cost variability brought on by changes in market price and energy availability. Market price volatility is often dependent on regional fuel supply availability, weather, and fuel price risks. Resources, like wind and solar, that cannot respond to market price signals, expose the customer to higher short-term market price volatility.

- *Siting and Permitting*—All generating and transmission resources in the portfolios require siting and permitting for the resource to be successfully developed. The siting and permitting processes are uncertain and time-consuming, increasing the risk of unsuccessful or prolonged resource acquisition resulting in an adverse impact on economic planning and operations. Resources that require air and water permits or that have large geographic siting impacts have a higher risk. These include natural gas, nuclear, pumped storage and transmission resources, as well as solar and wind if the projects or associated transmission lines are sited on federal lands.

- *Technological Obsolescence*—Innovation in future generating resources may possess lower costs of power and have more desirable characteristics. Current technologies may become noncompetitive and strand investments which may adversely impact customers economically. Energy efficiency and demand response have the lowest exposure to technological obsolescence.

- *JB NOx Compliance Alternatives*—The negotiation with the Wyoming DEQ to extend the utilization of Jim Bridger units 1 and 2 without SCR investments to comply with the *Federal Clean Air Act* Regional Haze rules has not been completed. Without alternative compliance dates, these units have a risk of not being available for use in a portfolio after 2021 and 2022. Future reliance on these units may adversely impact customers and system reliability if a timely settlement is not obtained.

- *Partnerships*—Idaho Power is a partner in coal facilities and is currently jointly permitting and siting transmission facilities in anticipation of partner participation in construction and ownership of these transmission facilities. Coordinating partner need and timing of resource acquisition or retirement increases the risk of an Idaho Power timing or planning assumption not being met. Partner risk may adversely impact customers economically and adversely impact system reliability. B2H and Jim Bridger early unit retirement portfolios have the highest partner risk.

- *Federal and State Regulatory and Legislative*—There are currently many Federal and State rules governing power supply and planning. The risk of future rules altering the economics of new resources or the Idaho Power electrical system composition is an important consideration. Examples include carbon emission limits or adders, PURPA rules governing renewable PPAs, tax incentives and subsidies for renewable generation or other environmental or political reasons. New or changed rules could harm customers economically and impact system reliability.

- *Resource Off-Ramp Risks*—All resources require time to successfully approve, permit, site, engineer, procure, and build. Some resources have long development lead times incurring costs along the way, while others have relatively short lead times with much lower development costs. As previously mentioned, the pace of change in the power industry and electric markets is increasing. Consequently, resources that have a compelling story today may be less attractive in a not-so-distant future. The flexibility to not construct a resource when forecasted conditions change is an important consideration. Resources with long lead times and high development costs are susceptible to off-ramp risk. Likewise, early retirement and decommissioning of units limit flexibility to include the resource in the future. Reducing optionality in the selection of future resources may adversely affect customers economically.

Each resource possesses a set of qualitative risks that when combined over the study period, results in a unique and varied qualitative portfolio risk profile. Assessing a portfolio's aggregate risk profile is a subjective process weighing each component resource's characteristics in light of potential bad outcome for each resource and the portfolio of resources as a whole. Idaho Power evaluated each resource and resource portfolio against the qualitative risk components as described in the preceding section on the selection of the preferred portfolio.

Operational Considerations

- *System Regulation*—Maintaining a reliable system is a delicate balance requiring generation to match load on a sub-hourly time step. Over and under generation due to variability in load and generation requires a system to have dispatchable resources available at all times to maintain reliability and to comply with FERC rules and California Independent System Operator (CAISO) EIM flexibility requirements. Outages or other system conditions can impact the availability of dispatchable resources to provide flexibility. For example, in the spring, hydro conditions and flood control requirements can limit the availability of hydro units to ramp up or down in response to changing load and non-dispatchable generation. Not having hydro units available increases the reliance on baseload thermal resources like the Jim Bridger units as the primary flexible resources to maintain system reliability and comply with FERC and EIM rules. Increasing the variability of generation or reducing the availability of flexible resources can adversely impact the customer economically, Idaho Power's ability to comply with environmental requirements and the reliability of the system.

Frequency Duration Loss of Load Evaluation

Idaho Power used AURORA to evaluate the system loss of load using a frequency duration outage methodology for the 2019 IRP. The preferred portfolio was selected and analyzed in AURORA for 100 iterations in the year 2025. The year 2025 was selected because Idaho Power believes it will be a pivotal year. For the preferred portfolio, in 2025, there is not a large amount of excess resources on the system; the last resource built will have been a solar facility in 2023 and 2025 is a year before B2H going into service. The AURORA setup consists of generation resources and their associated forced (unexpected) outage rates. Given these outage rates, the model randomly allowed units to fail or return to service at any time during the simulation. The units selected for random outages were hydro units in the HCC, existing coal units on-line during 2025, and existing natural gas units. The setup also allowed transmission import lines to fail during the peak month of the study. The hydro generation was modified from the planning case 50 percent exceedance level to a more water restrictive 90 percent exceedance level. The demand forecast was also modified from the 50th percentile forecast to a higher load forecast of 95th percentile.

Ultimately, six unique loss-of-load events occurred out of the 100 iterations of year 2025. The results of the loss-of-load analysis show Idaho Power's system will exceed the industry standard of less than one event per 10 years and will be resource adequate through 2025, the year prior to the next major resource addition.

Regional Resource Adequacy

Northwest Seasonal Resource Availability Forecast

Idaho Power experiences its peak demand in late June or early July while the regional adequacy assessments suggest potential capacity deficits in late summer or winter. In the case of late summer, Idaho Power's demand has generally declined substantially; Idaho Power's irrigation customer demand begins to reduce starting in mid-July. For winter adequacy, Idaho Power generally has excess resource capacity to support the region.

The assessment of regional resource adequacy is useful in understanding the liquidity of regional wholesale electric markets. For the 2019 IRP, Idaho Power reviewed two recent assessments with characterizations of regional resource adequacy in the Pacific Northwest: the *Pacific Northwest Power Supply Adequacy Assessment for 2023* conducted by the NWPCC Resource Adequacy Advisory Committee (RAAC); and the *Pacific Northwest Loads and Resources Study* by the BPA (White Book). For illustrative purposes, Idaho Power also downloaded FERC 714 load data for the major Washington and Oregon Pacific Northwest entities to show the difference in regional demand between summer and winter.

The NWPCC RAAC uses a loss-of-load probability (LOLP) of 5 percent as a metric for assessing resource adequacy. The analytical information generated by each resource adequacy assessment is used by regional utilities in their individual IRPs.

The RAAC issued the *Pacific Northwest Power Supply Adequacy Assessment of 2023* report on June 14, 2018,[24] which reports the LOLP starting in operating year 2021 will exceed the acceptable 5 percent threshold and remain above through operating year 2023. Additional capacity needed to maintain adequacy is estimated to be on the order of 300 MW in 2021 with an additional need for 300 to 400 MW in 2022. The RAAC assessment includes all projected regional resource retirements and energy efficiency savings from code and federal standard changes but does not include approximately 1,340 MW of planned new resources that are not sited and licensed, and approximately 400 MW of projected demand response.

While it appears that regional utilities are well positioned to face the anticipated shortfall beginning in 2021, different manifestations of future uncertainties could significantly alter the outcome. For example, the results provided above are based on medium load growth. Reducing the 2023 load forecast by 2 percent results in an LOLP of under 5 percent.

From Idaho Power's standpoint, even with the conservative assumptions adopted in the *Pacific Northwest Power Supply Adequacy Assessment of 2023* report, the LOLP is zero for the critical

[24] NWPCC. Pacific Northwest power supply adequacy assessment for 2023. Document 2018-7. nwcouncil.org/sites/default/files/2018-7.pdf. Accessed April 25, 2017.

summer months (see Figure 9.7). The NWPCC analysis indicates that the region has a surplus in the summer; this is the reason that B2H works so well as a resource in Idaho Power's IRP.

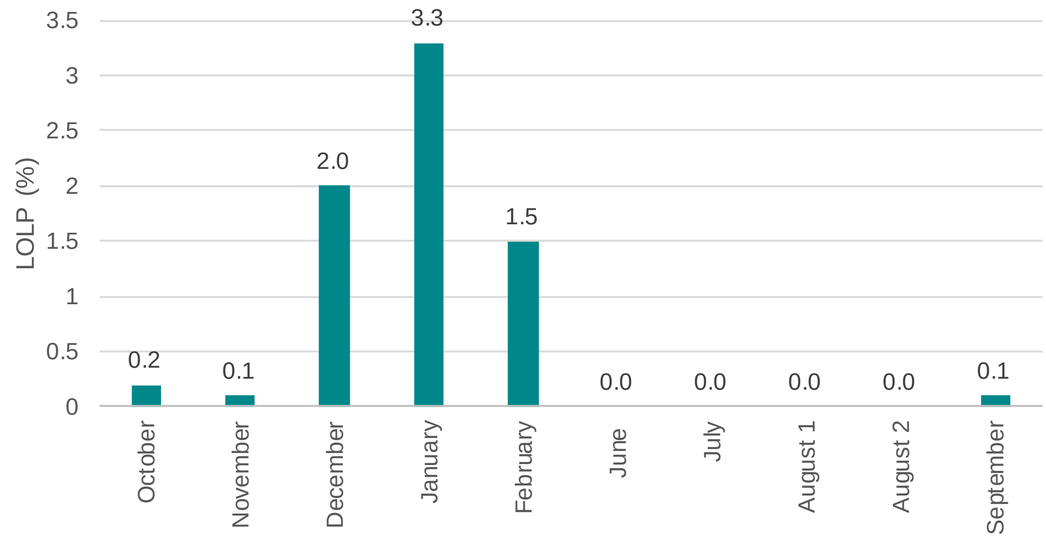

Figure 9.9 LOLP by month—Pacific Northwest Power Supply Adequacy Assessment of 2023

The most recent BPA adequacy assessment report was released in April 2019 and evaluates resource adequacy from 2020 through 2029.[25] BPA considers regional load diversity (i.e., winter- or summer-peaking utilities) and expected monthly production from the Pacific Northwest hydroelectric system under the critical case water year for the region (1937). Canadian resources are excluded from the BPA assessment. New regional generating projects are included when those resources begin operating or are under construction and have a scheduled on-line date. Similarly, retiring resources are removed on the date of the announced retirement. Resource forecasts for the region assume the retirement of the following coal projects over the study period:

Table 9.10 Coal retirement forecast

Resource	Retirement Date
Centralia 1	December 1, 2020
Boardman	January 1, 2021
Valmy 1	January 1, 2022
Colstrip 1	June 30, 2022
Colstrip 2	June 30, 2022
Centralia 2	December 1, 2025
Valmy 2	January 1, 2026

[25] BPA. 2018 Pacific Northwest loads and resources study (2018 white book). Technical Appendix, Volume 2: Capacity Analysis. bpa.gov/p/Generation/White-Book/wb/2018-WBK-Technical-Appendix-Volume-2-Capacity-Analysis-20190403.pdf. Accessed June 20, 2019

Figure 9.10 BPA white book PNW surplus/deficit one-hour capacity (1937 critical water year)

Finally, for illustrative purposes, Idaho Power downloaded peak load data reported through FERC Form 714 for the major Pacific Northwest entities in Washington and Oregon: Avista, BPA, Chelan County PUD, Douglas County PUD, Eugene Water and Electric Board, Grant County PUD, PGE, Puget Sound Energy, Seattle City Light, and Tacoma (PacifiCorp West data was unavailable). The coincident sum of these entities' total load is shown in Figure 9.9.

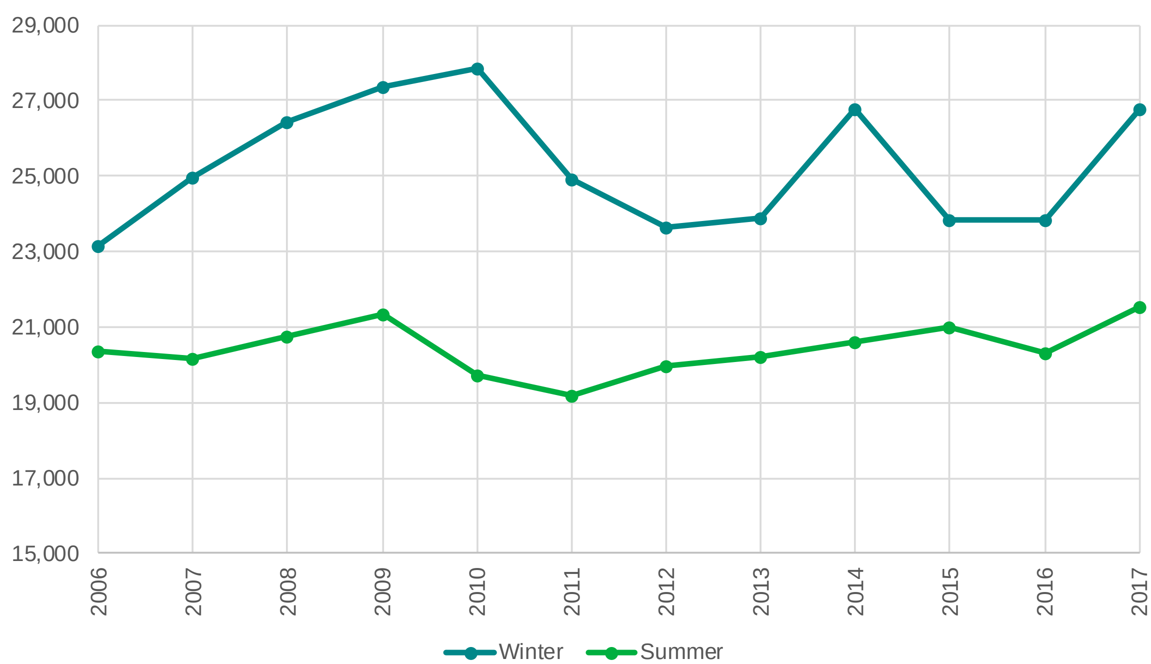

Figure 9.11 Peak coincident load data for most major Washington and Oregon utilities

Figure 9.9 illustrates a wide difference between historical winter and summer peaks for the Washington and Oregon area in the region. Other considerations, not depicted, include Canada's similar winter- to summer-peak load ratio, and the increased ability of the Pacific Northwest hydro system in late June through early July compared to the hydro system's capability in the winter.

Overall, each of these assessments includes very few new energy resources; any additions to the resource portfolio in the Pacific Northwest will only increase the surplus available during Idaho Power's peak operating periods. 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 such as the Western EIM and high penetrations of intermittent renewable resources.

10. Preferred Portfolio and Action Plan

Preferred Portfolio

The portfolio development process for Idaho Power's 2019 IRP evolved from a completely manual portfolio development process in past IRPs to using AURORA's LTCE capability for the 2019 IRP. The 24 resource portfolios developed are substantially different in their resource composition, driven by assumed future conditions for natural gas price and carbon cost. Once resource portfolios were generated, cost analysis for the 24 resource portfolios was performed under four different assumptions: planning case conditions for natural gas price and carbon cost, and also under higher-cost futures as shown in Table 10.1.

Table 10.1 AURORA hourly simulations

	Planning Carbon	High Carbon
Planning Gas	X	X
High Gas	X	X

The cost evaluation for different futures can be considered an examination of the quantitative risk associated with the higher-cost futures for natural gas and carbon prices, particularly on resource portfolios developed by AURORA assuming planning case conditions for natural gas price and carbon. The company also performed a stochastic risk analysis on the 24 resource portfolios, in which portfolio costs were computed for 20 different iterations for the studied stochastic risk variables: natural gas price, hydroelectric production, and system load. Collectively, between the portfolio cost evaluation under different natural gas/carbon cost assumptions and the numerous stochastic runs, risk is quantitatively captured over a wide range of potential futures.

To ensure the AURORA-produced WECC-optimized portfolios are aligned with the company's purpose of providing customers reliable and affordable energy, a subset of top-performing WECC portfolios was manually adjusted with the objective of further reducing portfolio costs specific to the Idaho Power system. The selected preferred portfolio for the 2019 IRP is a derivative of WECC-optimized portfolio P16, a portfolio developed under an assumption of planning case natural gas price forecast and high case carbon cost forecast. The preferred portfolio from the 2019 IRP is designated as P16(4), where the modifying numeral 4 represents the Jim Bridger exit scenario 4 (exit from units in 2022, 2026, 2028, and 2030). The preferred portfolio was further evaluated under an assumption of planning case natural gas price forecast and planning case carbon cost forecast, represented by P14(7).

Adjustments to P16 yielding the preferred portfolio are largely related to timing of resource actions, primarily in delaying the WECC-optimized portfolio's expansion of wind and solar resources in the 2020s. With the exception of wind resources, which declined by 300 MW nameplate over the IRP time horizon, the total nameplate capacity by resource type in the WECC-optimized portfolio is similar in quantity to its manually adjusted version. The preferred portfolio, particularly with the expansion of wind and solar resources in the 2030s, is considered to align well with Idaho Power's goal of 100 percent clean energy by 2045.

Resource actions of the preferred portfolio are provided in Table 10.2.

Table 10.2 Preferred portfolio additions and coal exits (MW)

	Gas	Wind	Solar	Battery	Demand Response	Coal Exit
2019						-127
2020						-58
2021						
2022			120			-177
2023						
2024						
2025						-133
2026						-180
2027						
2028						-174
2029			40	30		
2030	300					-177
2031					5	
2032			80	10	5	
2033			80	20	5	
2034			80	20	5	
2035	111				5	
2036					5	
2037			320			
2038		300	440			
Nameplate Total	**411**	**300**	**1,160**	**80**	**30**	**-1,026**
B2H (2026)	500					

Action Plan (2019–2026)

The 2019 IRP action plan is the culmination of the IRP process distilled down into actionable near-term items. The items identify milestones to successfully position Idaho Power to provide reliable, economic and environmentally sound service to our customers into the future. The current regional electric market, regulatory environment, pace of technological change and Idaho Power's recently announced goal of 100 percent clean energy by 2045 make the 2019 action plan especially germane.

The action plan associated with the preferred portfolio is driven by its core resource actions through the mid-2020s. These core resource actions include:

- 120 MW of added solar PV capacity (2022)
- Exit from three coal-fired generating units by year-end 2022, and from five coal-fired generating units (total) by year-end 2026
- B2H on-line in 2026

The action plan is heavily influenced by the above resource actions and portfolio attributes, which are discussed briefly in the following sections.

120 MW Solar PV Capacity (2022)

The preferred portfolio includes the addition of 120 MW of solar PV capacity in 2022. This capacity is associated with a PPA Idaho Power signed to purchase output from the 120 MW Jackpot Solar facility having a projected commercial on-line date of December 2022. The PPA for Jackpot Solar was approved by the IPUC on December 24, 2019.

Exit from Coal-Fired Generating Capacity

The preferred portfolio includes Idaho Power's exit from its share of North Valmy Unit 1 by year-end 2019, Boardman by year-end 2020, a Jim Bridger unit during 2022, North Valmy Unit 2 by year-end 2025, and a second Jim Bridger unit during 2026. The achievement of these coal-unit exits is expected to require substantial coordination with unit co-owners, regulators, and other stakeholders. The company also recognizes the need to ensure system reliability is not jeopardized by coal-unit exits, and considers B2H as a necessary resource in enabling the proposed coal-unit exits.

B2H On-line in 2026

The preferred portfolio includes the B2H transmission line with an on-line date during 2026. Continued permitting and construction activities are included in the IRP action plan.

Demand Response

The company acknowledges that under the amended preferred portfolio, some demand response was shifted into future years outside of the action plan window in comparison to the 2019 IRP preferred portfolio filed in June 2019. The company examined the cost associated with accelerating demand response within the amended preferred portfolio and found accelerating demand response added nearly $900,000 to the preferred portfolio NPV. In moving forward with the amended preferred portfolio as least-cost, least-risk, the company acknowledges the benefit of demand response and will continue to evaluate the cost and risk associated with accelerating demand response to earlier years.

Action Plan (2019–2026)

Table 10.3 Action Plan (2019–2026)

Year	Action
2019–2022	Plan and coordinate with PacifiCorp and regulators for early exits from Jim Bridger units. Target dates for early exits are one unit during 2022 and a second unit during 2026. Timing of exit from second unit coincides with the need for a resource addition.
2019-2022	Incorporate solar hosting capacity into the customer-owned generation forecasts for the 2021 IRP.
2019	Jackpot Solar PPA regulatory approval*—on-line December 2022
2019	Exit Valmy Unit 1 by December 31, 2019.*
2019–2021	Conduct ongoing B2H permitting activities. Negotiate and execute B2H partner construction agreement(s).
2019–2026	Conduct preliminary construction activities, acquire long-lead materials, and construct the B2H project.
2019–2020	Monitor VER variability and system reliability needs, and study projected effects of additions of 120 MW of PV solar (Jackpot Solar) and early exit of Bridger units.
2020	Exit Boardman December 31, 2020.
2020	Bridger Unit 1 and Unit 2 Regional Haze Reassessment finalized.
2020	Conduct a VER Integration Study.
2021–2022	Continue to evaluate and coordinate with PacifiCorp for timing of exit/closure of remaining Jim Bridger units.
2022	Subject to coordination with PacifiCorp, exit Jim Bridger unit (as yet undesignated) by December 31, 2022.
2022	Jackpot Solar 120 MW on-line December 2022.
2023–2026	Procure or construct resources resulting from RFP (if needed).
2025	Exit Valmy Unit 2 by December 31, 2025.
2026	Subject to coordination with PacifiCorp, exit Jim Bridger unit (as yet undesignated) by December 31, 2026. Timing of the exit from the second Jim Bridger unit is tied to the need for a resource addition (B2H).

Conclusion

The 2019 IRP provides guidance for Idaho Power as its portfolio of resources evolves over the coming years. The B2H transmission line continues in the 2019 IRP analysis to be a top-performing resource alternative providing Idaho Power access to clean and low-cost energy in the Pacific Northwest wholesale electric market. From a regional perspective, the B2H transmission line, and high-voltage transmission in general, is a critical part to the achievement of clean energy objectives, including Idaho Power's 2045 clean energy goal.

Idaho Power linemen install upgrades.

The cost competitiveness of PV solar is another notable theme of the 2019 IRP. The preferred portfolio for the 2019 IRP includes a PPA to purchase output from 120 MW of PV solar projected on-line in December 2022. Idaho Power's IRP analysis indicates this contract allows the cost-competitive acquisition of PV solar energy, and further positions the company in its achievement of long-term clean energy goals.

The 2019 IRP indicates favorable economics associated with Idaho Power's exit from five of seven coal-fired generating units by the end of 2026, and exit from the remaining two units at the Jim Bridger facility by the end of the 2020s. Idaho Power views this strategy as consistent with its long-term clean energy goals and transition from coal-fired generation, and further sees the B2H transmission line as a resource critical to enabling the exit from coal-fired generation.

Idaho Power recognizes its obligation to reliably deliver affordable electricity to customers cannot be compromised as it strives to achieve clean energy goals and emphasizes the need to continue to evaluate the coal-fired units' value in providing flexible capacity necessary to successfully integrate high penetration of VERs. Furthermore, the company recognizes the evaluation of flexible capacity, and the possibility of flexibility deficiencies arising because of coal-unit exit, may require the preferred portfolio's flexible capacity resources to be on-line sooner than planned.

Idaho Power strongly values public involvement in the planning process. Idaho Power thanks the IRPAC members and the public for their contributions to the 2019 IRP. The IRPAC discussed many technical aspects of the 2019 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 2021. The energy industry is expected to continue to undergo substantial transformation over the coming years, and new challenges and questions will be encountered in the 2021 IRP. Idaho Power will continue to monitor trends in the energy industry and adjust as necessary in the 2021 IRP.

IDAHO POWER®
An IDACORP Company

INTEGRATED RESOURCE PLAN

2019

AMENDED • JANUARY • 2020

APPENDIX C: TECHNICAL REPORT

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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TABLE OF CONTENTS

INTRODUCTION

Appendix C–Technical Appendix contains supporting data and explanatory materials used to develop Idaho Power's *2019 Integrated Resource Plan* (IRP).

The main document, the IRP, contains a full narrative of Idaho Power's resource planning process. Additional information regarding the 2019 IRP sales and load forecast is contained in *Appendix A–Sales and Load Forecast*, details on Idaho Power's demand-side management efforts are explained in *Appendix B–Demand-Side Management 2018 Annual Report*, and supplemental information on Boardman to Hemingway (B2H) transmission is provided in *Appendix D–B2H Supplement.* The IRP, including the four appendices, was filed with the Idaho and Oregon public utility commissions in June 2019. Amendments to the IRP, *Appendix C—Technical Appendix* and *Appendix D—B2H Supplement* were filed with the Idaho and Oregon public utility commissions in January 2020.

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 10 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
St. Luke's Medical	Mark Eriksen
Public-Interest Representatives	
Boise Metro Chamber of Commerce	Ray Stark
Boise State University Energy Policy Institute	Kathleen Araujo
City of Boise	Steve Burgos
Idaho Conservation League	Ben Otto
Idaho Legislature	Representative Robert Anderst
Idaho Office of Energy and Mineral Resources	John Chatburn
Idaho Sierra Club	Mike Heckler
Idaho Technology Council	Jay Larsen
Idaho Water Resource Board	Roger Chase
Northwest Power and Conservation Council	Ben Kujala
Oil and Gas Industry Advisor	David Hawk
Oregon State University—Malheur Experiment Station	Clint Shock
Snake River Alliance	Chad Worth
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
2018	Thursday, September 13	Welcome and opening remarks 2017 IRP Review IRP overview and process road map Carbon Outlook Natural gas forecast
2018	Thursday, October 11	IRP process review Load forecast Streamflow forecast Hydro production forecast Hydro climate change modeling results PURPA forecast and assumptions Natural gas price
2018	Thursday, November 8	Regional transmission overview Boardman to Hemingway transmission update Storage outlook Resource cost assumptions IPC planning criteria capacity, energy, and flexibility—2017 IRP to 2019 IRP Coal unit futures
2018	Thursday, December 13	AURORA model workshop Energy efficiency potential study Regional resource adequacy Solar capacity credit Distributed resources: value to the transmission and distribution system
2019	Thursday, January 10	T&D deferral benefit Demand response Energy imbalance market (EIM) Reserve requirements Capacity expansion modeling update Updated resource cost assumptions
2019	Thursday, March 14	AURORA LTCE portfolio results Sensitivities to planning assumptions Stochastic elements Hells Canyon Complex relicensing Cloud seeding
2019	Thursday, April 11	Idaho Power clean energy goal AURORA results update Qualitative risk assessment Preliminary preferred portfolio recommendation
2019	Thursday, May 9	Loss of load analysis Power system operations: summer readiness IPC sustainability programs 2019 IRP action plan

Meeting Dates		Agenda Items
2019	Thursday, September 18	Review Initial Conclusions Cause for Supplemental Analysis Modeling Updates Next Steps
2019	Friday, December 6	Discount Rate Change Other Updates and Modeling Assumptions Modeling Results 2019 Preferred Portfolio and Action Plan

SALES AND LOAD FORECAST DATA

50th Percentile Annual Forecast Growth Rates

	2019–2024	2019–2029	2019–2038
Sales			
Residential Sales	1.17%	1.15%	1.13%
Commercial Sales	1.17%	1.21%	1.15%
Irrigation Sales	0.78%	0.76%	0.75%
Industrial Sales	1.09%	0.82%	0.56%
Additional Firm Sales	3.68%	2.06%	1.18%
System Sales	1.27%	1.12%	1.00%
Total Sales	1.27%	1.12%	1.00%
Loads			
Residential Load	1.11%	1.15%	1.13%
Commercial Load	1.12%	1.21%	1.14%
Irrigation Load	0.72%	0.76%	0.75%
Industrial Load	1.02%	0.81%	0.55%
Additional Firm Sales	3.68%	2.06%	1.18%
System Load Losses	1.12%	1.10%	1.02%
System Load	1.21%	1.12%	1.00%
Total Load	1.21%	1.12%	1.00%
Peaks			
System Peak	1.35%	1.27%	1.18%
Total Peak	1.35%	1.27%	1.18%
Winter Peak	1.14%	1.03%	0.95%
Summer Peak	1.35%	1.27%	1.18%
Customers			
Residential Customers	2.12%	1.93%	1.68%
Commercial Customers	1.97%	1.80%	1.67%
Irrigation Customers	1.32%	1.28%	1.21%
Industrial Customers	0.53%	0.43%	0.49%

Expected-Case Load Forecast

2019 Monthly Summary1	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	831	711	575	502	442	530	649	605	474	487	625	786
Commercial	505	482	443	429	437	482	501	509	463	454	462	513
Irrigation	3	3	8	119	324	624	631	546	316	67	5	3
Industrial	274	280	281	270	274	294	288	296	288	291	283	282
Additional Firm	114	114	108	104	104	95	105	107	111	112	118	120
Loss	147	134	117	119	134	176	190	179	139	116	124	144
System Load	**1,874**	**1,724**	**1,532**	**1,543**	**1,714**	**2,201**	**2,363**	**2,243**	**1,791**	**1,527**	**1,617**	**1,848**
Light Load	1,750	1,587	1,406	1,398	1,558	1,991	2,133	1,986	1,616	1,368	1,489	1,712
Heavy Load	1,972	1,826	1,631	1,648	1,837	2,369	2,545	2,429	1,945	1,642	1,720	1,966
Total Load	**1,874**	**1,724**	**1,532**	**1,543**	**1,714**	**2,201**	**2,363**	**2,243**	**1,791**	**1,527**	**1,617**	**1,848**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,502	2,277	2,030	2,000	2,675	3,470	3,610	3,354	2,795	2,070	2,277	2,549
System Peak Load (1 hour) 95th Percentile	2,535	2,361	2,075	2,015	2,695	3,511	3,634	3,391	2,812	2,087	2,319	2,636

2020 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	842	695	581	506	445	535	657	613	478	490	629	794
Commercial	513	472	448	434	442	488	508	516	469	459	467	518
Irrigation	3	2	8	120	328	630	638	551	319	68	5	3
Industrial	278	274	284	273	277	298	292	300	292	294	287	287
Additional Firm	117	112	110	106	106	97	106	109	113	114	120	123
Loss	149	131	119	120	135	178	192	181	141	117	125	146
System Load	**1,901**	**1,687**	**1,549**	**1,560**	**1,733**	**2,226**	**2,393**	**2,271**	**1,810**	**1,542**	**1,633**	**1,871**
Light Load	1,775	1,553	1,422	1,414	1,575	2,013	2,160	2,011	1,633	1,382	1,504	1,733
Heavy Load	2,000	1,785	1,649	1,667	1,869	2,381	2,577	2,476	1,952	1,658	1,747	1,980
Total Load	**1,901**	**1,687**	**1,549**	**1,560**	**1,733**	**2,226**	**2,393**	**2,271**	**1,810**	**1,542**	**1,633**	**1,871**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,522	2,298	2,034	2,017	2,693	3,527	3,659	3,407	2,829	2,087	2,295	2,581
System Peak Load (1 hour) 95th Percentile	2,555	2,382	2,080	2,032	2,713	3,568	3,683	3,444	2,846	2,105	2,337	2,668

[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.

2021 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	853	730	586	510	448	540	665	620	481	492	633	802
Commercial	518	493	451	439	446	493	513	522	473	462	471	524
Irrigation	3	3	8	121	330	634	642	555	321	68	5	3
Industrial	282	288	288	277	281	302	296	304	296	299	291	289
Additional Firm	121	120	114	110	110	101	111	113	117	119	125	127
Loss	151	137	120	121	136	180	194	183	142	118	126	148
System Load	**1,928**	**1,771**	**1,567**	**1,577**	**1,751**	**2,249**	**2,421**	**2,298**	**1,829**	**1,558**	**1,651**	**1,893**
Light Load	1,801	1,631	1,439	1,430	1,592	2,034	2,185	2,035	1,650	1,396	1,520	1,754
Heavy Load	2,038	1,876	1,660	1,685	1,888	2,406	2,607	2,506	1,973	1,686	1,756	2,004
Total Load	**1,928**	**1,771**	**1,567**	**1,577**	**1,751**	**2,249**	**2,421**	**2,298**	**1,829**	**1,558**	**1,651**	**1,893**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,555	2,322	2,060	2,032	2,710	3,558	3,707	3,450	2,860	2,105	2,312	2,597
System Peak Load (1 hour) 95th Percentile	2,588	2,406	2,106	2,047	2,730	3,600	3,731	3,487	2,877	2,123	2,354	2,684

2022 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	864	738	590	513	451	545	674	629	486	496	639	812
Commercial	527	500	457	445	452	499	521	530	478	468	477	531
Irrigation	3	3	8	122	333	640	647	560	324	69	5	3
Industrial	284	290	291	280	283	305	299	307	298	301	293	292
Additional Firm	125	124	118	114	114	105	114	117	121	123	129	131
Loss	153	139	121	123	138	182	197	185	144	120	128	149
System Load	**1,956**	**1,795**	**1,585**	**1,595**	**1,770**	**2,275**	**2,453**	**2,329**	**1,852**	**1,577**	**1,671**	**1,919**
Light Load	1,826	1,653	1,455	1,446	1,609	2,058	2,214	2,062	1,670	1,413	1,538	1,777
Heavy Load	2,067	1,901	1,679	1,704	1,909	2,434	2,659	2,522	1,997	1,706	1,778	2,031
Total Load	**1,956**	**1,795**	**1,585**	**1,595**	**1,770**	**2,275**	**2,453**	**2,329**	**1,852**	**1,577**	**1,671**	**1,919**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,554	2,346	2,080	2,048	2,728	3,609	3,757	3,506	2,897	2,125	2,332	2,625
System Peak Load (1 hour) 95th Percentile	2,617	2,430	2,125	2,063	2,749	3,650	3,782	3,544	2,914	2,143	2,374	2,712

2023 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	878	749	598	519	457	554	687	640	492	501	646	822
Commercial	534	506	462	450	457	505	528	537	483	473	482	537
Irrigation	3	3	8	123	336	645	653	565	326	69	5	3
Industrial	287	293	293	282	286	308	302	310	301	304	296	295
Additional Firm	127	126	120	116	116	107	117	120	124	125	131	134
Loss	156	141	123	124	139	184	199	188	145	121	129	151
System Load	**1,984**	**1,819**	**1,604**	**1,614**	**1,791**	**2,302**	**2,485**	**2,359**	**1,872**	**1,593**	**1,689**	**1,942**
Light Load	1,852	1,675	1,472	1,463	1,627	2,083	2,243	2,089	1,689	1,428	1,555	1,799
Heavy Load	2,097	1,927	1,699	1,735	1,919	2,463	2,693	2,555	2,019	1,724	1,797	2,065
Total Load	**1,984**	**1,819**	**1,604**	**1,614**	**1,791**	**2,302**	**2,485**	**2,359**	**1,872**	**1,593**	**1,689**	**1,942**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,611	2,369	2,097	2,064	2,747	3,654	3,808	3,559	2,932	2,144	2,350	2,648
System Peak Load (1 hour) 95th Percentile	2,644	2,453	2,143	2,079	2,767	3,696	3,832	3,596	2,949	2,161	2,392	2,735

2024 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	891	734	605	525	462	562	698	650	498	505	652	832
Commercial	540	494	466	455	461	510	534	544	488	477	486	543
Irrigation	3	3	8	124	338	650	658	569	329	70	5	3
Industrial	290	286	296	285	289	311	304	313	304	307	299	297
Additional Firm	138	132	130	124	124	115	124	127	131	134	141	145
Loss	158	138	124	126	141	186	202	190	147	122	131	153
System Load	**2,020**	**1,787**	**1,629**	**1,638**	**1,815**	**2,334**	**2,521**	**2,393**	**1,897**	**1,615**	**1,714**	**1,973**
Light Load	1,886	1,646	1,495	1,484	1,650	2,111	2,275	2,119	1,711	1,447	1,578	1,827
Heavy Load	2,125	1,892	1,735	1,750	1,945	2,512	2,715	2,592	2,059	1,736	1,824	2,098
Total Load	**2,020**	**1,787**	**1,629**	**1,638**	**1,815**	**2,334**	**2,521**	**2,393**	**1,897**	**1,615**	**1,714**	**1,973**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,650	2,400	2,125	2,087	2,771	3,706	3,863	3,617	2,971	2,167	2,376	2,682
System Peak Load (1 hour) 95th Percentile	2,683	2,484	2,171	2,102	2,791	3,748	3,887	3,655	2,988	2,185	2,418	2,768

2025 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	903	771	611	530	467	569	710	660	503	509	657	840
Commercial	548	519	472	461	467	517	541	551	493	482	492	550
Irrigation	3	3	8	125	341	655	663	573	331	70	5	3
Industrial	292	298	298	287	291	313	307	315	306	309	301	298
Additional Firm	140	139	132	126	125	116	125	128	132	135	143	147
Loss	160	145	125	127	142	188	204	192	148	123	132	155
System Load	**2,047**	**1,875**	**1,646**	**1,654**	**1,833**	**2,358**	**2,550**	**2,421**	**1,915**	**1,629**	**1,731**	**1,993**
Light Load	1,911	1,727	1,511	1,499	1,666	2,133	2,302	2,144	1,727	1,460	1,593	1,846
Heavy Load	2,154	1,986	1,753	1,768	1,965	2,538	2,746	2,640	2,065	1,752	1,851	2,109
Total Load	**2,047**	**1,875**	**1,646**	**1,654**	**1,833**	**2,358**	**2,550**	**2,421**	**1,915**	**1,629**	**1,731**	**1,993**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,679	2,426	2,144	2,101	2,787	3,753	3,911	3,670	3,003	2,184	2,392	2,705
System Peak Load (1 hour) 95th Percentile	2,711	2,510	2,190	2,116	2,808	3,795	3,935	3,707	3,020	2,201	2,435	2,791

2026 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	914	779	616	534	471	575	719	669	507	511	661	847
Commercial	556	526	477	466	472	523	549	559	499	487	497	556
Irrigation	3	3	8	126	343	660	668	578	334	71	5	3
Industrial	293	300	300	288	292	315	308	317	308	311	303	300
Additional Firm	141	140	132	126	126	117	126	129	133	136	144	148
Loss	162	147	126	128	144	190	207	195	150	124	133	156
System Load	**2,069**	**1,893**	**1,660**	**1,668**	**1,848**	**2,380**	**2,577**	**2,446**	**1,930**	**1,641**	**1,743**	**2,011**
Light Load	1,932	1,744	1,523	1,512	1,680	2,152	2,325	2,165	1,741	1,470	1,605	1,862
Heavy Load	2,177	2,006	1,767	1,782	1,993	2,545	2,775	2,667	2,082	1,764	1,865	2,128
Total Load	**2,069**	**1,893**	**1,660**	**1,668**	**1,848**	**2,380**	**2,577**	**2,446**	**1,930**	**1,641**	**1,743**	**2,011**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,699	2,443	2,154	2,113	2,801	3,786	3,956	3,712	3,030	2,196	2,404	2,717
System Peak Load (1 hour) 95th Percentile	2,732	2,527	2,200	2,128	2,821	3,827	3,980	3,749	3,047	2,214	2,446	2,804

2027 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	924	787	621	537	474	581	728	677	511	513	664	856
Commercial	564	532	482	472	477	529	556	567	504	492	503	563
Irrigation	3	3	8	127	346	666	674	583	337	72	5	3
Industrial	295	301	302	290	294	317	310	319	310	313	305	302
Additional Firm	141	140	132	126	126	117	126	129	133	136	144	148
Loss	164	148	128	129	145	191	209	197	151	125	134	158
System Load	**2,091**	**1,912**	**1,673**	**1,681**	**1,863**	**2,401**	**2,603**	**2,470**	**1,945**	**1,651**	**1,755**	**2,030**
Light Load	1,952	1,761	1,535	1,524	1,693	2,172	2,349	2,187	1,755	1,480	1,616	1,880
Heavy Load	2,210	2,025	1,772	1,796	2,009	2,568	2,803	2,693	2,098	1,787	1,867	2,148
Total Load	**2,091**	**1,912**	**1,673**	**1,681**	**1,863**	**2,401**	**2,603**	**2,470**	**1,945**	**1,651**	**1,755**	**2,030**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,721	2,460	2,166	2,124	2,814	3,826	4,001	3,759	3,057	2,208	2,416	2,736
System Peak Load (1 hour) 95th Percentile	2,753	2,544	2,212	2,139	2,835	3,867	4,026	3,796	3,074	2,226	2,458	2,823

2028 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	937	771	627	542	479	588	740	687	516	517	670	866
Commercial	572	520	487	478	483	536	564	575	510	498	508	570
Irrigation	3	3	9	128	349	671	679	587	339	72	5	3
Industrial	297	292	303	292	295	318	312	320	311	314	306	303
Additional Firm	141	136	133	127	126	117	126	129	134	136	145	148
Loss	166	145	129	130	146	193	211	199	152	126	135	160
System Load	**2,116**	**1,866**	**1,688**	**1,696**	**1,879**	**2,424**	**2,631**	**2,497**	**1,962**	**1,664**	**1,769**	**2,051**
Light Load	1,976	1,719	1,549	1,537	1,708	2,192	2,375	2,211	1,770	1,491	1,629	1,900
Heavy Load	2,236	1,976	1,788	1,823	2,014	2,593	2,852	2,704	2,116	1,800	1,882	2,181
Total Load	**2,116**	**1,866**	**1,688**	**1,696**	**1,879**	**2,424**	**2,631**	**2,497**	**1,962**	**1,664**	**1,769**	**2,051**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,747	2,480	2,183	2,137	2,829	3,874	4,048	3,812	3,087	2,222	2,430	2,761
System Peak Load (1 hour) 95th Percentile	2,780	2,564	2,229	2,152	2,849	3,916	4,073	3,849	3,104	2,240	2,472	2,848

2029 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	952	810	635	548	484	597	752	698	522	522	676	875
Commercial	581	546	493	484	489	543	572	583	516	503	514	578
Irrigation	3	3	9	129	352	676	684	592	342	73	5	3
Industrial	298	304	304	293	297	319	313	322	313	316	307	304
Additional Firm	142	141	133	127	127	118	127	130	134	137	145	149
Loss	168	152	130	132	147	195	214	201	154	127	136	161
System Load	**2,143**	**1,956**	**1,704**	**1,712**	**1,896**	**2,448**	**2,662**	**2,525**	**1,980**	**1,677**	**1,784**	**2,071**
Light Load	2,001	1,802	1,564	1,552	1,723	2,214	2,402	2,236	1,786	1,503	1,643	1,918
Heavy Load	2,255	2,072	1,805	1,840	2,032	2,618	2,885	2,734	2,150	1,803	1,898	2,202
Total Load	**2,143**	**1,956**	**1,704**	**1,712**	**1,896**	**2,448**	**2,662**	**2,525**	**1,980**	**1,677**	**1,784**	**2,071**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,777	2,505	2,203	2,151	2,844	3,928	4,097	3,869	3,119	2,237	2,444	2,786
System Peak Load (1 hour) 95th Percentile	2,809	2,589	2,249	2,166	2,865	3,970	4,121	3,906	3,136	2,255	2,487	2,873

2030 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	963	820	640	552	488	602	762	706	526	524	680	884
Commercial	590	554	499	491	495	550	580	592	522	509	521	585
Irrigation	3	3	9	130	355	682	690	597	345	73	5	3
Industrial	299	305	305	294	298	320	314	323	314	317	308	305
Additional Firm	142	141	133	127	127	118	127	130	134	137	145	149
Loss	170	154	131	133	149	197	216	203	155	128	137	163
System Load	**2,167**	**1,976**	**1,718**	**1,726**	**1,911**	**2,469**	**2,689**	**2,551**	**1,995**	**1,688**	**1,797**	**2,089**
Light Load	2,023	1,820	1,576	1,564	1,737	2,234	2,427	2,258	1,800	1,513	1,654	1,935
Heavy Load	2,280	2,093	1,829	1,844	2,048	2,658	2,895	2,762	2,167	1,815	1,912	2,222
Total Load	**2,167**	**1,976**	**1,718**	**1,726**	**1,911**	**2,469**	**2,689**	**2,551**	**1,995**	**1,688**	**1,797**	**2,089**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,799	2,524	2,215	2,163	2,858	3,966	4,143	3,915	3,147	2,250	2,457	2,803
System Peak Load (1 hour) 95th Percentile	2,832	2,608	2,261	2,178	2,878	4,008	4,167	3,953	3,164	2,268	2,499	2,890

2031 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	975	829	645	555	491	608	772	715	530	526	684	892
Commercial	598	561	505	497	501	556	588	600	528	515	526	593
Irrigation	3	3	9	131	357	687	695	601	347	74	5	3
Industrial	300	306	307	295	299	322	315	324	315	318	310	306
Additional Firm	142	141	134	128	127	118	127	130	134	137	145	149
Loss	172	155	132	134	150	199	218	205	156	129	138	164
System Load	**2,191**	**1,996**	**1,731**	**1,739**	**1,925**	**2,490**	**2,716**	**2,576**	**2,011**	**1,699**	**1,809**	**2,108**
Light Load	2,046	1,838	1,589	1,576	1,750	2,253	2,451	2,281	1,814	1,523	1,666	1,952
Heavy Load	2,295	2,114	1,843	1,858	2,052	2,681	2,907	2,809	2,155	1,827	1,925	2,220
Total Load	**2,191**	**1,996**	**1,731**	**1,739**	**1,925**	**2,490**	**2,716**	**2,576**	**2,011**	**1,699**	**1,809**	**2,108**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,826	2,545	2,233	2,174	2,871	4,019	4,189	3,971	3,174	2,262	2,469	2,828
System Peak Load (1 hour) 95th Percentile	2,859	2,629	2,278	2,189	2,892	4,060	4,213	4,008	3,191	2,280	2,511	2,915

2032 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	987	810	650	559	495	614	782	724	534	529	688	899
Commercial	607	549	510	503	507	563	596	608	534	520	532	599
Irrigation	3	3	9	132	360	692	700	606	350	74	5	3
Industrial	301	297	308	296	300	323	316	325	316	319	311	307
Additional Firm	142	137	134	128	127	118	127	130	135	138	146	150
Loss	174	151	133	135	151	201	221	208	158	130	139	166
System Load	**2,214**	**1,946**	**1,744**	**1,752**	**1,940**	**2,511**	**2,742**	**2,601**	**2,026**	**1,710**	**1,821**	**2,124**
Light Load	2,068	1,792	1,601	1,588	1,763	2,271	2,475	2,303	1,827	1,532	1,677	1,967
Heavy Load	2,320	2,071	1,847	1,872	2,079	2,686	2,935	2,836	2,171	1,850	1,927	2,237
Total Load	**2,214**	**1,946**	**1,744**	**1,752**	**1,940**	**2,511**	**2,742**	**2,601**	**2,026**	**1,710**	**1,821**	**2,124**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,849	2,559	2,245	2,185	2,884	4,057	4,234	4,017	3,201	2,274	2,480	2,844
System Peak Load (1 hour) 95th Percentile	2,882	2,644	2,290	2,200	2,905	4,099	4,258	4,054	3,218	2,292	2,522	2,930

2033 Monthly Summary	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Average Load (aMW) 50th Percentile												
Residential	996	846	653	560	496	618	790	731	536	529	690	906
Commercial	615	575	515	509	512	569	603	616	539	525	538	606
Irrigation	3	3	9	133	363	697	706	610	353	75	5	3
Industrial	302	308	309	297	301	324	317	326	317	320	312	308
Additional Firm	143	142	134	128	128	119	128	131	135	138	146	150
Loss	176	158	134	136	152	202	223	209	159	130	140	167
System Load	**2,235**	**2,032**	**1,755**	**1,762**	**1,952**	**2,529**	**2,766**	**2,624**	**2,038**	**1,718**	**1,831**	**2,140**
Light Load	2,087	1,872	1,610	1,597	1,774	2,288	2,496	2,323	1,839	1,539	1,685	1,982
Heavy Load	2,352	2,153	1,859	1,883	2,092	2,706	2,979	2,841	2,184	1,859	1,937	2,254
Total Load	**2,235**	**2,032**	**1,755**	**1,762**	**1,952**	**2,529**	**2,766**	**2,624**	**2,038**	**1,718**	**1,831**	**2,140**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,870	2,579	2,255	2,195	2,895	4,096	4,277	4,062	3,224	2,283	2,489	2,860
System Peak Load (1 hour) 95th Percentile	2,902	2,664	2,301	2,210	2,916	4,137	4,301	4,099	3,241	2,301	2,532	2,947

2034 Monthly Summary	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Average Load (aMW) 50th Percentile												
Residential	1,008	856	659	564	501	625	801	741	541	533	695	916
Commercial	622	581	520	514	517	575	610	623	544	530	542	612
Irrigation	3	3	9	134	365	703	711	615	355	76	5	3
Industrial	303	309	310	298	302	325	318	327	318	321	313	309
Additional Firm	143	142	134	128	128	119	128	131	135	138	146	150
Loss	178	160	135	137	153	204	225	212	160	131	141	169
System Load	**2,257**	**2,051**	**1,767**	**1,775**	**1,966**	**2,551**	**2,794**	**2,650**	**2,054**	**1,729**	**1,844**	**2,159**
Light Load	2,108	1,889	1,622	1,609	1,787	2,307	2,522	2,346	1,853	1,549	1,697	1,999
Heavy Load	2,375	2,172	1,871	1,908	2,095	2,729	3,009	2,869	2,201	1,871	1,951	2,284
Total Load	**2,257**	**2,051**	**1,767**	**1,775**	**1,966**	**2,551**	**2,794**	**2,650**	**2,054**	**1,729**	**1,844**	**2,159**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,893	2,598	2,269	2,205	2,908	4,142	4,324	4,114	3,252	2,296	2,502	2,882
System Peak Load (1 hour) 95th Percentile	2,926	2,682	2,315	2,220	2,928	4,184	4,348	4,151	3,269	2,314	2,544	2,969

2035 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	1,022	868	667	571	507	635	816	754	548	538	702	927
Commercial	630	587	525	519	521	581	617	630	549	534	547	618
Irrigation	3	3	9	135	368	708	717	620	358	76	6	3
Industrial	304	310	310	299	303	326	319	328	319	322	313	309
Additional Firm	143	142	135	129	128	119	128	131	136	139	147	150
Loss	180	162	136	138	155	206	227	214	161	132	142	170
System Load	**2,282**	**2,072**	**1,781**	**1,790**	**1,982**	**2,575**	**2,824**	**2,678**	**2,070**	**1,741**	**1,857**	**2,178**
Light Load	2,131	1,908	1,635	1,622	1,802	2,329	2,549	2,371	1,868	1,560	1,709	2,017
Heavy Load	2,391	2,194	1,887	1,924	2,113	2,755	3,041	2,899	2,233	1,872	1,965	2,305
Total Load	**2,282**	**2,072**	**1,781**	**1,790**	**1,982**	**2,575**	**2,824**	**2,678**	**2,070**	**1,741**	**1,857**	**2,178**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,919	2,619	2,286	2,218	2,923	4,192	4,372	4,168	3,281	2,309	2,515	2,905
System Peak Load (1 hour) 95th Percentile	2,952	2,703	2,331	2,233	2,943	4,233	4,397	4,206	3,298	2,327	2,557	2,992

2036 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	1,038	851	675	579	514	646	832	768	555	543	709	938
Commercial	637	572	529	524	526	586	624	637	553	538	552	624
Irrigation	3	3	9	136	371	714	722	625	361	77	6	3
Industrial	304	300	311	299	303	326	320	329	319	322	314	310
Additional Firm	144	138	135	129	129	120	129	132	136	139	147	151
Loss	182	158	138	139	156	208	230	216	163	133	143	172
System Load	**2,308**	**2,021**	**1,797**	**1,806**	**2,000**	**2,600**	**2,856**	**2,706**	**2,088**	**1,753**	**1,870**	**2,198**
Light Load	2,155	1,862	1,649	1,637	1,817	2,352	2,577	2,396	1,883	1,570	1,722	2,036
Heavy Load	2,418	2,139	1,913	1,929	2,131	2,798	3,057	2,951	2,237	1,884	1,990	2,315
Total Load	**2,308**	**2,021**	**1,797**	**1,806**	**2,000**	**2,600**	**2,856**	**2,706**	**2,088**	**1,753**	**1,870**	**2,198**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,948	2,638	2,304	2,232	2,939	4,247	4,422	4,226	3,312	2,322	2,528	2,931
System Peak Load (1 hour) 95th Percentile	2,980	2,722	2,350	2,247	2,959	4,288	4,446	4,264	3,329	2,340	2,570	3,018

2037 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	1,053	894	684	586	522	657	847	781	563	548	716	949
Commercial	644	599	533	529	531	591	630	644	557	542	556	629
Irrigation	3	3	9	137	374	719	728	630	364	77	6	3
Industrial	305	311	311	300	304	327	320	329	320	323	314	310
Additional Firm	144	143	135	129	129	120	129	132	136	139	147	151
Loss	184	165	139	141	158	210	233	219	164	134	145	173
System Load	**2,333**	**2,115**	**1,811**	**1,821**	**2,016**	**2,624**	**2,887**	**2,735**	**2,104**	**1,764**	**1,883**	**2,216**
Light Load	2,179	1,948	1,662	1,650	1,833	2,374	2,605	2,421	1,898	1,581	1,734	2,052
Heavy Load	2,445	2,240	1,928	1,945	2,161	2,807	3,090	2,982	2,255	1,897	2,004	2,334
Total Load	**2,333**	**2,115**	**1,811**	**1,821**	**2,016**	**2,624**	**2,887**	**2,735**	**2,104**	**1,764**	**1,883**	**2,216**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,974	2,662	2,320	2,245	2,954	4,295	4,471	4,280	3,341	2,335	2,540	2,951
System Peak Load (1 hour) 95th Percentile	3,006	2,747	2,366	2,260	2,974	4,336	4,495	4,317	3,358	2,353	2,583	3,038

2038 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	1,068	906	691	593	528	667	862	794	569	553	722	959
Commercial	650	604	537	533	534	596	636	650	561	546	560	633
Irrigation	3	3	9	138	377	725	734	635	367	78	6	4
Industrial	305	311	312	300	304	327	321	330	320	323	315	311
Additional Firm	144	143	135	129	129	120	129	132	137	140	148	151
Loss	186	167	140	142	159	212	235	221	165	135	146	175
System Load	**2,357**	**2,134**	**1,825**	**1,835**	**2,032**	**2,647**	**2,917**	**2,762**	**2,119**	**1,774**	**1,895**	**2,233**
Light Load	2,201	1,966	1,675	1,663	1,847	2,395	2,632	2,445	1,912	1,590	1,744	2,069
Heavy Load	2,480	2,261	1,933	1,960	2,178	2,832	3,122	3,011	2,271	1,920	2,005	2,352
Total Load	**2,357**	**2,134**	**1,825**	**1,835**	**2,032**	**2,647**	**2,917**	**2,762**	**2,119**	**1,774**	**1,895**	**2,233**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,998	2,682	2,334	2,257	2,968	4,341	4,519	4,332	3,369	2,347	2,552	2,971
System Peak Load (1 hour) 95th Percentile	3,031	2,766	2,380	2,272	2,988	4,382	4,544	4,369	3,386	2,364	2,594	3,058

Annual Summary

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Billed Sales (MWh) 70th Percentile										
Residential	5,437,937	5,493,644	5,547,973	5,608,333	5,688,441	5,763,194	5,834,023	5,890,805	5,944,148	6,014,532
Commercial	4,196,788	4,251,251	4,291,921	4,350,949	4,401,332	4,448,900	4,505,483	4,562,301	4,615,732	4,674,083
Irrigation	2,074,146	2,093,175	2,106,818	2,123,833	2,140,578	2,156,322	2,171,522	2,187,603	2,204,350	2,221,073
Industrial	2,481,792	2,510,977	2,547,534	2,570,263	2,595,285	2,619,587	2,638,463	2,652,628	2,669,207	2,681,291
Additional Firm	956,699	977,000	1,013,000	1,048,000	1,069,000	1,146,000	1,161,000	1,164,000	1,167,000	1,171,000
System Load	15,147,362	15,326,046	15,507,246	15,701,378	15,894,635	16,134,002	16,310,491	16,457,337	16,600,437	16,761,979
Total Load	**15,147,362**	**15,326,046**	**15,507,246**	**15,701,378**	**15,894,635**	**16,134,002**	**16,310,491**	**16,457,337**	**16,600,437**	**16,761,979**
Generation Month Sales (MWh) 70th Percentile										
Residential	5,442,618	5,498,804	5,552,533	5,614,209	5,693,977	5,768,505	5,838,363	5,894,961	5,949,634	6,020,876
Commercial	4,200,298	4,253,908	4,295,719	4,354,214	4,404,424	4,452,555	4,509,159	4,565,769	4,619,509	4,678,039
Irrigation	2,074,158	2,093,183	2,106,828	2,123,843	2,140,588	2,156,331	2,171,532	2,187,613	2,204,360	2,221,083
Industrial	2,484,235	2,514,036	2,549,437	2,572,357	2,597,319	2,621,167	2,639,649	2,654,015	2,670,219	2,682,204
Additional Firm	956,699	977,000	1,013,000	1,048,000	1,069,000	1,146,000	1,161,000	1,164,000	1,167,000	1,171,000
System Sales	**15,158,009**	**15,336,932**	**15,517,517**	**15,712,623**	**15,905,307**	**16,144,558**	**16,319,702**	**16,466,359**	**16,610,723**	**16,773,202**
Total Sales	**15,158,009**	**15,336,932**	**15,517,517**	**15,712,623**	**15,905,307**	**16,144,558**	**16,319,702**	**16,466,359**	**16,610,723**	**16,773,202**
Loss	1,290,909	1,305,542	1,319,389	1,335,058	1,351,249	1,368,458	1,383,403	1,396,552	1,409,433	1,424,125
Required Generation	**16,448,918**	**16,642,475**	**16,836,907**	**17,047,681**	**17,256,557**	**17,513,016**	**17,703,106**	**17,862,910**	**18,020,155**	**18,197,327**
Average Load (aMW) 70th Percentile										
Residential	621	626	634	641	650	657	666	673	679	685
Commercial	479	484	490	497	503	507	515	521	527	533
Irrigation	237	238	241	242	244	245	248	250	252	253
Industrial	284	286	291	294	296	298	301	303	305	305
Additional Firm	109	111	116	120	122	130	133	133	133	133
Loss	147	149	151	152	154	156	158	159	161	162
System Load	**1,878**	**1,895**	**1,922**	**1,946**	**1,970**	**1,994**	**2,021**	**2,039**	**2,057**	**2,072**
Light Load	1,708	1,723	1,748	1,770	1,792	1,814	1,838	1,855	1,871	1,885
Heavy Load	2,010	2,029	2,058	2,084	2,110	2,134	2,164	2,183	2,203	2,219
Total Load	**1,878**	**1,895**	**1,922**	**1,946**	**1,970**	**1,994**	**2,021**	**2,039**	**2,057**	**2,072**
Peak Load (MW) 95th Percentile										
System Peak (1 hour)	3,634	3,683	3,731	3,782	3,832	3,887	3,935	3,980	4,026	4,073
Total Peak Load	**3,634**	**3,683**	**3,731**	**3,782**	**3,832**	**3,887**	**3,935**	**3,980**	**4,026**	**4,073**

	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Billed Sales (MWh) 70th Percentile										
Residential	6,095,509	6,152,545	6,212,850	6,269,841	6,312,160	6,378,952	6,464,432	6,557,678	6,648,731	6,734,413
Commercial	4,735,240	4,799,479	4,857,014	4,919,215	4,972,567	5,023,928	5,074,557	5,123,093	5,170,831	5,211,986
Irrigation	2,237,536	2,254,044	2,270,422	2,286,620	2,303,006	2,319,804	2,336,631	2,353,973	2,371,564	2,389,219
Industrial	2,692,197	2,700,947	2,713,441	2,720,965	2,731,480	2,739,017	2,745,330	2,750,321	2,754,092	2,758,211
Additional Firm	1,173,000	1,176,000	1,178,000	1,180,000	1,183,000	1,186,000	1,188,000	1,191,000	1,193,000	1,196,000
System Load	**16,933,481**	**17,083,016**	**17,231,727**	**17,376,641**	**17,502,212**	**17,647,701**	**17,808,951**	**17,976,065**	**18,138,217**	**18,289,829**
Total Load	**16,933,481**	**17,083,016**	**17,231,727**	**17,376,641**	**17,502,212**	**17,647,701**	**17,808,951**	**17,976,065**	**18,138,217**	**18,289,829**
Generation Month Sales (MWh) 70th Percentile										
Residential	6,100,167	6,157,528	6,217,678	6,273,685	6,316,791	6,384,855	6,470,892	6,563,965	6,654,615	6,740,060
Commercial	4,739,391	4,803,216	4,861,046	4,922,698	4,975,928	5,027,246	5,077,747	5,126,236	5,173,564	5,214,450
Irrigation	2,237,546	2,254,054	2,270,432	2,286,630	2,303,016	2,319,814	2,336,642	2,353,984	2,371,575	2,389,230
Industrial	2,692,929	2,701,993	2,714,070	2,721,845	2,732,111	2,739,546	2,745,748	2,750,637	2,754,437	2,758,943
Additional Firm	1,173,000	1,176,000	1,178,000	1,180,000	1,183,000	1,186,000	1,188,000	1,191,000	1,193,000	1,196,000
System Sales	**16,943,033**	**17,092,792**	**17,241,226**	**17,384,857**	**17,510,845**	**17,657,460**	**17,819,029**	**17,985,821**	**18,147,190**	**18,298,683**
Total Sales	**16,943,033**	**17,092,792**	**17,241,226**	**17,384,857**	**17,510,845**	**17,657,460**	**17,819,029**	**17,985,821**	**18,147,190**	**18,298,683**
Loss	1,439,675	1,453,295	1,466,761	1,479,909	1,491,254	1,504,694	1,519,675	1,535,160	1,550,227	1,564,294
Required Generation	**18,382,709**	**18,546,087**	**18,707,987**	**18,864,766**	**19,002,100**	**19,162,154**	**19,338,704**	**19,520,980**	**19,697,417**	**19,862,977**
Average Load (aMW) 70th Percentile										
Residential	696	703	710	714	721	729	739	747	760	769
Commercial	541	548	555	560	568	574	580	584	591	595
Irrigation	255	257	259	260	263	265	267	268	271	273
Industrial	307	308	310	310	312	313	313	313	314	315
Additional Firm	134	134	134	134	135	135	136	136	136	137
Loss	164	166	167	168	170	172	173	175	177	179
System Load	**2,098**	**2,117**	**2,136**	**2,148**	**2,169**	**2,187**	**2,208**	**2,222**	**2,249**	**2,267**
Light Load	1,909	1,926	1,943	1,954	1,973	1,990	2,008	2,022	2,046	2,063
Heavy Load	2,247	2,267	2,281	2,293	2,316	2,336	2,357	2,373	2,401	2,421
Total Load	**2,098**	**2,117**	**2,136**	**2,148**	**2,169**	**2,187**	**2,208**	**2,222**	**2,249**	**2,267**
Peak Load (MW) 95th Percentile										
System Peak (1 hour)	4,121	4,167	4,213	4,258	4,301	4,348	4,397	4,446	4,495	4,544
Total Peak Load	4,121	4,167	4,213	4,258	4,301	4,348	4,397	4,446	4,495	4,544

Demand-Side Resource Data

DSM Financial Assumptions

Avoided Levelized Capacity Costs	
Reciprocating Internal Combustion Engine (RICE)	$121.19/kW-year
Financial Assumptions	
Discount rate (weighted average cost of capital)	7.12%
Financial escalation factor	2.20%
Transmission Losses	
Non-summer secondary losses	9.60%
Summer peak loss	9.70%

Avoided Cost Averages ($/MWh except where noted)

Year	Summer On-Peak[1]	Summer Mid-Peak	Summer Off-Peak	Non-Summer Mid-Peak	Non-Summer Off-Peak	Annual Average[2]	Annual T&D On-Peak Deferral Value ($/kW-year)
2019	$44.25	$30.93	$27.15	$27.62	$23.11	$42.64	$6.52
2020	$47.17	$30.09	$26.65	$27.89	$23.04	$42.48	$4.10
2021	$50.02	$32.14	$28.38	$28.85	$24.22	$43.84	$4.10
2022	$52.88	$32.97	$28.97	$29.62	$25.35	$44.84	$4.10
2023	$54.91	$34.45	$29.94	$30.49	$26.42	$45.90	$3.99
2024	$56.78	$36.59	$32.11	$32.88	$27.97	$47.87	$3.99
2025	$58.50	$38.44	$33.77	$34.49	$29.61	$49.57	$3.84
2026	$60.06	$36.45	$29.23	$35.82	$28.36	$49.27	$3.94
2027	$61.46	$38.80	$32.47	$38.86	$31.27	$52.10	$4.10
2028	$62.79	$42.29	$35.52	$40.54	$33.90	$54.32	$4.22
2029	$64.09	$43.66	$39.51	$42.43	$36.96	$56.75	$4.28
2030	$65.39	$44.72	$38.76	$42.36	$36.83	$56.79	$4.22
2031	$66.67	$47.61	$42.11	$45.57	$39.65	$59.75	$4.28
2032	$67.95	$48.68	$43.86	$47.19	$41.24	$61.26	$4.28
2033	$69.24	$49.94	$44.90	$48.55	$42.85	$62.70	$4.28
2034	$70.55	$51.39	$46.69	$50.04	$44.42	$64.01	$2.49
2035	$71.90	$52.98	$47.92	$52.00	$45.97	$65.72	$2.67
2036	$73.27	$55.74	$49.99	$54.04	$47.63	$67.63	$2.59
2037	$74.88	$56.50	$52.01	$56.40	$49.00	$69.35	$1.40
2038	$76.53	$55.18	$52.09	$55.50	$49.35	$69.04	$1.49

[1] Estimated average annual variable operations and management costs of a 111 MW-capacity RICE unit.

[2] Annual average across all hours includes avoided capacity value of $121.19 kW-year from a 111 MW RICE unit applied across Summer On-Peak hours.

Bundle Amounts

Cumulative Achievable Potential (aMW)

Bundle	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
0-10th Percentile	1	3	4	6	7	9	11	13	15	17
10-20th Percentile	3	3	5	6	8	10	11	13	15	17
20-30th Percentile	3	5	7	9	12	14	16	18	20	22
30-40th Percentile	1	3	5	6	8	10	12	14	16	18
40-50th Percentile	2	3	5	6	8	10	11	13	14	16
50-60th Percentile	1	3	4	6	7	8	10	11	13	14
60-70th Percentile	2	4	6	9	11	13	15	17	19	21
70-80th Percentile	3	6	10	13	16	19	21	23	25	27
80-90th Percentile	2	5	7	10	13	16	19	21	24	26
90-100th Percentile	2	4	6	8	11	14	16	19	22	24
High Cost	2	5	8	11	14	17	20	23	25	27
Total	**24**	**44**	**67**	**90**	**115**	**140**	**163**	**186**	**208**	**228**

Bundle	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
0-10th Percentile	19	21	23	25	27	29	30	31	32	33
10-20th Percentile	19	20	22	25	27	28	30	31	32	33
20-30th Percentile	23	25	26	28	29	31	32	32	33	34
30-40th Percentile	20	22	24	25	27	28	30	31	32	33
40-50th Percentile	17	19	21	23	25	27	28	30	32	34
50-60th Percentile	15	17	19	20	22	24	26	29	31	33
60-70th Percentile	22	24	25	26	28	29	30	31	32	33
70-80th Percentile	28	29	30	31	32	32	33	33	33	34
80-90th Percentile	28	29	30	31	31	32	32	33	33	34
90-100th Percentile	26	28	29	30	30	31	32	32	33	33
High Cost	29	31	33	34	35	37	38	39	40	41
Total	**247**	**265**	**282**	**298**	**314**	**327**	**340**	**352**	**364**	**375**

Bundle Costs

Savings-Weighted Levelized Cost of Energy ($/MWh) Real Dollars

Bundle	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
0-10th Percentile	-$115	-$111	-$106	-$102	-$99	-$97	-$108	-$108	-$105	-$104
10-20th Percentile	-$5	-$8	-$7	-$5	-$5	-$5	-$15	-$15	-$15	-$15
20-30th Percentile	$14	$14	$14	$14	$14	$15	$14	$14	$15	$15
30-40th Percentile	$38	$38	$38	$38	$38	$38	$32	$32	$32	$32
40-50th Percentile	$42	$42	$42	$42	$41	$42	$40	$40	$39	$39
50-60th Percentile	$56	$56	$55	$55	$55	$55	$56	$55	$55	$54
60-70th Percentile	$68	$69	$69	$69	$69	$69	$69	$69	$69	$69
70-80th Percentile	$138	$138	$139	$139	$139	$139	$136	$133	$130	$127
80-90th Percentile	$133	$135	$136	$137	$138	$137	$135	$134	$133	$132
90-100th Percentile	$192	$190	$189	$188	$188	$188	$187	$187	$187	$188
High Cost	$2,145	$2,144	$2,121	$2,094	$2,063	$2,001	$1,936	$1,876	$1,866	$1,906
Total	**$277**	**$312**	**$322**	**$330**	**$331**	**$325**	**$299**	**$285**	**$278**	**$271**

Bundle	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	20-Year Average
0-10th Percentile	-$103	-$105	-$104	-$103	-$103	-$91	-$92	-$89	-$83	-$90	-$102
10-20th Percentile	-$15	-$27	-$27	-$27	-$27	-$28	-$29	-$29	-$30	-$30	-$18
20-30th Percentile	$15	$15	$15	$15	$15	$15	$15	$13	$13	$12	$14
30-40th Percentile	$32	$27	$27	$27	$26	$26	$26	$27	$27	$27	$32
40-50th Percentile	$38	$35	$35	$34	$34	$34	$34	$34	$34	$34	$38
50-60th Percentile	$52	$45	$44	$43	$42	$42	$42	$40	$40	$40	$48
60-70th Percentile	$70	$69	$69	$69	$69	$69	$69	$69	$69	$69	$69
70-80th Percentile	$123	$120	$116	$112	$109	$107	$76	$73	$71	$69	$131
80-90th Percentile	$131	$130	$128	$126	$124	$121	$110	$111	$111	$112	$133
90-100th Percentile	$189	$190	$192	$194	$195	$196	$195	$195	$195	$195	$189
High Cost	$2,025	$2,204	$2,424	$2,653	$2,858	$3,049	$3,260	$3,261	$3,366	$3,463	$2,235
Total	**$267**	**$257**	**$257**	**$257**	**$259**	**$292**	**$296**	**$329**	**$359**	**$384**	$290

SUPPLY-SIDE RESOURCE DATA

Key Financial and Forecast Assumptions

Financing Cap Structure and Cost	
Composition	
Debt	50.10%
Preferred	0.00%
Common	49.90%
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])	7.12%
Composite tax rate	25.74%
Deferred rate	21.30%
General O&M escalation rate	2.20%
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)	7.65%

[1] Incorporates tax effects.

Fuel Forecast Base Case (Nominal, $ per MMBTU)

Year	Generic Coal	Nuclear
2019	$2.40	
2020	$2.49	
2021	$2.55	
2022	$2.62	
2023	$2.68	$0.62
2024	$2.74	$0.63
2025	$2.80	$0.65
2026	$2.86	$0.66
2027	$2.91	$0.68
2028	$2.96	$0.69
2029	$3.01	$0.71
2030	$3.08	$0.72
2031	$3.15	$0.74
2032	$3.21	$0.75
2033	$3.30	$0.77
2034	$3.39	$0.79
2035	$3.46	$0.81
2036	$3.57	$0.82
2037	$3.65	$0.84
2038	$3.75	$0.86

Cost Inputs and Operating Assumptions (Costs in 2019$)

Supply-Side Resources	Plant Capacity (MW)	Plant Capital ($/kW)[1,3]	Transmission Capital ($/kW)	Total Capital ($/kW)	Total Investment ($/kW)[2]	Fixed O&M ($/kW-mth)[3]	Variable O&M ($/MWh)	Integration ($/MWh)	Heat Rate (Btu/kWh)	Economic Life (years)
Biomass (35 MW)	35	$3,577	$133	$3,710	$4,614	$3.13	$16.68	$0.00	0	30
Boardman to Hemingway (350 MW)	350	$0	$894	$894	$894	$0.42	$0.00	$0.00	0	55
CCCT (1x1) F Class (300 MW)	300	$1,096	$102	$1,198	$1,401	$0.92	$2.90	$0.00	6,420	30
Geothermal (30 MW)	30	$6,014	$150	$6,164	$7,904	$15.05	$0.00	$0.00	0	25
Reciprocating Gas Engine (111.1 MW)	111	$885	$117	$1,002	$1,067	$1.00	$5.42	$0.00	8,300	40
Reciprocating Gas Engine (55.5 MW)	56	$994	$117	$1,111	$1,183	$1.00	$5.42	$0.00	8,300	40
SCCT—Frame F Class (170 MW)	170	$932	$122	$1,054	$1,122	$1.07	$7.48	$0.00	9,720	35
Small Modular Nuclear (60 MW)	60	$4,292	$165	$4,457	$6,722	$0.70	$2.09	$0.00	11,493	40
Solar PV—Residential Rooftop (.005 MW)	0.005	$3,590	$0	$3,590	$3,730	$1.79	$0.00	$0.00	0	25
Solar PV—Utility Scale 1-Axis Tracking (40 MW)	40	$1,402	$150	$1,552	$1,613	$1.02	$0.00	$0.63	0	30
Solar PV—Utility Scale 1-Axis Tracking (40 MW) w/ 4-hr Battery (10 MW)	50	$1,658	$150	$1,808	$1,879	$0.97	$0.49	$0.63	0	30
Solar PV—Utility Scale 1-Axis Tracking (40 MW) w/ 4-hr Battery (20 MW)	60	$1,829	$150	$1,979	$2,056	$0.94	$0.81	$0.63	0	30
Solar PV—Utility Scale 1-Axis Tracking (40 MW) w/ 4-hr Battery (30 MW)	70	$1,950	$150	$2,100	$2,183	$0.92	$1.03	$0.63	0	30
Solar PV—Targeted Siting for Grid Benefit (0.5 MW)	0.5	$1,823	-$62	$1,761	$1,830	$0.93	$0.00	$0.00	0	25
Storage—Li Battery 4 hour (5 MW)	5	$1,973	$52	$2,025	$2,064	$0.78	$2.47	$0.00	0	20
Storage—Li Battery 8 hour (5 MW)	5	$3,277	$52	$3,329	$3,393	$0.78	$2.47	$0.00	0	10
Storage—Pumped-Hydro (500 MW)	500	$1,800	$191	$1,991	$2,315	$0.33	$0.00	$0.00	0	75
Wind ID (100 MW)	100	$1,623	$122	$1,745	$1,863	$4.47	$0.00	$20.29	0	25
Wind WY (100 MW)	100	$1,623	$122	$1,745	$1,863	$4.47	$0.00	$20.29	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)

Levelized Cost of Energy (Costs in 2023$, $/MWh)[1]

At stated capacity factors

Supply-Side Resources	Cost of Capital	Non-Fuel O&M[2]	Fuel	Wholesale Energy	Net of Tax Credit/ Integration	Total Cost per MWh	Capacity Factor
Biomass (35 MW)[3]	$65	$36	$0	$0	$0	$101	85%
Boardman to Hemingway (350 MW)	$26	$3	$0	$40	-$8	$62	33%
CCCT (1x1) F Class (300 MW)	$28	$9	$34	$0	$0	$71	60%
Geothermal (30 MW)	$103	$41	$0	$0	$0	$144	88%
Reciprocating Gas Engine (111.1 MW)	$79	$29	$46	$0	$0	$155	15%
Reciprocating Gas Engine (55.5 MW)	$88	$30	$46	$0	$0	$164	15%
SCCT—Frame F Class (170 MW)	$256	$76	$53	$0	$0	$386	5%
Small Modular Nuclear (60 MW)	$83	$28	$10	$0	$0	$121	90%
Solar PV—Residential Rooftop (.005 MW)	$154	$25	$0	$0	$0	$180	21%
Solar PV—Utility Scale 1-Axis Tracking (40 MW)	$60	$12	$0	$0	-$5	$67	26%
Solar PV—Utility Scale 1-Axis Tracking (40 MW) w/ 4-Hr Battery (10 MW)	$82	$16	$0	$0	-$7	$90	22%
Solar PV—Utility Scale 1-Axis Tracking (40 MW) w/ 4-Hr Battery (20 MW)	$109	$20	$0	$0	-$10	$120	18%
Solar PV—Utility Scale 1-Axis Tracking (40 MW) w/ 4-Hr Battery (30 MW)	$139	$25	$0	$0	-$13	$152	15%
Solar PV—Targeted Siting for Grid Benefit (0.5 MW)	$71	$12	$0	$0	-$6	$77	26%
Storage—Li Battery 4 hour (5 MW)[3]	$201	$30	$0	$0	$0	$232	11%
Storage—Li Battery 8 hour (5 MW)[3]	$231	$19	$0	$0	$0	$250	23%
Storage—Pumped-Hydro (500 MW)[3]	$153	$21	$0	$0	$0	$175	16%
Wind ID (100 MW)	$60	$28	$0	$0	$26	$114	35%
Wind WY (100 MW)	$47	$22	$0	$0	$26	$94	45%

[1] Levelized costing in 2023$ assuming 2023 online date. Common online date five years into IRP planning window allows levelized costing to capture projected trends in resource costs.
[2] Non-Fuel O&M includes fixed and variable costs, property taxes.
[3] Fuel costs not included for biomass resource. Storage resources do not include costs of recharge energy. As noted in IRP, levelized costing for storage resources driven overwhelmingly by fixed costs.

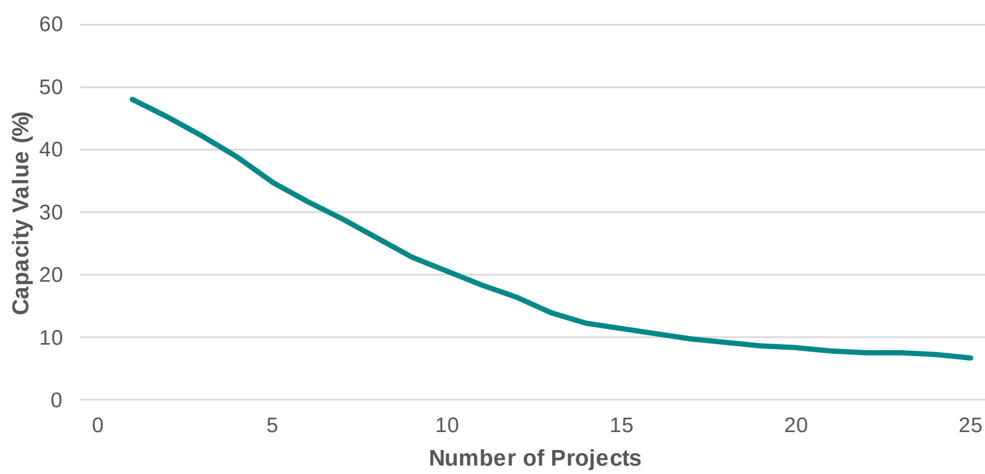
Levelized Capacity (fixed) Cost per kW/Month (Costs in 2019$)

Supply-Side Resources	Cost of Capital	Non-Fuel O&M	Tax Credit	Total Cost per kW
Biomass (35 MW)	$37	$7	$0	$44
Boardman to Hemingway (350 MW)	$6	$1	-$2	$5
CCCT (1x1) F Class (300 MW)	$11	$2	$0	$13
Geothermal (30 MW)	$61	$24	$0	$85
Reciprocating Gas Engine (111.1 MW)	$8	$2	$0	$10
Reciprocating Gas Engine (55.5 MW)	$9	$2	$0	$11
SCCT—Frame F Class (170 MW)	$9	$2	$0	$11
Small Modular Nuclear (60 MW)	$50	$6	$0	$56
Solar PV—Residential Rooftop (.005 MW)	$29	$3	$0	$31
Solar PV—Utility Scale 1-Axis Tracking (40 MW)	$12	$2	-$1	$13
Solar PV—Utility Scale 1-Axis Tracking (40 MW) w/ 4-Hr Battery (10 MW)	$14	$3	-$1	$15
Solar PV—Utility Scale 1-Axis Tracking (40 MW) w/ 4-Hr Battery (20 MW)	$15	$3	-$1	$16
Solar PV—Utility Scale 1-Axis Tracking (40 MW) w/ 4-Hr Battery (30 MW)	$16	$3	-$1	$17
Solar PV—Targeted Siting for Grid Benefit (0.5 MW)	$14	$2	-$1	$15
Storage—Li Battery 4 hour (5 MW)	$17	$2	$0	$20
Storage—Li Battery 8 hour (5 MW)	$43	$3	$0	$46
Storage—Pumped-Hydro (500 MW)	$16	$2	$0	$19
Wind ID (100 MW)	$14	$7	$0	$21
Wind WY (100 MW)	$15	$7	$0	$22

Solar Peak-Hour Capacity Credit (contribution to peak)

	Project MWAC	Total Installed MWAC ABV Current	Project Capacity Value (% Proj MWAC)	Project Capacity Value (MWAC)
Project 1	40	40	45.4%	18.1
Project 2	40	80	42.1%	16.9
Project 3	40	120	38.8%	15.5
Project 4	40	160	34.7%	13.9
Project 5	40	200	31.6%	12.7
Project 6	40	240	28.8%	11.5
Project 7	40	280	25.9%	10.4
Project 8	40	320	22.8%	9.1
Project 9	40	360	20.5%	8.2
Project 10	40	400	18.3%	7.3
Project 11	40	440	16.4%	6.5
Project 12	40	480	14.0%	5.6
Project 13	40	520	12.4%	5.0
Project 14	40	560	11.6%	4.6
Project 15	40	600	10.6%	4.2
Project 16	40	640	9.9%	4.0
Project 17	40	680	9.4%	3.7
Project 18	40	720	8.7%	3.5
Project 19	40	760	8.5%	3.4
Project 20	40	800	8.0%	3.2
Project 21	40	840	7.7%	3.1
Project 22	40	880	7.7%	3.1
Project 23	40	920	7.2%	2.9
Project 24	40	960	6.9%	2.8

Capacity value of incremental solar PV projects (40 MW each)



PURPA Reference Data

The following information is provided for PURPA reference purposes.

1. Preferred portfolio: Portfolio P16(4)

Resource Portfolio

Date	Resource	Installed Capacity (MW)	Peak-Hour Capacity (MW)
2019	Valmy Unit 1	(127)	(127)[1]
2020	Boardman	(58)	(58)[2]
2022	Bridger Unit	(177)	(177)
2023	Solar	120	51
2025	Valmy Unit 2	(133)	(133)[1]
2026	B2H	500 (Apr–Sep)/ 200 (Oct–Mar)	500
2026	Bridger Unit	(180)	(180)
2028	Bridger Unit	(174)	(174)
2029	Solar	40	18
2029	Battery Storage	30	30
2030	CCCT	300	300
2030	Bridger Unit	(177)	(177)
2031	Demand Response	5	5
2032	Demand Response	5	5
2032	Solar	80	32
2032	Battery Storage	10	10
2033	Demand Response	5	5
2033	Solar	80	27
2033	Battery Storage	20	20
2034	Demand Response	5	5
2034	Solar	80	22
2034	Battery Storage	20	20
2035	Reciprocating Engine	111	111
2035	Demand Response	5	5
2036	Demand Response	5	5
2037	Solar	320	51
2038	Solar	440	36
2038	Wind	300	15

1. Exit from North Valmy units not considered to affect capacity deficiency period because of IRP's assumed peak-hour wholesale electric market imports across existing north Valmy transmission line.
2. Ceased coal-fired operations at Boardman in 2020 considered a committed resource action.

2. Deficiency period start

   First capacity deficit = (42) MW July 2029

3. Intermittent generation integration costs

   Idaho—Schedule 87[2]

   Oregon—Schedule 85[3]

Renewable Energy Certificate Forecast

Year	Nominal ($/MWh)
2019	4.84
2020	5.04
2021	5.31
2022	5.33
2023	5.44
2024	5.73
2025	5.75
2026	5.85
2027	5.89
2028	6.16
2029	6.21
2030	6.48
2031	6.53
2032	6.94
2033	7.07
2034	7.17
2035	7.55
2036	7.66
2037	8.04
2038	8.04

[2] idahopower.com/about-us/company-information/rates-and-regulatory/retail-tariffs-idaho/

[3] idahopower.com/about-us/company-information/rates-and-regulatory/oregon-special-agreements/

EXISTING RESOURCE DATA

Qualifying Facility Data (PURPA)

Cogeneration and Small Power Production Projects Status as of December 31, 2019.

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	Littlewood/Arkoosh	0.87	Aug-1986	Aug-2021
Baker City Hydro	0.24	Sep-2015	Sep-2030	Low Line Canal	7.97	May-1985	May-2020
Barber Dam	3.70	Apr-1989	Apr-2024	Low Line Midway Hydro	2.50	Aug-2007	Aug-2027
Birch Creek	0.05	Nov-1984	Nov-2039	Lowline #2	2.79	Apr-1988	Apr-2023
Black Canyon #3	0.13	Apr-2019	Apr-2039	Magic Reservoir	9.07	Jun-1989	Jun-2024
Black Canyon Bliss Hydro	0.03	Nov-2014	Oct-2035	Malad River	1.17	May-2019	May-2039
Blind Canyon	1.63	Dec-2014	Dec-2034	Marco Ranches	1.20	Aug-1985	Aug-2020
Box Canyon	0.30	Feb-2019	Feb-2039	MC6 Hydro	2.10	Jul-2019	Jul-2039
Briggs Creek	0.60	Oct-1985	Oct-2020	Mile 28	1.50	Jun-1994	Jun-2029
Bypass	9.96	Jun-1988	Jun-2023	Mitchell Butte	2.09	May-1989	Dec-2033
Canyon Springs	0.11	Jan-2019	Jan-2039	Mora Drop Small Hydro	1.85	Sep-2006	Sep-2026
Cedar Draw	1.55	Jun-1984	Jun-2039	Mud Creek/S&S	0.52	Feb-2017	Feb-2037
Clear Springs Trout	0.56	Nov-2018	Nov-2038	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	0.25	Jun-2018	Jun-2033	Owyhee Dam CSPP	5.00	Aug-1985	May-2033
Dietrich Drop	4.50	Aug-1988	Aug-2023	Pigeon Cove	1.89	Oct-1984	Nov-2039
Eightmile Hydro Project	0.36	Oct-2014	Oct-2034	Pristine Springs #1	0.10	May-2015	May-2020
Elk Creek	2.00	May-1986	May-2021	Pristine Springs #3	0.20	May-2015	May-2020
Fall 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	2.17	Jan-2018	Jan-2038
Faulkner Ranch	0.87	Aug-1987	Aug-2022	Rock Creek #2	1.90	Apr-1989	Apr-2024
Fisheries Dev.	0.26	Jul-1990	As Delivered	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-2017	Aug-2022
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	0.36	Feb-2017	Feb-2037
Horseshoe Bend Hydro	9.50	Sep-1995	Sep-2030	Snake River Pottery	0.07	Nov-1984	Dec-2027
Jim Knight	0.34	Jun-1985	Jun-2020	Snedigar	0.54	Jan-1985	Jan-2040
Koyle Small Hydro	1.25	Apr-2019	Apr-2039	Tiber Dam	7.50	Jun-2004	Jun-2024
Lateral # 10	2.06	May-1985	May-2020	Trout-Co	0.24	Dec-1986	Dec-2021
Lemoyne	0.08	Jun-1985	Jun-2020	Tunnel #1	7.00	Jun-1993	Feb-2035
Little Wood River Ranch II	1.25	Jun-2015	Oct-2035	White Water Ranch	0.16	Aug-1985	Aug-2020
Little Wood River Res	2.85	Feb-1985	Feb-2020	Wilson Lake Hydro	8.40	May-1993	May-2028

Total Hydro Nameplate Rating 148.85 MW

Thermal Projects			
Simplot Pocatello Cogen	15.90	Mar-2019	Mar-2022
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	End Date	Project	MW	Contract On-line Date	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	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	6.25	Jun-2018	Jun-2038
Fighting Creek Landfill	3.06	Apr-2014	Apr-2029				
Total Biomass Nameplate Rating 35.70 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	20.00	Mar-2017	Mar-2037	Ontario Solar Center	3.00	Dec-2019	Estimated
Baker Solar Center	15.00	Dec-2019	Estimated	Open Range Solar Center, LLC	10.00	Mar-2017	Mar-2037
Brush Solar	2.75	Oct-2019	Estimated	Orchard Ranch Solar, LLC	20.00	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	Simcoe 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 316.25 MW							

Wind Projects			
Bennett Creek Wind Farm	21.00	Dec-2008	Dec-2028
Benson Creek Windfarm	10.00	Mar-2017	Mar-2037
Burley Butte Wind Park	21.30	Feb-2011	Feb-2031
Camp Reed Wind Park	22.50	Dec-2010	Dec-2030
Cassia Wind Farm LLC	10.50	Mar-2009	Mar-2029
Cold Springs Windfarm	23.00	Dec-2012	Dec-2032
Desert Meadow Windfarm	23.00	Dec-2012	Dec-2032
Durbin Creek Windfarm	10.00	Mar-2017	Mar-2037
Fossil Gulch Wind	10.50	Sep-2005	Sep-2025
Golden Valley Wind Park	12.00	Feb-2011	Feb-2031
Hammett Hill Windfarm	23.00	Dec-2012	Dec-2032
High Mesa Wind Project	40.00	Dec-2012	Dec-2032
Horseshoe Bend Wind	9.00	Feb-2006	Feb-2026
Hot Springs Wind Farm	21.00	Dec-2008	Dec-2028
Jett Creek Windfarm	10.00	Mar-2017	Mar-2037
Lime Wind Energy	3.00	Dec-2011	Dec-2031
Mainline Windfarm	23.00	Dec-2012	Dec-2032
Milner Dam Wind	19.92	Feb-2011	Feb-2031
Oregon Trail Wind Park	13.50	Jan-2011	Jan-2031
Payne's Ferry Wind Park	21.00	Dec-2010	Dec-2030
Pilgrim Stage Station Wind Park	10.50	Jan-2011	Jan-2031
Prospector Windfarm	10.00	Mar-2017	Mar-2037
Rockland Wind Farm	80.00	Dec-2011	Dec-2036
Ryegrass Windfarm	23.00	Dec-2012	Dec-2032
Salmon Falls Wind	22.00	Apr-2011	Apr-2031
Sawtooth Wind Project	22.00	Nov-2011	Nov-2031
Thousand Springs Wind Park	12.00	Jan-2011	Jan-2031
Tuana Gulch Wind Park	10.50	Jan-2011	Jan-2031
Tuana Springs Expansion	35.70	May-2010	May-2030
Two Ponds Windfarm	23.00	Dec-2012	Dec-2032
Willow Spring Windfarm	10.00	Mar-2017	Mar-2037
Yahoo Creek Wind Park	21.00	Dec-2010	Dec-2030
Total Wind Nameplate Rating 626.92 MW			
Total Nameplate Rating 1,148.62 MW			

The above is a summary of the Nameplate rating for the CSPP projects under contract with Idaho Power as of December 31, 2019. 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

Project	MW	Contract On-Line Date	End Date
Wind projects			
Elkhorn Wind Project	101	December 2007	December 2027
Total Wind Nameplate Rating	**101**		
Geothermal Projects			
Raft River Unit 1	13	April 2008	April 2033
Neal Hot Springs	22	November 2012	November 2037
Total Geothermal Nameplate Rating	**35**		
Solar projects			
Jackpot Solar Facility	120	December 2022	Estimated
Total Solar Nameplate Rating	**120**		
Total Nameplate Rating	**256**		

The above is a summary of the Nameplate rating for the CSPP projects under contract with Idaho Power as of December 31, 2019. 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.

Flow Modeling

Models

Idaho Power uses two primary models to develop future flow scenarios for the IRP. The Snake River Planning Model (SRPM) is used to model surface water flows and the Enhanced Snake Plain Aquifer Model (ESPAM) is used to model 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 2019 IRP were derived, in part, from management practices outlined in an agreement between the Surface Water Coalition (SWC) 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. Model inputs also included a long-term analysis of trends in reach gains to the Snake River from Palisades Dam to King Hill. Weather modification activities conducted by Idaho Power and other participating entities were included in the modeling effort.

Recharge capacity modeled for the 2019 IRP included diversions with the capability of diverting all available water at the Snake River below Milner Dam during the winter months under typical release conditions. These diversions can have a significant impact to flows downstream of Milner Dam. Modeled recharge diversions peak at approximately 339,000 acre-ft in IRP year 2025. In IRP year 2025, approximately 145,000 acre-ft of recharge diversions occur above American Falls Reservoir and 195,000 acre-ft is diverted at Milner Dam. Modeled recharge diversions decline only slightly from the peak in 2025 through the end of the modeling period in 2038. The 2019 IRP included approximately 85,000 acre-ft of additional annual recharge not included in the 2017 IRP. This increase in projected recharge activity is based upon recharge activity observed from spring 2016 through spring 2018. The additional annual recharge volume can be attributed to the development of private aquifer recharge and state sponsored recharge demonstrating a higher level of recharge capacity than anticipated in the 2017 IRP.

System conversion projects involve the conversion of ground water supplied irrigated land to surface water-supplied irrigated land. The number of acres modeled and potential water savings was based on data provided by the Idaho Department of Water Resources and local ground water districts. The current model assumes a total of 48,000 acres of converted land on the ESPA. This is an increase of approximately 30,000 acres over the 2017 IRP and is based on data collected from a local groundwater district. Water savings for conversion projects are calculated at a rate of 2.0 acre-ft per converted acre. Diversions for conversion projects peak at approximately 95,000 acre-ft in model year 2024 and are held essentially constant through the end of the modeling period in year 2038.

The model accounted for a 190,000 acre-ft decrease in ground water pumping from the ESPA. The decrease was spread evenly over ground water irrigated lands that are subject to the agreement between the SWC and the IGWA. The SWC agreement requires a total reduction of 240,000 acre-ft per year but the agreement allows for a portion of that to be offset by aquifer recharge activities. Based on recent management activity, approximately 50,000 acre-ft per year reduction is accomplished through other forms of mitigation such as private aquifer recharge.

The 2019 IRP modeling also recognized ongoing declines in specific reaches. Future reach declines were determined using a variety of statistical analyses. Trend data indicate reach gains into American Falls Reservoir and from Lower Salmon Falls Dam to Bliss demonstrated a statistically significant decline for the period of 1988 to 2017. The long-term declines are still present, but they have improved since the 2017 IRP. Reach gains to the Snake River increased in 2016 and 2017. The increases in reach gains may be due to a combination of factors including recent high runoff events, good supply of irrigation water, and aquifer recharge activities. The declines calculated for the 2019 IRP are approximately 25 to 30 percent less than those used in the 2017 IRP. This results in additional water in the Snake River throughout the planning period.

Weather modification was added to the model at various levels of development. For IRP years 2019 through 2024, weather modification was increased to reflect projected levels of program development in Eastern Idaho, the Wood River and Boise basins. Beyond IRP year 2024, weather-modification levels in these three basins were held constant through the remainder of the IRP planning period. The level of weather modification was held constant at the current level in the Payette River Basin throughout the IRP planning period.

The modeling also accounts for changes in reach gains from observed water management activities on the ESPA since 2014. Reach gain calculations include management activities that have occurred since 2014. Data from IDWR and other sources were used to determine the magnitude of the management activities and the ESPAM was used to model the projected reach gains. The impact of those management activities can have impacts on reach gains for up to 30 years.

Model Results

The combined model allows for the inclusion of all future management activities, and the resulting reach gains from those management activities into Idaho Power’s 2019 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 (HCC), 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, directly impact the annual volume of water expected through the HCC as well as the timing and location of gains within the system.

Overall inflow to Brownlee Reservoir increases from IRP modeled year 2019 through 2024. Flows peak in 2025 with the 50 percent exceedance annual inflow to Brownlee Reservoir at just over 12.33 million acre-ft/year. In 2038, those flows declined to approximately 12.03 million acre-ft per year. For the April through July volume the peak occurs in modeled year 2024 with a volume of 5.58 million acre-ft. In the final modeled year of 2038, the April through July inflow to Brownlee decreases to 5.47 million acre-ft.

The Brownlee inflow volumes for the 2019 IRP are higher than those reported in the 2017 IRP. There are several factors leading to the increase in modeled flows. The change in reach declines had a significant impact on inflows to Brownlee Reservoir. For example, in model year 2036, the increase in Brownlee inflow volume attributable to changes in reach declines between the 2019 and 2017 IRPs is approximately 337,000 acre-feet, Weather modification volume increased by approximately 200,000 acre-ft per year in the 2019 IRP as compared to the 2017 IRP. The other notable change is the observed recharge conducted in 2016 and 2017 exceeded recharge volume assumptions made during the 2017 IRP.

Over 1,000,000 acre-ft water were recharged to the ESPA during 2016 and 2017. While outside the modeling period of 2019 to 2038, the reach gains resulting from this recharge are modeled and significantly increase reach gains for the modeling period. The modeled reach gains from this recharge increased reach gains in the Snake River and inflows to Brownlee Reservoir particularly during the first five years of the modeling period.

2019 Model Parameters (acre foot/year)

	Managed Recharge						Reach Declines	
Year	Above American Falls	Below American Falls	Total	Weather Modification	System Conversions	Ground Water Pumping Declines	American Falls Inflows	Below Milner Inflows
2019	145,210	192,991	338,201	978,140	96,138	190,053	167,239	135,702
2020	144,682	193,002	337,685	1,164,927	95,105	190,053	182,442	148,039
2021	144,559	193,002	337,562	1,232,907	95,105	190,053	197,646	160,375
2022	144,436	193,052	337,489	1,241,693	96,140	190,053	212,849	172,712
2023	144,680	193,298	337,978	1,252,091	95,105	190,053	228,053	185,049
2024	144,381	193,187	337,568	1,268,605	95,537	190,053	243,256	197,385
2025	144,319	194,802	339,121	1,268,605	94,928	190,053	258,460	209,722
2026	144,319	193,195	337,514	1,268,605	94,928	190,053	273,663	222,058
2027	144,319	193,139	337,459	1,268,605	94,928	190,053	288,867	234,395
2028	144,319	193,024	337,344	1,268,605	94,928	190,053	304,071	246,732
2029	144,319	192,913	337,233	1,268,605	94,928	190,053	319,274	259,068
2030	144,490	192,669	337,159	1,268,605	95,414	190,053	334,478	271,405
2031	143,631	192,550	336,181	1,268,605	95,351	190,053	349,681	283,741
2032	143,508	192,429	335,937	1,268,605	95,351	190,053	364,885	296,078
2033	143,693	192,364	336,056	1,268,605	95,412	190,053	380,088	308,414
2034	143,262	192,001	335,263	1,268,605	95,535	190,053	395,292	320,751
2035	143,865	192,058	335,924	1,268,605	95,535	190,053	410,495	333,088
2036	143,324	191,878	335,202	1,268,605	95,535	190,053	425,699	345,424
2037	143,139	191,691	334,831	1,268,605	95,291	190,053	440,902	357,761
2038	142,467	191,634	334,101	1,268,605	95,172	190,053	456,106	370,097

Hydro Modeling Results (aMW)

		50th Percentile			70th Percentile			90th Percentile		
Year	**Month**	**HCC***	**ROR****	**Total**	**HCC**	**ROR**	**Total**	**HCC**	**ROR**	**Total**
2019	Jan	750	350	1,100	596	204	800	434	177	612
	Feb	787	355	1,141	682	310	993	682	310	993
	Mar	815	276	1,092	588	225	813	588	225	813
	Apr	1,058	406	1,465	750	274	1,024	750	274	1,024
	May	913	432	1,344	875	320	1,195	875	320	1,195
	June	992	385	1,377	678	333	1,011	678	333	1,011
	July	551	292	842	520	282	802	520	282	802
	Aug	466	251	716	437	242	679	437	242	679
	Sept	568	241	809	464	231	696	464	231	696
	Oct	417	215	632	395	206	601	395	206	601
	Nov	343	195	538	347	180	527	347	180	527
	Dec	579	362	941	484	189	673	484	189	673
Annual aMW		**686**	**313**	**1,000**	**568**	**250**	**818**	**555**	**248**	**802**
2020	Jan	758	355	1,113	612	257	869	444	181	625
	Feb	803	365	1,168	689	321	1,010	689	321	1,010
	Mar	820	282	1,103	595	234	828	595	234	828
	Apr	1,072	426	1,498	761	290	1,051	761	290	1,051
	May	931	454	1,385	877	332	1,209	877	332	1,209
	June	1,010	431	1,441	704	335	1,039	704	335	1,039
	July	551	292	843	520	283	803	520	283	803
	Aug	467	251	717	437	243	680	437	243	680
	Sept	581	241	822	468	234	702	468	234	702
	Oct	414	216	629	391	206	597	391	206	597
	Nov	338	197	536	348	181	528	348	181	528
	Dec	584	374	958	486	190	675	486	190	675
Annual aMW		**694**	**324**	**1,018**	**574**	**259**	**833**	**560**	**252**	**812**

*HCC=Hells Canyon Complex, **ROR=Run of River

		50th Percentile			70th Percentile			90th Percentile		
Year	**Month**	**HCC***	**ROR****	**Total**	**HCC**	**ROR**	**Total**	**HCC**	**ROR**	**Total**
2021	Jan	760	355	1,115	613	257	870	446	182	628
	Feb	803	365	1,168	690	320	1,010	690	320	1,010
	Mar	824	283	1,107	602	235	837	602	235	837
	Apr	1,084	428	1,512	769	292	1,061	769	292	1,061
	May	946	455	1,401	882	334	1,216	882	334	1,216
	June	1,024	432	1,456	708	336	1,044	708	336	1,044
	July	551	292	843	520	284	804	520	284	804
	Aug	467	251	718	438	244	682	438	244	682
	Sept	584	241	826	470	234	704	470	234	704
	Oct	415	216	631	390	207	597	390	207	597
	Nov	337	198	535	348	181	529	348	181	529
	Dec	585	376	961	487	190	677	487	190	677
Annual aMW		**698**	**324**	**1,023**	**576**	**259**	**836**	**562**	**253**	**816**
2022	Jan	760	355	1,115	613	260	873	446	182	628
	Feb	803	366	1,168	690	320	1,010	690	320	1,010
	Mar	824	284	1,107	602	235	837	602	235	837
	Apr	1,085	428	1,513	770	295	1,065	770	295	1,065
	May	946	458	1,404	882	336	1,217	882	336	1,217
	June	1,025	435	1,461	710	336	1,046	710	336	1,046
	July	551	292	843	520	284	804	520	284	804
	Aug	467	251	718	438	244	681	438	244	681
	Sept	585	241	826	470	234	704	470	234	704
	Oct	415	216	630	390	207	597	390	207	597
	Nov	337	198	535	347	181	528	347	181	528
	Dec	586	378	964	487	190	677	487	190	677
Annual aMW		**698**	**325**	**1,024**	**576**	**260**	**837**	**563**	**254**	**816**

Year	Month	50th Percentile HCC*	50th Percentile ROR**	50th Percentile Total	70th Percentile HCC	70th Percentile ROR	70th Percentile Total	90th Percentile HCC	90th Percentile ROR	90th Percentile Total
2023	Jan	759	356	1,115	613	265	877	445	182	628
	Feb	802	366	1,168	689	320	1,009	689	320	1,009
	Mar	824	285	1,109	601	236	837	601	236	837
	Apr	1,084	428	1,513	769	298	1,068	769	298	1,068
	May	945	461	1,406	882	339	1,221	882	339	1,221
	June	1,032	441	1,472	711	338	1,049	711	338	1,049
	July	551	292	843	520	284	804	520	284	804
	Aug	467	251	718	437	244	681	437	244	681
	Sept	586	241	827	469	234	703	469	234	703
	Oct	415	216	631	390	207	597	390	207	597
	Nov	335	198	533	347	181	529	347	181	529
	Dec	586	380	966	487	190	678	487	190	678
Annual aMW		**699**	**326**	**1,025**	**576**	**261**	**838**	**562**	**254**	**817**
2024	Jan	759	357	1,116	613	271	884	445	182	627
	Feb	802	366	1,168	688	320	1,007	688	320	1,007
	Mar	824	286	1,110	601	236	837	601	236	837
	Apr	1,085	429	1,513	770	300	1,070	770	300	1,070
	May	947	463	1,409	882	341	1,223	882	341	1,223
	June	1,033	444	1,477	712	338	1,050	712	338	1,050
	July	550	292	842	519	284	803	519	284	803
	Aug	466	251	717	437	244	681	437	244	681
	Sept	586	241	828	468	234	703	468	234	703
	Oct	415	215	630	390	207	596	390	207	596
	Nov	335	198	533	348	181	529	348	181	529
	Dec	586	381	968	487	190	678	487	190	678
Annual aMW		**699**	**327**	**1,026**	**576**	**262**	**838**	**562**	**255**	**817**

Year	Month	50th Percentile HCC*	ROR**	Total	70th Percentile HCC	ROR	Total	90th Percentile HCC	ROR	Total
2025	Jan	759	356	1,115	612	268	880	444	182	627
	Feb	800	366	1,165	688	319	1,007	688	319	1,007
	Mar	823	286	1,109	600	235	835	600	235	835
	Apr	1,084	428	1,512	768	300	1,068	768	300	1,068
	May	946	462	1,409	882	341	1,223	882	341	1,223
	June	1,032	443	1,475	711	337	1,049	711	337	1,049
	July	550	292	842	519	284	803	519	284	803
	Aug	466	251	716	436	244	680	436	244	680
	Sept	584	241	825	467	234	701	467	234	701
	Oct	414	215	630	389	206	596	389	206	596
	Nov	336	198	534	348	181	529	348	181	529
	Dec	586	380	966	486	190	677	486	190	677
Annual aMW		**698**	**327**	**1,025**	**576**	**262**	**837**	**562**	**255**	**816**
2026	Jan	758	355	1,113	611	265	877	444	182	626
	Feb	797	365	1,162	687	319	1,006	687	319	1,006
	Mar	822	286	1,108	599	234	833	599	234	833
	Apr	1,083	428	1,511	769	300	1,068	769	300	1,068
	May	946	462	1,408	882	341	1,222	882	341	1,222
	June	1,032	443	1,474	711	337	1,048	711	337	1,048
	July	549	292	841	519	284	802	519	284	802
	Aug	465	251	716	436	244	680	436	244	680
	Sept	582	241	823	466	234	700	466	234	700
	Oct	413	215	628	389	206	596	389	206	596
	Nov	337	198	534	348	181	529	348	181	529
	Dec	584	378	962	485	190	675	485	190	675
Annual aMW		**697**	**326**	**1,023**	**575**	**261**	**836**	**561**	**254**	**815**

Year	Month	50th Percentile HCC*	50th Percentile ROR**	50th Percentile Total	70th Percentile HCC	70th Percentile ROR	70th Percentile Total	90th Percentile HCC	90th Percentile ROR	90th Percentile Total
2027	Jan	757	354	1,111	611	262	872	443	181	625
	Feb	792	364	1,156	685	318	1,003	685	318	1,003
	Mar	821	284	1,106	599	234	832	599	234	832
	Apr	1,082	427	1,509	767	299	1,066	767	299	1,066
	May	946	461	1,407	882	340	1,222	882	340	1,222
	June	1,031	441	1,472	710	337	1,047	710	337	1,047
	July	549	292	840	518	283	801	518	283	801
	Aug	465	251	715	435	243	679	435	243	679
	Sept	579	241	820	464	234	698	464	234	698
	Oct	412	215	627	390	206	596	390	206	596
	Nov	337	198	535	347	181	528	347	181	528
	Dec	583	376	959	485	190	675	485	190	675
Annual aMW		**696**	**325**	**1,021**	**574**	**261**	**835**	**560**	**254**	**814**
2028	Jan	756	353	1,109	610	258	868	443	181	623
	Feb	789	362	1,151	684	316	1,000	684	316	1,000
	Mar	820	283	1,102	598	232	830	598	232	830
	Apr	1,082	427	1,509	767	298	1,065	767	298	1,065
	May	945	460	1,404	882	339	1,221	882	339	1,221
	June	1,030	440	1,470	709	337	1,046	709	337	1,046
	July	548	291	840	517	283	800	517	283	800
	Aug	464	250	714	435	243	678	435	243	678
	Sept	576	241	817	463	234	697	463	234	697
	Oct	411	215	626	389	206	595	389	206	595
	Nov	338	198	536	347	181	528	347	181	528
	Dec	581	373	953	483	189	673	483	189	673
Annual aMW		**695**	**324**	**1,019**	**574**	**260**	**833**	**560**	**253**	**813**

Year	Month	50th Percentile HCC*	50th Percentile ROR**	50th Percentile Total	70th Percentile HCC	70th Percentile ROR	70th Percentile Total	90th Percentile HCC	90th Percentile ROR	90th Percentile Total
2029	Jan	755	352	1,107	609	253	861	441	180	621
	Feb	786	360	1,146	683	314	997	683	314	997
	Mar	819	281	1,100	596	230	826	596	230	826
	Apr	1,081	426	1,507	767	298	1,065	767	298	1,065
	May	944	456	1,400	881	338	1,219	881	338	1,219
	June	1,029	439	1,468	708	336	1,044	708	336	1,044
	July	548	291	839	517	283	800	517	283	800
	Aug	463	250	713	434	243	677	434	243	677
	Sept	573	240	813	461	233	694	461	233	694
	Oct	410	215	625	389	206	595	389	206	595
	Nov	339	197	537	347	181	528	347	181	528
	Dec	579	370	949	482	189	671	482	189	671
Annual aMW		**694**	**323**	**1,017**	**573**	**259**	**831**	**559**	**253**	**812**
2030	Jan	753	351	1,104	606	247	853	441	178	619
	Feb	783	359	1,141	682	312	994	682	312	994
	Mar	817	280	1,097	596	227	823	596	227	823
	Apr	1,079	426	1,505	766	297	1,063	766	297	1,063
	May	944	455	1,399	881	331	1,212	881	331	1,212
	June	1,026	436	1,462	707	335	1,041	707	335	1,041
	July	547	291	838	516	283	799	516	283	799
	Aug	463	250	712	434	243	676	434	243	676
	Sept	569	240	809	459	233	692	459	233	692
	Oct	410	215	625	390	206	595	390	206	595
	Nov	341	197	538	347	181	527	347	181	527
	Dec	577	366	943	481	189	670	481	189	670
Annual aMW		**692**	**322**	**1,014**	**572**	**257**	**829**	**558**	**251**	**809**

		50th Percentile			70th Percentile			90th Percentile		
Year	**Month**	**HCC***	**ROR****	**Total**	**HCC**	**ROR**	**Total**	**HCC**	**ROR**	**Total**
2031	Jan	752	349	1,101	601	241	842	440	177	617
	Feb	781	359	1,140	680	308	988	680	308	988
	Mar	816	279	1,095	595	225	819	595	225	819
	Apr	1,078	425	1,503	765	297	1,062	765	297	1,062
	May	944	454	1,398	881	332	1,212	881	332	1,212
	June	1,022	434	1,455	706	335	1,040	706	335	1,040
	July	546	291	837	515	283	798	515	283	798
	Aug	462	250	712	433	242	675	433	242	675
	Sept	566	240	806	453	232	686	453	232	686
	Oct	411	214	626	390	205	596	390	205	596
	Nov	340	197	536	346	180	527	346	180	527
	Dec	575	363	937	480	189	668	480	189	668
Annual aMW		**691**	**321**	**1,012**	**570**	**256**	**826**	**557**	**250**	**807**
2032	Jan	750	348	1,098	600	236	835	440	177	617
	Feb	779	358	1,136	679	306	985	679	306	985
	Mar	815	278	1,093	593	224	817	593	224	817
	Apr	1,077	424	1,501	765	295	1,060	765	295	1,060
	May	943	453	1,396	880	332	1,212	880	332	1,212
	June	1,017	432	1,448	705	335	1,040	705	335	1,040
	July	546	291	836	515	282	797	515	282	797
	Aug	462	249	711	432	242	674	432	242	674
	Sept	562	240	802	452	232	684	452	232	684
	Oct	413	214	627	390	205	595	390	205	595
	Nov	340	196	536	346	180	526	346	180	526
	Dec	573	359	931	478	189	667	478	189	667
Annual aMW		**690**	**320**	**1,010**	**569**	**255**	**824**	**556**	**250**	**806**

		50th Percentile			70th Percentile			90th Percentile		
Year	**Month**	**HCC***	**ROR****	**Total**	**HCC**	**ROR**	**Total**	**HCC**	**ROR**	**Total**
2033	Jan	749	347	1,096	599	230	829	438	177	615
	Feb	777	357	1,133	677	305	982	677	305	982
	Mar	814	277	1,090	592	223	815	592	223	815
	Apr	1,076	424	1,499	763	293	1,056	763	293	1,056
	May	942	452	1,395	880	330	1,210	880	330	1,210
	June	1,012	430	1,443	704	334	1,038	704	334	1,038
	July	545	291	836	514	282	796	514	282	796
	Aug	461	249	710	432	242	674	432	242	674
	Sept	558	240	798	450	232	682	450	232	682
	Oct	414	214	628	390	205	595	390	205	595
	Nov	341	196	537	346	180	526	346	180	526
	Dec	572	355	927	475	188	664	475	188	664
Annual aMW		**688**	**319**	**1,008**	**568**	**254**	**822**	**555**	**249**	**804**
2034	Jan	748	346	1,093	598	225	823	437	177	613
	Feb	775	356	1,131	676	304	980	676	304	980
	Mar	813	274	1,087	590	222	812	590	222	812
	Apr	1,074	423	1,497	763	291	1,053	763	291	1,053
	May	941	451	1,393	879	329	1,209	879	329	1,209
	June	1,011	429	1,440	702	334	1,036	702	334	1,036
	July	544	290	835	514	282	795	514	282	795
	Aug	460	249	709	431	242	673	431	242	673
	Sept	554	239	794	448	231	679	448	231	679
	Oct	416	214	630	391	205	596	391	205	596
	Nov	341	196	537	345	180	525	345	180	525
	Dec	571	350	921	473	188	661	473	188	661
Annual aMW		**687**	**318**	**1,005**	**567**	**253**	**820**	**554**	**249**	**803**

		50th Percentile			70th Percentile			90th Percentile		
Year	**Month**	**HCC***	**ROR****	**Total**	**HCC**	**ROR**	**Total**	**HCC**	**ROR**	**Total**
2035	Jan	746	344	1,091	598	219	817	436	176	612
	Feb	768	354	1,121	674	303	977	674	303	977
	Mar	811	273	1,084	589	221	809	589	221	809
	Apr	1,072	422	1,494	762	289	1,051	762	289	1,051
	May	941	450	1,391	879	329	1,208	879	329	1,208
	June	1,011	429	1,439	701	333	1,034	701	333	1,034
	July	544	290	834	513	282	794	513	282	794
	Aug	460	249	708	430	241	672	430	241	672
	Sept	550	239	789	446	231	677	446	231	677
	Oct	419	213	632	390	205	595	390	205	595
	Nov	340	195	535	345	180	525	345	180	525
	Dec	571	346	917	471	188	659	471	188	659
Annual aMW		**686**	**317**	**1,003**	**566**	**252**	**818**	**553**	**248**	**801**
2036	Jan	745	344	1,089	594	217	811	434	176	610
	Feb	765	351	1,117	673	301	975	673	301	975
	Mar	810	272	1,082	588	220	807	588	220	807
	Apr	1,072	421	1,493	761	288	1,048	761	288	1,048
	May	940	450	1,390	879	326	1,205	879	326	1,205
	June	1,009	427	1,437	699	333	1,032	699	333	1,032
	July	543	290	833	512	281	794	512	281	794
	Aug	459	248	707	430	241	671	430	241	671
	Sept	546	239	785	444	230	675	444	230	675
	Oct	420	213	633	390	204	595	390	204	595
	Nov	340	195	535	345	180	525	345	180	525
	Dec	570	341	911	471	188	658	471	188	658
Annual aMW		**685**	**316**	**1,001**	**565**	**251**	**816**	**552**	**247**	**800**

		50th Percentile			70th Percentile			90th Percentile		
Year	Month	HCC*	ROR**	Total	HCC	ROR	Total	HCC	ROR	Total
2037	Jan	743	343	1,086	592	215	806	433	175	608
	Feb	765	350	1,115	672	299	971	672	299	971
	Mar	809	270	1,079	585	217	802	585	217	802
	Apr	1,069	420	1,489	760	287	1,047	760	287	1,047
	May	940	449	1,388	879	326	1,204	879	326	1,204
	June	1,008	424	1,432	698	333	1,030	698	333	1,030
	July	542	290	832	511	281	793	511	281	793
	Aug	458	248	707	429	241	670	429	241	670
	Sept	544	239	783	442	230	672	442	230	672
	Oct	419	213	632	391	204	595	391	204	595
	Nov	340	194	534	346	179	525	346	179	525
	Dec	568	336	905	469	187	656	469	187	656
Annual aMW		**684**	**315**	**999**	**564**	**250**	**814**	**551**	**247**	**798**
2038	Jan	738	342	1,079	591	203	794	432	175	607
	Feb	762	351	1,113	670	295	964	670	295	964
	Mar	808	269	1,077	584	211	795	584	211	795
	Apr	1,067	419	1,487	759	286	1,045	759	286	1,045
	May	940	447	1,387	879	325	1,203	879	325	1,203
	June	1,023	423	1,445	696	332	1,029	696	332	1,029
	July	542	289	831	511	281	792	511	281	792
	Aug	458	248	706	428	241	669	428	241	669
	Sept	543	239	782	440	229	669	440	229	669
	Oct	418	213	631	391	204	594	391	204	594
	Nov	339	195	534	346	179	525	346	179	525
	Dec	568	331	899	468	187	655	468	187	655
Annual aMW		**684**	**314**	**997**	**564**	**248**	**811**	**550**	**245**	**796**

Long-Term Capacity Expansion Results (MW)

	Portfolio 1				Portfolio 13					
Gas Assumption:	Planning Gas Price				Planning Gas Price					
Carbon Assumption:	No Carbon Requirement				No Carbon Requirement					
B2H Assumption:	No B2H				B2H in Service 2026					
	Gas	**Solar**	**Battery**	**Coal Exit**	**Gas**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**B2H**
2019				(127)					(127)	
2020				(58)					(58)	
2021										
2022										
2023		120								
2024								5		
2025				(133)					(133)	
2026								5		500
2027										
2028								5		
2029		40	20							
2030		80	40							
2031		40								
2032	300									
2033										
2034				(708)					(708)	
2035	633	80	20		470	200	80	5		
2036						80				
2037	111				111			5		
2038										
Nameplate Total (MW)	1,044	360	80	(1,026)	581	280	80	25	(1,026)	500
Net Build	458				404					

	Portfolio 2					Portfolio 14					
Gas Assumption:	Planning Gas Price					Planning Gas Price					
Carbon Assumption:	Planning Carbon Requirement					Planning Carbon Requirement					
B2H Assumption:	No B2H					B2H in Service 2026					
	Gas	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**B2H**
2019					(127)					(127)	
2020					(58)					(58)	
2021											
2022					(177)					(177)	
2023		120					120		5		
2024									5		
2025					(133)					(133)	
2026		40	30						5		500
2027		40	20						5		
2028	300								5		
2029									5		
2030									5		
2031		40	10						5		
2032		80	20								
2033				5					5		
2034				5	(531)	300			5	(531)	
2035	578	40		5		300	160	30			
2036	111			5							
2037				5			40				
2038	56			5			40				
Nameplate Total (MW)	1,044	360	80	30	(1,026)	600	360	30	50	(1,026)	500
Net Build	488					514					

	Portfolio 3						Portfolio 15						
Gas Assumption:	Planning Gas Price						Planning Gas Price						
Carbon Assumption:	Generational Carbon Requirement						Generational Carbon Requirement						
B2H Assumption:	No B2H						B2H in Service 2026						
	Gas	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**B2H**
2019						(127)						(127)	
2020						(58)						(58)	
2021			725						640				
2022						(177)						(177)	
2023			120		5				120		5		
2024		100			5			100			5		
2025		100	120		5	(133)					5	(133)	
2026		100	120	30	5	(180)					5	(180)	500
2027	300	100	80	50	5			100	280	80	5		
2028		100			5	(174)		100			5	(174)	
2029					5						5		
2030					5	(177)			120		5	(177)	
2031	300				5		300						
2032					5						5		
2033	111												
2034			5										
2035	111												
2036													
2037	56						111						
2038	56										5		
Nameplate Total (MW)	933	500	1,170	80	50	(1,026)	411	300	1,160	80	50	(1,026)	500
Net Build	1,707						1,475						

	Portfolio 4						Portfolio 16						
Gas Assumption:	Planning Gas Price						Planning Gas Price						
Carbon Assumption:	High Carbon Requirement						High Carbon Requirement						
B2H Assumption:	No B2H						B2H in Service 2026						
	Gas	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**B2H**
2019						(127)						(127)	
2020						(58)						(58)	
2021			720						640				
2022						(177)						(177)	
2023			120						120				
2024													
2025		100	80			(133)		100				(133)	
2026		100	40	30		(180)		100				(180)	500
2027		100	200	50				100	200	80			
2028		100				(174)		100	200			(174)	
2029	300	100						100					
2030		100	5			(177)		100	5			(177)	
2031	300		5				300				5		
2032											5		
2033	111				5						5		
2034					5						5		
2035	111				5						5		
2036					5						5		
2037	56				5		111						
2038	56				5								
Nameplate Total (MW)	933	600	1,170	80	30	(1,026)	411	600	1,165	80	30	(1,026)	500
Net Build	1,787						1,760						

	Portfolio 5					Portfolio 17					
Gas Assumption:	Mid-Level Gas Price					Mid-Level Gas Price					
Carbon Assumption:	No Carbon Requirement					No Carbon Requirement					
B2H Assumption:	No B2H					B2H in Service 2026					
	Gas	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**B2H**
2019					(127)					(127)	
2020					(58)					(58)	
2021											
2022											
2023		120							5		
2024									5		
2025					(133)				5	(133)	
2026									5		500
2027				5							
2028				5							
2029			5	5							
2030		85	50	5							
2031		40	10	5							
2032		80	20	5							
2033	300			5							
2034				5	(708)					(708)	
2035	522	205		5		411	320	80			
2036	56			5		300					
2037	56								5		
2038	111								5		
Nameplate Total (MW)	1,044	530	85	50	(1,026)	711	320	80	30	(1,026)	500
Net Build	683					615					

	Portfolio 6						Portfolio 18					
Gas Assumption:	Mid-Level Gas Price						Mid-Level Gas Price					
Carbon Assumption:	Planning Carbon Requirement						Planning Carbon Requirement					
B2H Assumption:	No B2H						B2H in Service 2026					
	Gas	**Solar**	**Battery**	**Nuclear**	**Demand Response**	**Coal Exit**	**Gas**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**B2H**
2019						(127)					(127)	
2020						(58)					(58)	
2021												
2022											(177)	
2023		120						120		5		
2024												
2025						(133)				5	(133)	
2026										5		500
2027										5		
2028										5		
2029		40								5		
2030		40	30							5		
2031		80	30									
2032		80	20									
2033				60	5	(177)						
2034	300				5	(531)				5	(531)	
2035	467	245			5		300	525	80			
2036	56				5		56			5		
2037	111				5		300					
2038					5							
Nameplate Total (MW)	933	605	80	60	30	(1,026)	656	645	80	45	(1,026)	500
Net Build	682						900					

	Portfolio 7						Portfolio 19						
Gas Assumption:	Mid-Level Gas Price						Mid-Level Gas Price						
Carbon Assumption:	Generational Carbon Requirement						Generational Carbon Requirement						
B2H Assumption:	No B2H						B2H in Service 2026						
	Gas	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**B2H**
2019						(127)						(127)	
2020						(58)						(58)	
2021		100	720					100	600				
2022		100	80	30		(177)		100				(177)	
2023		100	200					100	120				
2024		100											
2025		100				(133)						(133)	
2026	300	100				(180)						(180)	500
2027			160	50				100	440	80			
2028						(174)		100		10		(174)	
2029								100		10			
2030			5			(177)	111		5	5		(177)	
2031	300		5						5		5		
2032											5		
2033	111				5		300				5		
2034					5						5		
2035	56				5						5		
2036	111				5						5		
2037					5						5		
2038	56				5						5		
Nameplate Total (MW)	933	600	1,170	80	30	(1,026)	411	600	1,170	105	40	(1,026)	500
Net Build	1,787						1,800						

	Portfolio 8						Portfolio 20							
Gas Assumption:	Mid-Level Gas Price						Mid-Level Gas Price							
Carbon Assumption:	High Carbon Requirement						High Carbon Requirement							
B2H Assumption:	No B2H						B2H in Service 2026							
	Gas	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Wind**	**Solar**	**Battery**	**Biomass**	**Demand Response**	**Coal Exit**	**B2H**
2019						(127)							(127)	
2020						(58)							(58)	
2021			720						600					
2022		100	40			(177)		100					(177)	
2023		100	160	30	5			100	120					
2024		100	40	20	5			100						
2025		100	80		5	(133)		100					(133)	
2026		100	120	30	5	(180)						5	(180)	500
2027		100			5			100	320	50				
2028	300				5	(174)		100						
2029			5		5									
2030					5	(177)			80	5	30		(177)	
2031	300		5		5				45	40				
2032					5					10				
2033	111									5		5		
2034												5	(174)	
2035	170						300					5		
2036												5		
2037												5		
2038	56						111					5		
Nameplate Total (MW)	937	600	1,170	80	50	(1,026)	411	600	1,165	110	30	35	(1,026)	500
Net Build	1,811						1,825							

	Portfolio 9					
Gas Assumption:	High Gas Price					
Carbon Assumption:	Zero Carbon Requirement					
B2H Assumption:	No B2H					
	Gas	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**
2019						(127)
2020						(58)
2021			40			
2022						
2023			120		5	
2024					5	
2025			40	30		(133)
2026			40	20		
2027			120	30		
2028						
2029					5	
2030			5		5	
2031					5	
2032					5	
2033			200		5	
2034	300				5	(708)
2035	692		605		5	
2036					5	
2037						
2038						
Nameplate Total (MW)	992		1,170	80	50	(1,026)
Net Build	1,266					

	Portfolio 21							
Gas Assumption:	High Gas Price							
Carbon Assumption:	Zero Carbon Requirement							
B2H Assumption:	B2H in Service 2026							
	Gas	**Wind**	**Solar**	**Battery**	**Nuclear**	**Demand Response**	**Coal Exit**	**B2H**
2019							(127)	
2020							(58)	
2021								
2022								
2023						5		
2024						5		
2025						5	(133)	
2026						5		500
2027						5		
2028								
2029								
2030			120					
2031			480					
2032			240					
2033		100	40	30				
2034		100	40	10			(708)	
2035	300	100	125	40				
2036					60			
2037					120			
2038						5		
Nameplate Total (MW)	300	300	1,045	80	180	30	(1,026)	500
Net Build	1,409							

	Portfolio 10						Portfolio 22						
Gas Assumption:	High Gas Price						High Gas Price						
Carbon Assumption:	Planning Carbon Requirement						Planning Carbon Requirement						
B2H Assumption:	No B2H						B2H in Service 2026						
	Gas	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**B2H**
2019						(127)						(127)	
2020						(58)						(58)	
2021			720										
2022													
2023			120		5						5		
2024					5						5		
2025			40	30	5	(133)					5	(133)	
2026			40	20	5						5		500
2027		100	120	30	5						5		
2028		100	120		5						5		
2029		100			5						5		
2030		100			5				120		5		
2031		100			5			100	520		5		
2032		100			5			100	160		5		
2033								100	80	30			
2034						(708)		100	40	10		(708)	
2035	748		5				300	100	125	40			
2036	56						300	100					
2037	300												
2038													
Nameplate Total (MW)	1,103	600	1,165	80	50	(1,026)	600	600	1,045	80	50	(1,026)	500
Net Build	1,972						1,849						

	Portfolio 11							**Portfolio 23**							
Gas Assumption:	High Gas Price							High Gas Price							
Carbon Assumption:	Generational Carbon Requirement							Generational Carbon Requirement							
B2H Assumption:	No B2H							B2H in Service 2026							
	Gas	**Wind**	**Solar**	**Battery**	**Biomass**	**Demand Response**	**Coal Exit**	**Gas**	**Wind**	**Solar**	**Battery**	**Biomass**	**Demand Response**	**Coal Exit**	**B2H**
2019							(127)							(127)	
2020							(58)							(58)	
2021		200	720						100	560					
2022		200	120				(177)		100					(177)	
2023		200	245	50					100	120			5		
2024		200							100				5		
2025	111	200					(133)		100				5	(133)	
2026	111	200											5	(180)	500
2027			40	20	30		(180)		200	360	60				
2028					30		(174)	111	100					(174)	
2029					30				100	40	20				
2030			40	10	30			56	100					(177)	
2031			5					167	100	85	5				
2032							(177)		100		5				
2033	300					5					5				
2034						5					5				
2035	170					5					5	30			
2036					30	5					10	30			
2037					30	5					5				
2038					30	5		300							
Nameplate Total (MW)	692	1,200	1,170	80	210	30	(1,026)	633	1,200	1,165	120	60	20	(1,026)	500
Net Build	2,356							2,672							

	Portfolio 12							Portfolio 24							
Gas Assumption:	High Gas Price							High Gas Price							
Carbon Assumption:	High Carbon Requirement							High Carbon Requirement							
B2H Assumption:	No B2H							B2H in Service 2026							
	Gas	**Wind**	**Solar**	**Battery**	**Biomass**	**Demand Response**	**Coal Exit**	**Gas**	**Wind**	**Solar**	**Battery**	**Biomass**	**Demand Response**	**Coal Exit**	**B2H**
2019							(127)							(127)	
2020							(58)							(58)	
2021		100	720						100	560					
2022		100	120				(177)		100					(177)	
2023		100	120						100	120					
2024		200	125	30					100						
2025		200			30		(133)		100					(133)	
2026		200	80	50	30		(180)							(180)	500
2027	111	100			30				200	400	90				
2028	111	100			30		(174)		100	85	10			(174)	
2029		100			30				100		10	30			
2030					30				100		10	30	5	(177)	
2031			5			5		222	100		10	30	5		
2032	300					5			100		10	30			
2033						5	(177)			5			5		
2034						5		111					5		
2035	170					5							5		
2036						5							5		
2037						5					10				
2038						5					10				
Nameplate Total (MW)	692	1,200	1,170	80	180	40	(1,026)	333	1,200	1,170	160	120	30	(1,026)	500
Net Build	2,336							2,487							

Manually Built Portfolio Results (MW)

	Portfolio 2(1)					Portfolio 14(1)					
Gas Assumption:	Planning Gas Price					Planning Gas Price					
Carbon Assumption:	Planning Carbon Requirement					Planning Carbon Requirement					
B2H Assumption:	No B2H					B2H in Service 2026					
	Gas	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**B2H**
2019					(127)					(127)	
2020					(58)					(58)	
2021											
2022					(177)					(177)	
2023		120					120		5		
2024									5		
2025					(133)					(133)	
2026	300				(180)				5	(180)	500
2027									5		
2028		40	30						5		
2029		40	20						5		
2030		80	10						5		
2031		120	10						5		
2032	56						80				
2033	111			5		300			5		
2034				5	(351)		40	10	5	(351)	
2035	522			5		300		10			
2036	56			5							
2037				5							
2038		40		5			160	10			
Nameplate Total (MW)	1,044	440	70	30	(1,026)	600	400	30	50	(1,026)	500
Net Build	558					554					

	Portfolio 2(2)					Portfolio 14(2)					
Gas Assumption:	Planning Gas Price					Planning Gas Price					
Carbon Assumption:	Planning Carbon Requirement					Planning Carbon Requirement					
B2H Assumption:	No B2H					B2H in Service 2026					
	Gas	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**B2H**
2019					(127)					(127)	
2020					(58)					(58)	
2021											
2022					(177)					(177)	
2023		120					120		5		
2024									5		
2025					(133)					(133)	
2026	300				(180)				5	(180)	500
2027									5		
2028	167	40			(174)				5	(174)	
2029		80	30				40	30	5		
2030		80	20				80	20	5		
2031	56	40					120	10	5		
2032		80	20				80	20			
2033	300			5		300					
2034				5	(177)					(177)	
2035	111			5		300					
2036				5							
2037	111			5							
2038				5							
Nameplate Total (MW)	1,044	440	70	30	(1,026)	600	440	80	40	(1,026)	500
Net Build	558					634					

	Portfolio 2(3)					Portfolio 14(3)					
Gas Assumption:	Planning Gas Price					Planning Gas Price					
Carbon Assumption:	Planning Carbon Requirement					Planning Carbon Requirement					
B2H Assumption:	No B2H					B2H in Service 2026					
	Gas	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**B2H**
2019					(127)					(127)	
2020					(58)					(58)	
2021											
2022					(177)					(177)	
2023		120					120				
2024											
2025					(133)					(133)	
2026		40									500
2027		80	30								
2028	300				(174)					(174)	
2029											
2030		40	20								
2031		120	30								
2032	56						40	30			
2033	56			5		56			5		
2034		120		5	(357)		80	10	5	(357)	
2035	411			5		411			5		
2036	111			5		56			5		
2037	111			5		111			5		
2038				5			40	10	5		
Nameplate Total (MW)	1,044	520	80	30	(1,026)	633	280	50	30	(1,026)	500
Net Build	648					467					

	Portfolio 2(4)					Portfolio 14(4)					
Gas Assumption:	Planning Gas Price					Planning Gas Price					
Carbon Assumption:	Planning Carbon Requirement					Planning Carbon Requirement					
B2H Assumption:	No B2H					B2H in Service 2026					
	Gas	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**B2H**
2019					(127)					(127)	
2020					(58)					(58)	
2021											
2022					(177)					(177)	
2023		120					120		5		
2024									5		
2025					(133)					(133)	
2026	300				(180)				5	(180)	500
2027									5		
2028	111	80	50		(174)				5	(174)	
2029		80	10				80	10	5		
2030	300				(177)	300			5	(177)	
2031									5		
2032	56						80	10			
2033		80	20	5			80	30	5		
2034	56			5		300			5		
2035	111			5							
2036				5							
2037	111			5							
2038				5							
Nameplate Total (MW)	1,044	360	80	30	(1,026)	600	360	50	50	(1,026)	500
Net Build	488					534					

	Portfolio 2(5)					Portfolio 14(5)					
Gas Assumption:	Planning Gas Price					Planning Gas Price					
Carbon Assumption:	Planning Carbon Requirement					Planning Carbon Requirement					
B2H Assumption:	No B2H					B2H in Service 2026					
	Gas	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**B2H**
2019					(127)					(127)	
2020					(58)					(58)	
2021											
2022											
2023		120			(177)		120		5	(177)	
2024									5		
2025					(133)					(133)	
2026	300				(180)				5	(180)	500
2027									5		
2028	111	80	50		(174)				5	(174)	
2029		80	10				80	10	5		
2030	300				(177)	300			5	(177)	
2031									5		
2032	56						80	10			
2033		80	20	5			80	30	5		
2034	56			5		300			5		
2035	111			5							
2036				5							
2037	111			5							
2038				5							
Nameplate Total (MW)	1,044	360	80	30	(1,026)	600	360	50	50	(1,026)	500
Net Build	488					534					

	Portfolio 2(6)					Portfolio 14(6)					
Gas Assumption:	Planning Gas Price					Planning Gas Price					
Carbon Assumption:	Planning Carbon Requirement					Planning Carbon Requirement					
B2H Assumption:	No B2H					B2H in Service 2026					
	Gas	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**B2H**
2019					(127)					(127)	
2020					(58)					(58)	
2021											
2022											
2023		120					120		5		
2024					(177)				5	(177)	
2025					(133)					(133)	
2026	300				(180)				5	(180)	500
2027									5		
2028	111	80	50		(174)				5	(174)	
2029		80	10				80	10	5		
2030	300				(177)	300			5	(177)	
2031									5		
2032	56						80	10			
2033		80	20	5			80	30	5		
2034	56			5		300			5		
2035	111			5							
2036				5							
2037	111			5							
2038				5							
Nameplate Total (MW)	1,044	360	80	30	(1,026)	600	360	50	50	(1,026)	500
Net Build	488					534					

	Portfolio 4(1)					Portfolio 16(1)						
Gas Assumption:	Planning Gas Price					Planning Gas Price						
Carbon Assumption:	High Carbon Requirement					High Carbon Requirement						
B2H Assumption:	No B2H					B2H in Service 2026						
	Gas	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**B2H**
2019					(127)						(127)	
2020					(58)						(58)	
2021												
2022					(177)						(177)	
2023		120						120				
2024												
2025					(133)						(133)	
2026	111	80	50		(180)						(180)	500
2027		160										
2028		120	20									
2029	300											
2030												
2031										5		
2032								40	30	5		
2033				5		111		80	20	5		
2034	111	80	10	5	(351)			80	10	5	(351)	
2035	300			5		300				5		
2036		600		5				80	20	5		
2037	56			5				320				
2038	56			5			300	440				
Nameplate Total (MW)	933	1,160	80	30	(1,026)	411	300	1,160	80	30	(1,026)	500
Net Build	1,177					1,455						

	Portfolio 4(2)					Portfolio 16(2)						
Gas Assumption:	Planning Gas Price					Planning Gas Price						
Carbon Assumption:	High Carbon Requirement					High Carbon Requirement						
B2H Assumption:	No B2H					B2H in Service 2026						
	Gas	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**B2H**
2019					(127)						(127)	
2020					(58)						(58)	
2021												
2022					(177)						(177)	
2023		120						120				
2024												
2025					(133)						(133)	
2026	111	80	50		(180)						(180)	500
2027		200	10									
2028	300				(174)						(174)	
2029								40	30			
2030		80	20					160	50			
2031		120								5		
2032	111							120		5		
2033				5		111				5		
2034		560		5	(177)					5	(177)	
2035	300			5		300				5		
2036				5				280		5		
2037	56			5								
2038	56			5			300	440				
Nameplate Total (MW)	933	1,160	80	30	(1,026)	411	300	1,160	80	30	(1,026)	500
Net Build	1,177					1,455						

	Portfolio 4(3)					Portfolio 16(3)						
Gas Assumption:	Planning Gas Price					Planning Gas Price						
Carbon Assumption:	High Carbon Requirement					High Carbon Requirement						
B2H Assumption:	No B2H					B2H in Service 2026						
	Gas	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**B2H**
2019					(127)						(127)	
2020					(58)						(58)	
2021												
2022					(177)						(177)	
2023		120						120				
2024												
2025					(133)						(133)	
2026		40										500
2027		80	30									
2028	300				(174)						(174)	
2029												
2030		40	20									
2031		120	20							5		
2032		240						40	30	5		
2033	111			5		111				5		
2034				5	(357)					5	(357)	
2035	356	520	10	5		300		160	30	5		
2036	56			5				80	20	5		
2037	111			5				320				
2038				5			300	440				
Nameplate Total (MW)	933	1,160	80	30	(1,026)	411	300	1,160	80	30	(1,026)	500
Net Build	1,177					1,455						

	Portfolio 4(4)					Portfolio 16(4)						
Gas Assumption:	Planning Gas Price					Planning Gas Price						
Carbon Assumption:	High Carbon Requirement					High Carbon Requirement						
B2H Assumption:	No B2H					B2H in Service 2026						
	Gas	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**B2H**
2019					(127)						(127)	
2020					(58)						(58)	
2021												
2022					(177)						(177)	
2023		120						120				
2024												
2025					(133)						(133)	
2026	111	80	50		(180)						(180)	500
2027		160										
2028	300				(174)						(174)	
2029								40	30			
2030	300				(177)	300					(177)	
2031										5		
2032		80	20					80	10	5		
2033		240		5				80	20	5		
2034		480	10	5				80	20	5		
2035	56			5		111				5		
2036	56			5						5		
2037	111			5				320				
2038				5			300	440				
Nameplate Total (MW)	933	1,160	80	30	(1,026)	411	300	1,160	80	30	(1,026)	500
Net Build	1,177					1,455						

OREGON CARBON EMISSION FORECAST

Idaho Power anticipates the 2019 IRP carbon emission forecast will be used to establish a target for Idaho Power compliance with the proposed Oregon Cap and Trade Legislation. Idaho Power carefully reviewed historical emissions and emissions assumptions in the portfolio modeling and output.

The Total Carbon Dioxide (CO_2) Emissions forecast is composed of results from the AURORA modeling, policy adjustments to IRP forecast assumptions and a Market Volatility adjustment. The modeled AURORA resource dispatch from Idaho Power's preferred resource portfolio, Portfolio 14, is the basis for the emissions forecast. The AURORA emissions forecast consists of the emissions from the modeled operation of Idaho Power's resources and emissions based on forecasted purchased energy. Emissions from forecasted purchased energy is estimated to contribute 0.47 short tons per MWh, which is in-line with the unspecified market purchases used by the California Air Resource Board in their Cap and Trade program.

The hydro forecast in the 2019 IRP AURORA modeling assumes future increases in hydro generation based on expansion of Idaho Power's cloud seeding program and certain State of Idaho groundwater management activities. The actual results from these hydro generation programs may not result in the forecasted increase in generation. Cloud seeding expansion is subject to regulatory review and funding and therefore, was removed from carbon forecast modeling. Groundwater management activities, such as managed aquifer recharge has exceeded the State of Idaho's goals in 2017 and 2018, resulting in reduced wintertime hydro generation production. Idaho Power is concerned that trend may continue and thus feels that carbon forecast modeling should use a more conservative hydrogeneration assumption.

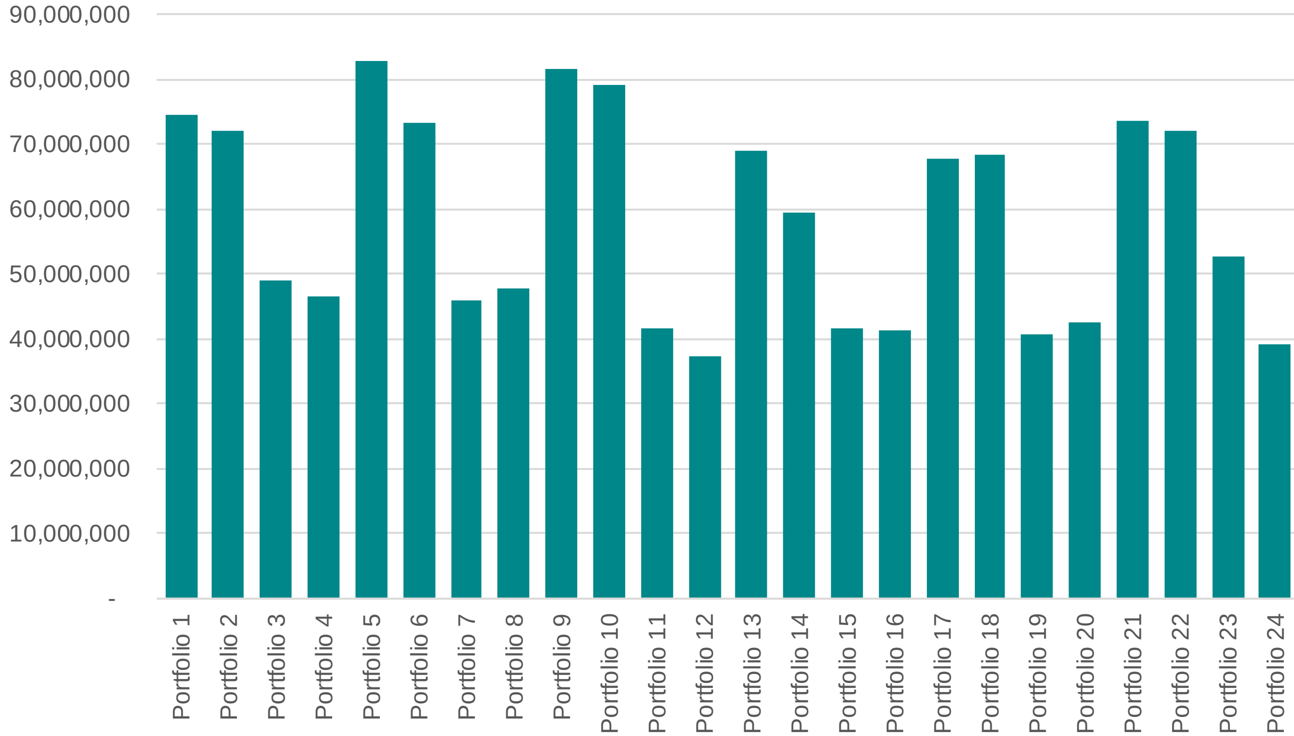
Lastly, Idaho Power reviewed recent system operations, resource dispatch and associated carbon emissions as well as the near-term operational forecasts. This review resulted in an Market Forecast Volatility adjustment to reconcile the discrepancy in emissions forecasts between the IRP and near-term operational planning. Examples of events that may drive market volatility: unplanned system outages (Idaho Power's system and surrounding system), extreme weather events, supply interruptions or limitations, natural disaster, etc.

Year	Resource CO_2 Emissions	Market Purchases CO^2	Hydro Policy Implementation Uncertainty Adjustment	Market Volatility Adjustment	Total System CO_2 Emissions	Oregon CO_2 Emissions
2019	4,100,667	287,475	329,686	190,859	4,908,687	223,856
2020	4,206,718	274,662	481,180	190,859	5,153,420	234,266
2021	4,165,188	350,488	541,259	190,859	5,247,795	237,805
2022	4,423,053	349,999	566,011	190,859	5,529,922	249,326
2023	3,932,304	436,275	586,927	190,859	5,146,365	230,902
2024	3,932,231	535,493	609,505	190,859	5,268,088	234,467
2025	4,323,190	524,129	617,935	190,859	5,656,114	250,654
2026	3,935,017	792,624	626,016	–	5,353,657	236,474
2027	3,535,890	879,349	631,418	–	5,046,658	222,285
2028	3,538,173	1,003,592	637,980	–	5,179,745	227,147
2029	2,345,650	1,480,651	643,882	–	4,470,182	195,093
2030	2,610,779	933,734	646,328	–	4,190,841	182,229
2031	1,687,670	1,432,465	651,605	–	3,771,741	163,443
2032	1,610,320	1,506,697	659,269	–	3,776,286	163,062
2033	1,671,532	1,599,885	672,911	–	3,944,327	169,880
2034	1,678,076	1,610,612	682,302	–	3,970,991	170,314
2035	1,848,815	1,527,210	693,035	–	4,069,059	173,587
2036	1,843,975	1,588,386	708,991	–	4,141,353	175,661
2037	1,833,284	1,550,450	687,647	–	4,071,380	171,707
2038	1,787,418	998,475	678,607	–	3,464,501	145,355

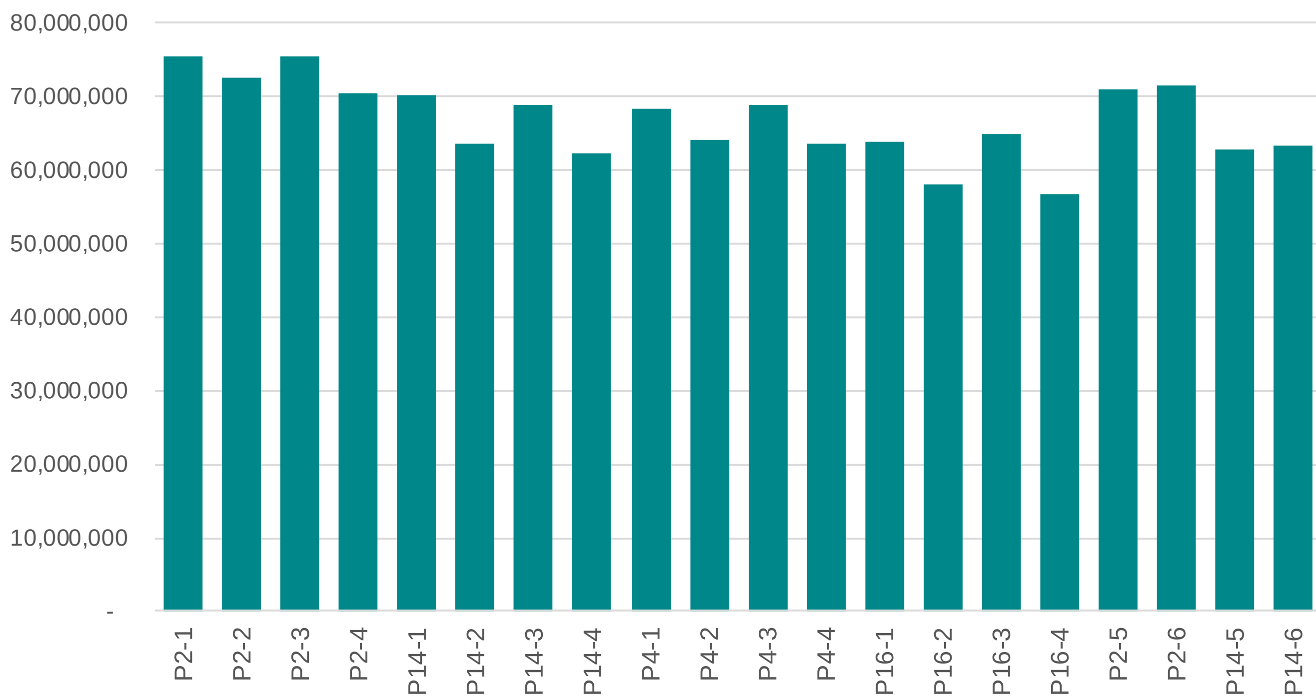
Portfolio Generating Resource Emissions

CO_2 Tons

WECC-Optimized Portfolios

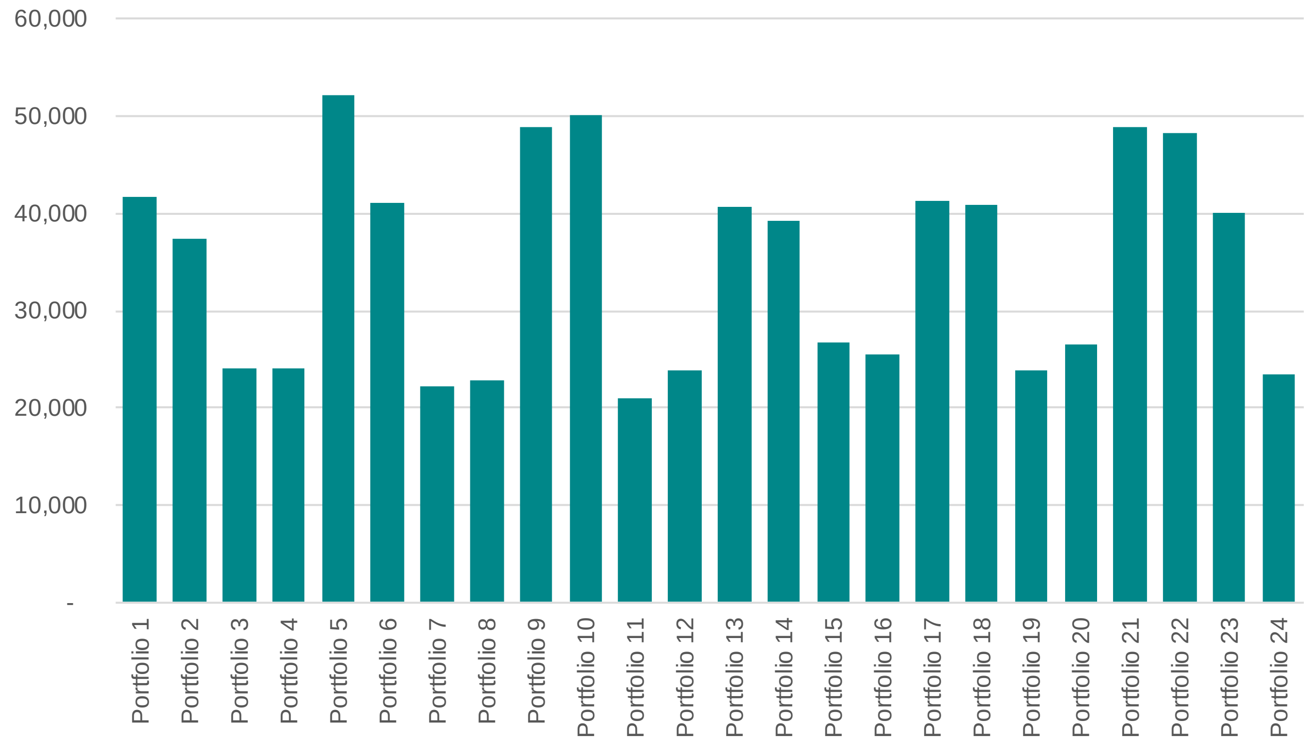


Manually Built Portfolios

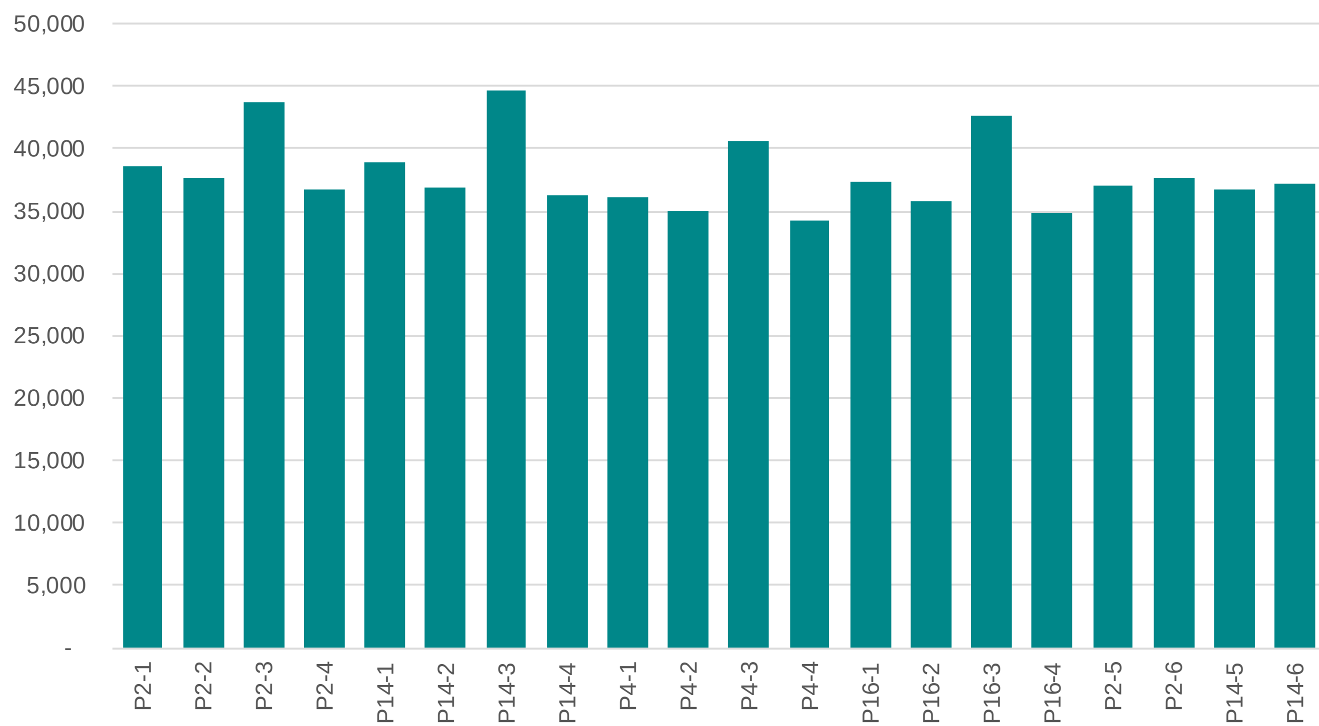


NOx Tons

WECC-Optimized Portfolios



Manually Built Portfolios



HG Tons

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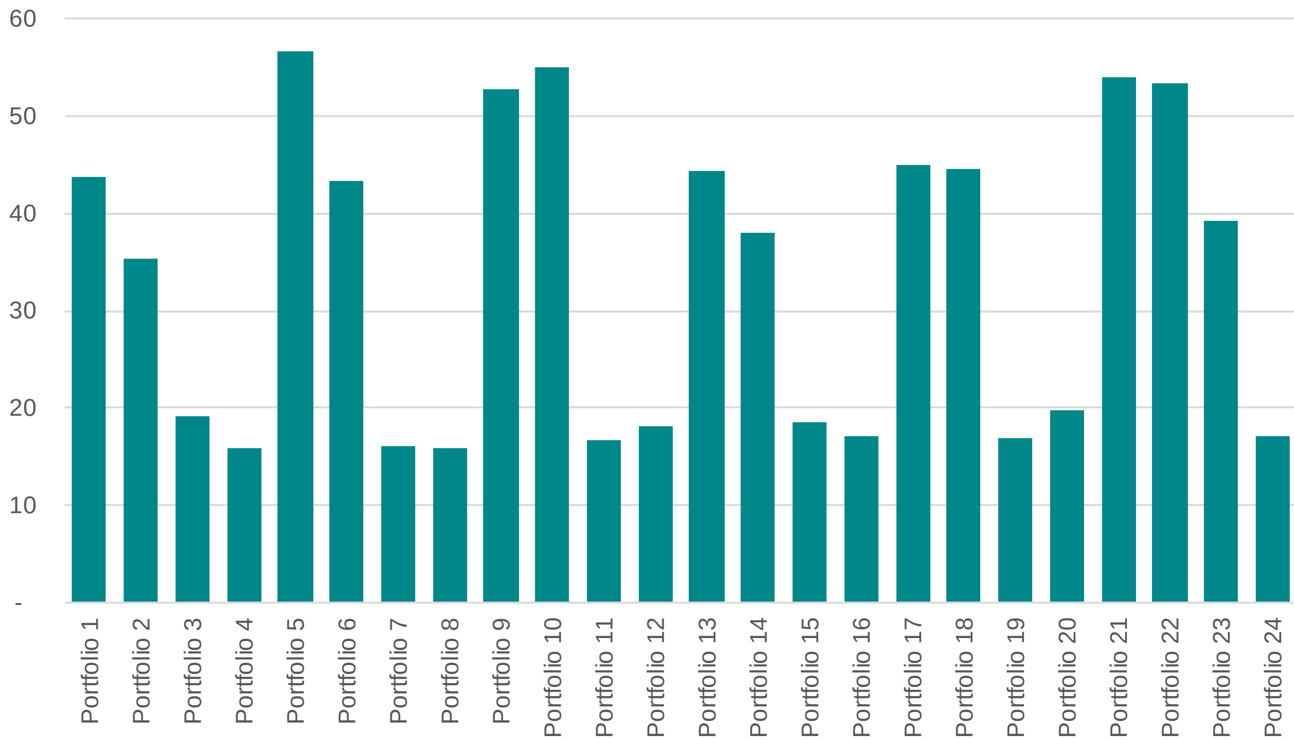

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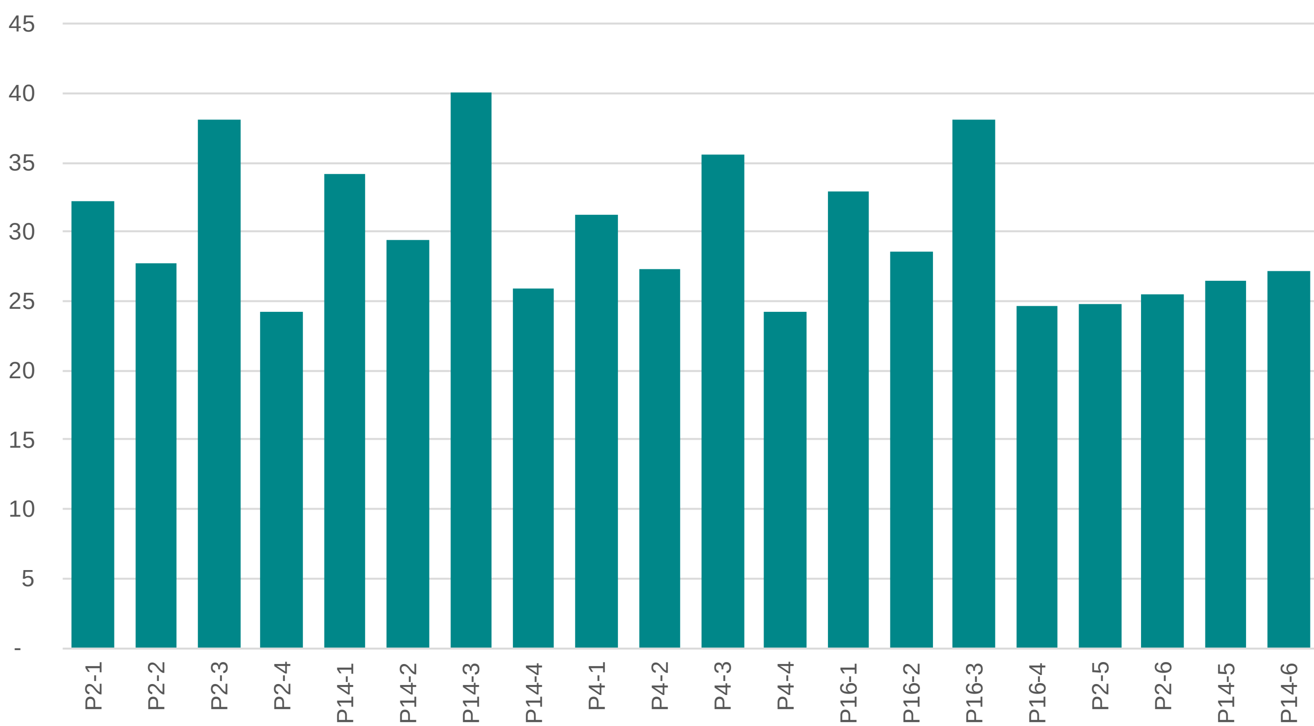
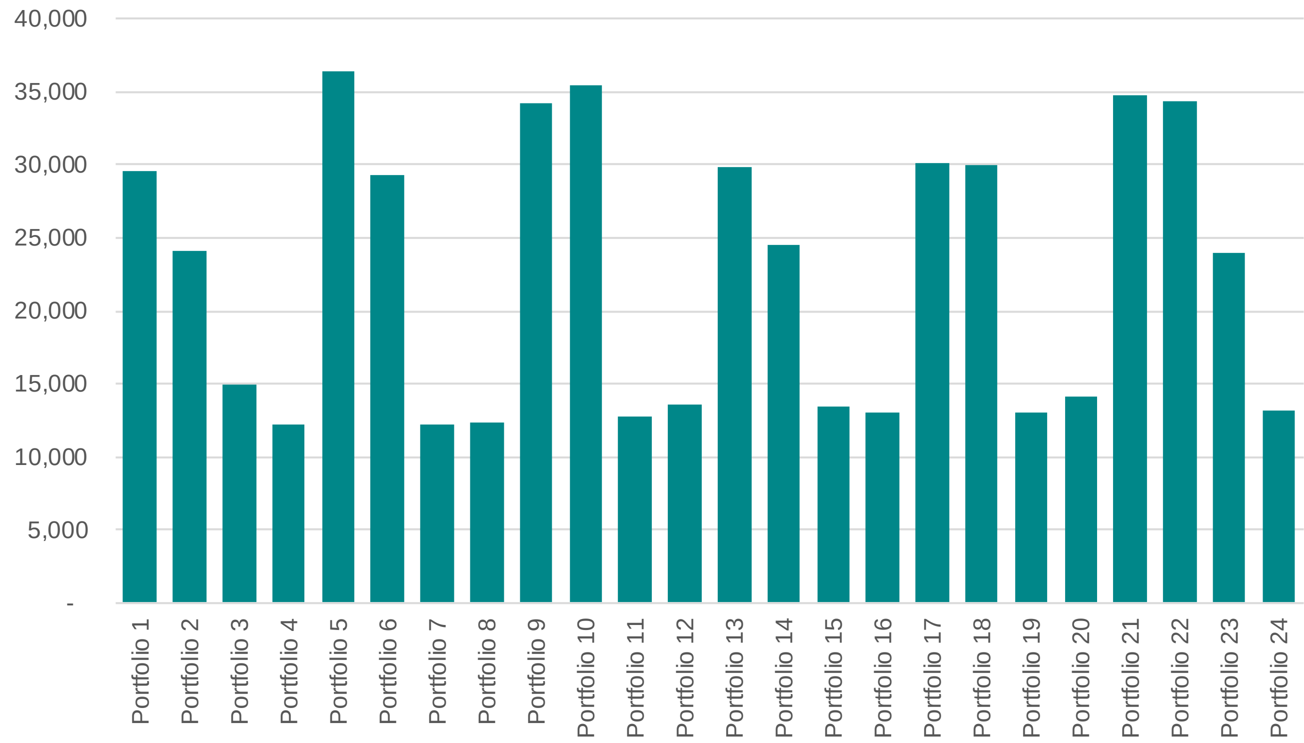


SO_2 Tons

WECC-Optimized Portfolios



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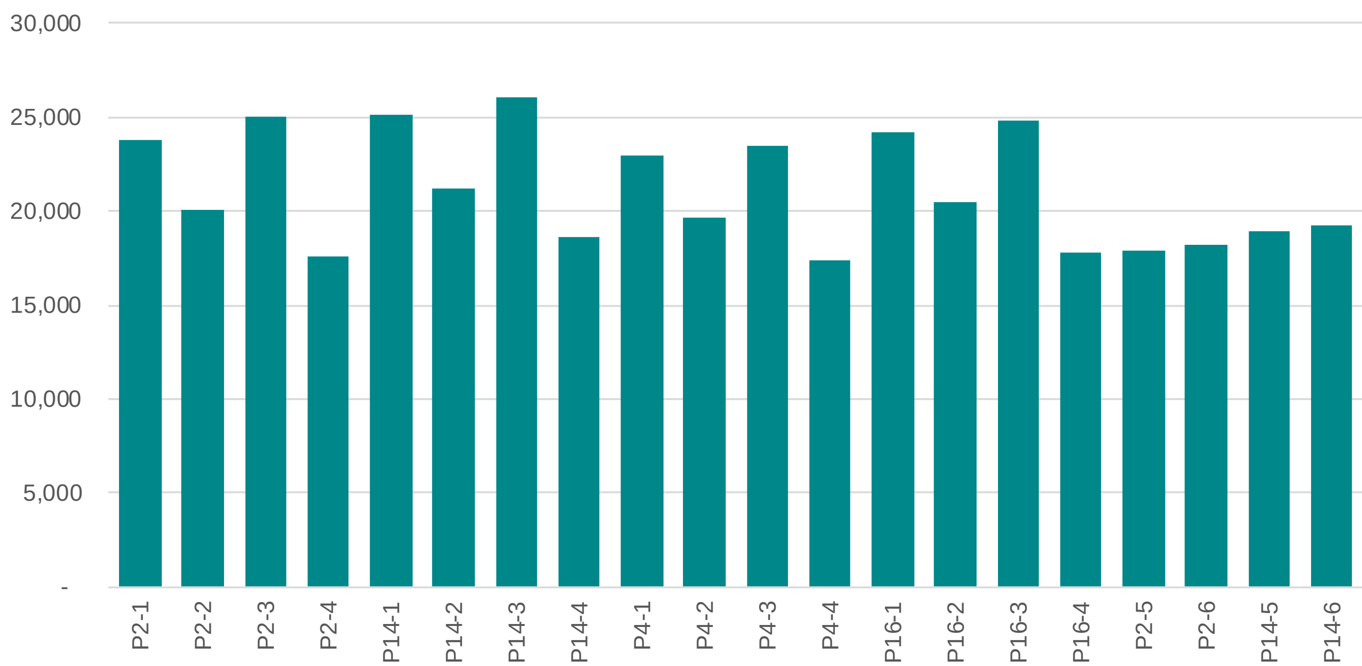

COMPLIANCE WITH STATE OF OREGON IRP GUIDELINES

Compliance with State of Oregon EV 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 poweror gas purchases, transportation, and storageand 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;* demand-side options are discussed in *Chapter 5. Demand-Side Resources*; and transmission resources are discussed in *Chapter 6. Transmission Planning*.

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 discussed in the Technical Appendix *Supply Side Resource Data – Key Financial and Forecast Assumptions*.

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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, natural gas, and water conditions) for resource portfolios are considered in *Chapter 9 Modeling Analysis*. Plant forced outages are modeled in AURORA on a unit basis and are discussed in *Chapter 9 Loss of Load Expectation*. Risk and uncertainty associated with high natural gas and high carbon cost are discussed in *Chapter 9 Portfolio Cost Analysis.*

Additional sources of risk and uncertainty including regional resource adequacy and qualitative risks are discussed in *Chapter 9. Modeling Analysis*.

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*.

The discussion of cost variability and extreme outcomes, including bad outcomes is discussed in *Chapter 9. Modeling Analysis*.

Idaho Power's Risk Management Policy regarding physical and financial hedging is discussed in *Chapter 1. IRP Methodology*. Idaho Power's Energy Risk Management Program is designed to systematically identify, quantify and manage the exposure of the company and its customers to the uncertainties related to the energy markets in which the Company is an active participant. The Company's Risk Management Standards limit term purchases to the prompt 18 months of the forward curve.

Idaho Power's plan and how the resource choices appropriately balance cost and risk is presented 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. This information is discussed in IRP Advisory Council meetings and found throughout the 2019 IRP, the 2019 Load and Sales Forecast and in the 2019 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 Friday, June 7, 2019. The company requested for comments to be provided no later than Friday, June 14, 2019.

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 2017 IRP on May 23, 2018 in Order 18-176. The Idaho Power 2019 IRP will be filed by June 30, 2019.

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 28, 2019 filing of the 2019 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:
Idaho Power submitted its annual update on January 28, 2019. A public meeting was held March 12, 2019 to discuss the 2017 IRP update.

g. Unless the utility requests acknowledgement of changes in proposed actions, the annual update is an informational filing that:
   - Describes what actions the utility has taken to implement the plan;
   - Provides an assessment of what has changed since the acknowledgment order that affects the action plan, including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource acquisitions, resource costs, and transmission availability; and
   - Justifies any deviations from the acknowledged action plan.

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 and major assumptions are discussed in *Chapter 9. Modeling Analysis*. Major assumptions are also discussed in *Chapter 7. Planning Period Forecasts.*

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 *Existing Resource 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 – Analysis of IRP ResourceResource Costs-IRP Resources* and presented in the Technical Appendix, *Supply-Side Resource Data Levelized Cost of Energy*.

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*

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 *Chapter 9. Modeling Analysis – Portfolio Emission Results* and in the Technical Appendix, *Portfolio Analysis, Results and supporting Documentation–Portfolio Emissions*.

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 2019 IRP are described in *Chapter 8. Portfolios*.

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*.

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*.

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*.

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:

Risk associated with the selected portfolio including coal-unit exits is discussed in *Chapter 10. Preferred Portfolio and Action Plan*.

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 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:

The contractor-provided conservation potential study for the 2019 IRP and is described in *Chapter 5 Demand-Side Resources – Energy Efficiency Forecasting – Potential Assessment*.

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 is provided in Cha*pter 5. Demand-Side Resources*.

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:

Idaho Power administers all its conservation programs except market transformation. Treatment of third party market transformation savings was provided by the Northwest Energy Efficiency Alliance (NEEA) and is discussed in *Appendix B: Idaho Power's Demand-Side Management 2017 Annual Report.* 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 – Changes from the 2017 IRP.*

Guideline 8: Environmental Costs

Utilities should include, in their base-case analyses, the regulatory compliance costs they expect for carbon dioxide (CO_2), nitrogen oxides, sulfur oxides, and mercury emissions. Utilities should analyze the range of potential CO_2 regulatory costs in Order No. 93-695, from zero to $40 (1990$). In addition, utilities should perform sensitivity analysis on a range of reasonably possible cost adders for nitrogen oxides, sulfur oxides, and mercury, if applicable.

Idaho Power response:

Compliance with existing environmental regulation and emissions for each portfolio are discussed in *Chapter 9. Modeling Analysis and Results—Qualitative Risk Analysis*. Emissions for each portfolio are 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 2019 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 and regulating reserves are discussed in Chapter 8. Portfolios. A loss of load expectation analysis and regional resource adequacy are discussed in *Chapter 9. Modeling Analysis.*

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:

Distributed generation technologies were evaluated in *Chapter 4. Future Supply-Side Generation and Storage Resources* and in *Chapter 7. Planning Period Forecasts—Analysis of IRP Resources*.

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 rules established by Oregon in Order No. 18-324 issued on August 30, 2018 and codified in Oregon Administrative Rules 860-089-0010-0550.

Idaho Power identifies its proposed acquisition strategy in *Chapter 10. Preferred Portfolio and Action Plan—Action Plan (2019–2026).* Discussion of asset ownership versus market purchases is found in *Chapter 9. Modeling Analysis*.

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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 2019 IRP's analysis for the flexibility guideline is provided in *Chapter 8. Portfolios.*

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 planning margin and regulating reserves is found at *Chapter 8. Portfolios.*

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 2017 IRP

Action Item 1: EIM

Continue planning for western EIM participation beginning in April 2018.

Idaho Power response:

Idaho Power joined the western EIM in April 2018.

Action Item 2: Loss-of-load and solar contribution to peak

Investigate solar PV contribution to peak and loss-of-load probability analysis.

Idaho Power response:

Solar PV contribution to peak is discussed in *Chapter 4. Future Supply-Side Generation and Storage Resources – Renewable Resource – Solar*.

Loss-of-load probability analysis is discussed in *Chapter 9. Modeling Analysis – Loss of Load Expectation.*

Action Item 3: 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.

Idaho Power response:

Idaho Power's action plan continues to target 2019 as the exit date from North Valmy Unit 1. Idaho Power's exit from Valmy Unit 1 is discuss in *Chapter 3. Idaho Power Today – Existing Supply-Side Resource – Coal Facilities* and in *Chapter 7. Planning Period Forecasts – Generation Forecast for Existing Resources – Coal Resources – North Valmy*.

The assessment of import dependability from northern Nevada is discussed in *Chapter 6. Transmission Planning – Nevada without North Valmy.*

Action Item 4: Jim Bridger Units 1 and 2

Plan and negotiate with PacifiCorp and regulators to achieve earl retirement dates of year-end 2028 for Unit 2 and year-end 2032 for Unit 1.

Idaho Power response:

Idaho Power's 2019 IRP Action Plan is detailed in Chapter 10. Action Plan (2019-2026) and includes updated target dates for early exits during 2022 and 2026. Discussion of the modeling analysis to reach these target dates is at *Chapter 7. Planning Period Forecasts – Generation Forecast for Existing Resources-Coal Resources – Jim Bridger.* Discussion of risks related to these planning and negotiating actions is discussed in *Chapter 9. Modeling Analysis – Qualitative Risk Analysis.*

Action Item 5: B2H

Conduct ongoing permitting, planning studies, and regulatory filings.

Idaho Power response:

Idaho Power continues to include B2H in the preferred portfolio and action items include permitting, negotiation and execution of partner construction agreements, preliminary construction activities, acquisition of long-lead materials, and construction of B2H. Discussion and analysis of the completed planning studies and permitting and regulatory filing is found in *Chapter 6. Transmission Planning – Boardman to Hemingway*. Modeling design and analysis testing B2H in the 2019 IRP is found in *Chapter 8. Portfolios* and *Chapter 9. Modeling Analysis*.

Action Item 6: B2H

Conduct preliminary construction activities, acquire long-lead materials, and construct the B2H project.

Idaho Power response:

Idaho Power continues to include B2H in the preferred portfolio and action items include permitting, negotiation and execution of partner construction agreements, preliminary construction activities, acquisition of long-lead materials, and construction of B2H. Discussion and analysis of the completed planning studies and permitting and regulatory filing is found in *Chapter 6. Transmission Planning – Boardman to Hemingway*. Modeling design and analysis testing B2H in the 2019 IRP is found in *Chapter 8. Portfolios* and *Chapter 9. Modeling Analysis*.

Action Item 7: 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.

Idaho Power response:

Idaho Power's action plan continues to target 2020 as the exit date from Boardman. Idaho Power's exit from Boardman is discussed in *Chapter 3. Idaho Power Today – Existing Supply-Side Resource – Coal Facilities* and in *Chapter 7. Planning Period Forecasts – Generation Forecast for Existing Resources – Coal Resources – Boardman*.

Action Item 8: Gateway West

Conduct ongoing permitting, planning studies, and regulatory filings.

Modifications: Idaho Power should provide additional information to the Commission on an ongoing basis on Energy Gateway's progress, Idaho Power's inclusion of it as a least-cost/least risk portfolio, the status of co-participants and Energy Gateway's role in the IRP.

Idaho Power response:

Discussion regarding Gateway West is found in *Chapter 6. Transmission Planning – Gateway West*.

Idaho Power files quarterly transmission updates regarding the Energy Gateway West transmission project and updates on the permitting or completion of the Boardman to Hemingway transmission line project with the OPUC in Docket RE 136. The transmission update for Q4 2018 was filed on January 15th, 2019 and the update for Q1 2019 was filed on April 30, 2019.

Action Item 9: Energy Efficiency

Continue the pursuit of cost-effective energy efficiency.

Modifications: In its 2019 IRP Idaho Power will report on future expanded energy efficiency opportunities and improvements to its avoided cost methodology.

Idaho Power response:

Idaho Power's energy efficiency opportunities and improvements to its avoided cost methodology are discussed in *Chapter 5. Demand-side Resources*.

Action Item 10: Carbon emission regulations

Continue stakeholder involvement in CAA Section 111(d) proceeding, or alternative regulations affecting carbon emissions.

Modifications: Idaho Power will provide a report as part of its 2019 IRP filing describing the risks to the company and its customers associated with climate change.

Idaho Power response:

Idaho Power continues to participate in carbon emission discussions and announced our Clean Energy Goal in March 2019. These efforts are discussed in *Chapter 2. Political, Regulatory, and Operational Issues*. Modeling of carbon regulation is discussed *in Chapter 8. Portfolios – Framework for Expansion Modeling – Carbon Price Forecasts*.

Action Item 11: North Valmy Unit 2

Plan and coordinate with NV Energy Idaho Power's exit from coal-fired operation by year-end 2025.

Idaho Power response:

Idaho Power's action plan continues to target 2025 as the exit date from North Valmy Unit 2. Idaho Power's exit from Valmy Unit 2 is discuss in *Chapter 3. Idaho Power Today – Existing Supply-Side Resource – Coal Facilities* and in *Chapter 7. Planning Period Forecasts – Generation Forecast for Existing Resources – Coal Resources – North Valmy*.

Other Item 1: 2019 IRP Preview

Idaho Power is required that five months prior to the filing of the 2019 IRP, Idaho Power file a report in this docket providing the following information:

- Comprehensive update of the B2H project.
- Information about the planned gas price forecast for the 2019 IRP, and any appropriate updates on the natural gas price forecast.
- A discussion of portfolio modeling options and preferences for the 2019 IRP.
- An update on Jim Bridger environmental control developments and options.
- Updates as requested by Staff.

Idaho Power response:

Idaho Power's filed the updated IRP Report with the OPUC on January 28, 2019.

IDAHO POWER®
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INTEGRATED RESOURCE PLAN

2019

AMENDED • JANUARY • 2020

APPENDIX D: B2H SUPPLEMENT

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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EXECUTIVE SUMMARY

The Boardman to Hemingway Transmission Line Project (B2H) is a planned 500-kilovolt (kV) transmission project that would span between the Hemingway 500-kV substation near Marsing, Idaho, and the proposed Longhorn Station near Boardman, Oregon. Once operational, B2H will provide Idaho Power increased access to reliable, low-cost market energy purchases from the Pacific Northwest. Idaho Power's planned capacity interest in B2H will increase the availability of capacity and energy from the Pacific Northwest market by 500 megawatts (MW) during the summer months, when energy demand from Idaho Power's customers is at its highest. B2H (including early versions of the project) has been a cost-effective resource identified in each of Idaho Power's integrated resource plans (IRP) since 2006 and continues to be a cornerstone of Idaho Power's 2019 IRP preferred resource portfolio. In the 2019 IRP, as has been the case in prior IRPs, the B2H project is not simply evaluated as a transmission line, but rather as a *resource* that will be used to serve Idaho Power load. That is, the B2H project, and the market purchases it will facilitate, is evaluated in the same manner as a new combined-cycle gas plant, or a new utility-scale solar complex.

As a resource, the B2H project is demonstrated to be the most cost-effective method of serving projected customer demand. As can be seen in the 2019 IRP, the lowest-cost resource portfolio includes B2H. When compared to other individual resource options, B2H is also the least-cost option in terms of both capacity cost and energy cost. As a resource alone, B2H is the lowest-cost alternative to serve Idaho Power's customers in Oregon and Idaho. As a transmission line, B2H also offers incremental ancillary benefits and additional operational flexibility.

In addition to being the least-cost, lowest-risk resource to meet Idaho Power' resource needs, the B2H project has received national recognition for the benefits it will provide. The B2H 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. Most recently, B2H was acknowledged as complementing the Trump Administration's America First Energy Plan, which addresses all forms of domestic energy production. In a November 17, 2017, United States (US) Department of the Interior press release,[1] B2H was held up as a "priority focusing on infrastructure needs that support America's energy independence…" The release went on to say, "This project will help stabilize the power grid in the Northwest, while creating jobs and carrying low-cost energy to the families and businesses who need it…" The benefits B2H is expected to bring to the region and nation have been recognized across both major political parties.

[1] blm.gov/press-release/doi-announces-approval-transmission-line-project-oregon-and-idaho

Under the B2H Permit Funding agreement, Idaho Power is allocated a 21.2-percent project interest, with PacifiCorp and Bonneville Power Administration (BPA) subscribed for the remainder of the line's capacity. The agreement will allow Idaho Power customers to benefit from the project's economies of scale and from load diversity between the project coparticipants. While Idaho Power's 21.2-percent share would provide for an annual average of 350 MW of west-to-east import capacity, the agreement is structured to provide Idaho Power with 500 MW of import capacity during the summer months, when Idaho Power experiences peak demand, and 200 MW of import capacity in the winter months, when the load-serving need is less.

The total cost estimate for the B2H project is $1 to $1.2 billion dollars, which includes Idaho Power's allowance for funds used during construction (AFUDC). Coparticipant AFUDC is not included in this estimate range. The total cost estimate includes a 20 percent contingency for unforeseen expenses. In the 2019 IRP, Idaho Power assumes a 21.2-percent share of the direct expenses, plus its entire AFUDC cost, which equates to approximately $292 million in B2H project expenses. Idaho Power also included costs for local interconnection upgrades totaling $21 million.

Idaho Power is the project manager for the permitting phase of the B2H project. The B2H project achieved a major milestone nearly 10 years in the making with the release of the Bureau of Land Management (BLM) Record of Decision (ROD) on November 17, 2017. The BLM ROD formalized the conclusion of the siting process at the federal level, as required by the *National Environmental Policy Act of 1969* (NEPA). The BLM ROD provides the ability to site the B2H project on BLM-administered land. Idaho Power also received a ROD from the U.S. Forest Service in 2018 and a ROD from the U.S. Navy in 2019.

For the State of Oregon permitting process, Idaho Power submitted the amended application for Site Certificate to the Oregon Department of Energy in summer 2017 and the Oregon Department of Energy issued a Draft Proposed Order on May 22, 2019. Oregon's Energy Facility Siting Council (EFSC) is tasked with establishing siting standards for energy facilities in Oregon and ensuring certain transmission line projects, including B2H, meet those standards.[2] Before Idaho Power can begin construction on B2H, it must obtain a Site Certificate from EFSC. The Oregon EFSC process is a standards-based process based on a fixed site boundary. For a linear facility, like a transmission line, the process requires the transmission line boundary be established (a route selected) and fully evaluated to determine if the project meets established standards. Idaho Power must demonstrate a need for the project before EFSC will issue a Site Certificate authorizing the construction of a transmission line (non-generating facility). Idaho Power's demonstration of need is based on the least-cost plan rule, for which the

[2] See generally Oregon Revised Statute (ORS) 469.300-469.563, 469.590-469.619, and 469.930-469.992.

Footnotes continued on the next page.

requirements can be met through a commission acknowledgement of the resource in the company's IRP.[3] Similar to the 2017 IRP, Idaho Power again seeks to satisfy EFSC's least-cost plan rule requirement through an acknowledgement of its 2019 IRP.

As of the date of this report, Idaho Power expects the Oregon Department of Energy (ODOE) to issue a Final Order and Site Certificate in 2021. To achieve an in-service date in the mid-2020s, preliminary construction activities must commence in parallel to EFSC permitting activities. Preliminary construction activities include, but are not limited to, geotechnical explorations, detailed ground surveys, sectional surveys, right-of-way (ROW) acquisition activities, and detailed design and construction bid package development. After the Oregon permitting process and preliminary construction activities conclude, construction activities can commence.

This B2H appendix to the 2019 IRP provides context and details that support evaluating this transmission line project as a supply-side resource, explores many of the ancillary benefits offered by the transmission line, and considers the risks and benefits of owning a transmission line connected to a market hub in contrast to direct ownership of a traditional generation resource.

[3] OAR 345-023-0020(2).

RESOURCE NEED EVALUATION

Resource Needs and Capacity Expansion Modeling

A primary goal of the IRP is to ensure Idaho Power's system has sufficient resources to reliably serve customer demand and flexible capacity needs over the 20-year planning period. The company has historically developed portfolios to eliminate resource deficiencies identified in a 20-year load and resource balance. Under this process, Idaho Power developed portfolios which were quantifiably demonstrated to eliminate the identified resource deficiencies, and qualitatively varied by resource type, where the varied resource types considered reflected the company's understanding that the financial performance of a resource class is dependent on future conditions in energy markets and energy policy.

Idaho Power received comments on the 2017 IRP encouraging the use of capacity expansion modeling for 2019 IRP portfolio development. In response to this encouragement, the company elected to use the AURORA model's capacity expansion modeling capability to develop portfolios for the 2019 IRP. Under this process, the alternative future scenarios are formulated first, and then the AURORA model is used to develop portfolios that are optimal to the selected alternative future scenarios. For example, the AURORA model can be expected under an alternative future scenario having high natural gas price and/or high cost of carbon to develop a portfolio having substantial expansion of non-carbon emitting variable energy resources, as such a portfolio is likely well fit for such a scenario.

The use of capacity expansion modeling has resulted in a departure from the practice of developing resource portfolios to specifically eliminate resource deficiencies identified by a load and resource balance. Under the capacity expansion modeling approach used for the 2019 IRP, the AURORA model selects from the variety of supply- and demand-side resource options available to it to develop portfolios that are optimal for the given alternative future scenarios with the objective of meeting a 15 percent planning margin and regulating reserve requirements associated with balancing load, wind plant output, and solar plant output. The model can also simulate retirement of existing generation units if economical as well as build resources that are economic absent a defined capacity need. The capacity expansion modeling process is discussed in further detail in Chapter 8 of Idaho Power's 2019 IRP.

In meeting the objectives for planning margin and regulating reserve requirements, the AURORA model accounts for the capability of the existing system to meet the objectives and only selects from the pool of new supply- and demand-side resource options when the existing system comes short of meeting the objectives. Existing supply-side resources include generation resources and transmission import capacity from regional wholesale electric markets, such as that provided by B2H. Existing demand-side resources include current levels of demand response and savings from current energy efficiency programs and measures.

IRP Guideline Language—Transmission Evaluated on Comparable Basis

In Order No. 07-002, the Public Utility Commission of Oregon (OPUC) adopted guidelines regarding integrated resource planning.[4]

> 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*.

Boardman to Hemingway as a Resource

The Boardman to Hemingway Transmission Line Project (B2H) is one of the most cost-effective IRP resources Idaho Power has considered as proven through successive IRPs. When evaluating and comparing alternative resources, two major cost considerations exist: 1) the capacity cost of the project (capital and other fixed costs) and 2) the energy cost of the project (variable costs). Capital costs are derived through cost estimates to install the various projects. Energy costs are calculated through a detailed modeling analysis, using the AURORA software. Energy prices are derived based on inputs into the model, such as gas price, coal price, nuclear price, hydro conditions, etc.

Illustrating the difference between capacity and energy, a diesel generator may have a very low cost to install; however, the cost of diesel fuel and the maintenance required would be significant. Alternatively, a utility-scale solar plant will have almost no energy cost; the fuel to run the plant—the sun—is free. However, in the case of a solar plant, the capacity cost to install the plant, while continuing its declining trend, can still be relatively expensive, particularly when considered in terms of cost per unit of *on-peak* capacity.

Capacity Costs

Table 1 below provides capital costs for resource options found in the 2019 IRP to have the lowest cost from a capacity perspective. Capital costs in Table 1 are provided in base year 2023 dollars. The use of 2023 as base year allows the analysis to capture declining capital cost trends for solar resources. The capital costs for B2H in the table below reflect the inclusion of local interconnection costs for B2H.

[4] apps.puc.state.or.us/orders/2007ords/07-002.pdf

Table 1. Total capital $/kW for select resources considered in the 2019 IRP (2023$)

Resource Type	Total Capital $/kW	Total Capital $/kw—peak	Depreciable Life
B2H	$894*	$626**	55 years
Combined-cycle combustion turbine (CCCT) (1x1) F Class (300 megawatts [MW])	$1,294	$1,294	30 years
Simple-cycle combustion turbine —Frame F Class (170 MW)	$1,142	$1,142	35 years
Reciprocating Gas Engine (111.1 MW)	$1,087	$1,087	40 years
Solar Photovoltaic (PV)—Utility-Scale 1-Axis	$1,498	$3,329***	30 years

* Uses the B2H 350-MW average capacity
** Uses the B2H 500-MW capacity
***Uses on-peak capacity of 45 percent of installed nameplate capacity

The B2H total capital cost per kilowatt at peak is roughly 60 percent of the cost of the next lowest-cost resource. Additionally, B2H, as a transmission line, will depreciate over 55 years compared to at most 40 years for a gas plant or 30 years for a solar plant. The low up-front cost and slower depreciation further reduces the cost impact to Idaho Power's customers. Finally, the B2H cost estimate includes a 20 percent contingency, whereas none of the other resources evaluated in the 2019 IRP includes a cost contingency. The summation of these factors suggest B2H is the lowest capital-cost resource by a substantial margin.

Energy Cost

B2H provides Idaho Power with more capacity to the Pacific Northwest to purchase power from the Mid-Columbia (Mid-C) trading hub. at both peak times and when energy prices are favorable relative to the costs of Idaho Power's existing resource fleet. Referencing Table 7.6 in the Amended IRP, the B2H project has the lowest levelized cost of energy relative to other resource options evaluated in the 2019 IRP.

Market Overview

Power Markets

A power market hub is an aggregation of transaction points (often referred to as bus points or buses). Hubs create a common point to buy and sell energy, creating one transaction point for bilateral transactions. Hubs also create price signals for geographical regions.

Six characteristics of successful electric trading markets include the following:

1. The geographic location is a natural supply/demand balancing point for a particular region with adequate available transmission.

2. Reliable contractual standards exist for the delivery and receipt of the energy.

3. There is transparent pricing at the market with no single player nor group of players with the ability to manipulate the market price.
4. Homogeneous pricing exists across the market.
5. Convenient tools are in place to execute trades and aggregate transactions.
6. Most importantly, there is a critical mass of buyers and sellers that respond to the five characteristics listed above and actively trade the market on a consistent basis. This is the definition of liquidity, which is clearly the most critical requirement of a successful trading hub.

Mid-C Market

The Mid-C electric energy market hub is a hub where power is transacted both physically and financially (derivative). Power is traded both physically and financially in different blocks: long term, monthly, balance-of-month, day ahead, and hourly. Much of the activity for balance-of-month and beyond is traded and cleared through a clearing exchange, the Intercontinental Exchange (ICE). For short-term transactions, such as day-ahead and real time (hourly), trades are made primarily between buyers and sellers negotiating price, quantity, and point of delivery over the phone (bilateral transactions). In the Pacific Northwest, most of the price negotiations begin with prices displayed for Mid-C on the ICE trading platform.

The Mid-C market exhibits all six characteristics of a successful electric trading market discussed above. Figure 1 shows the relative volume of energy in the Northwest.

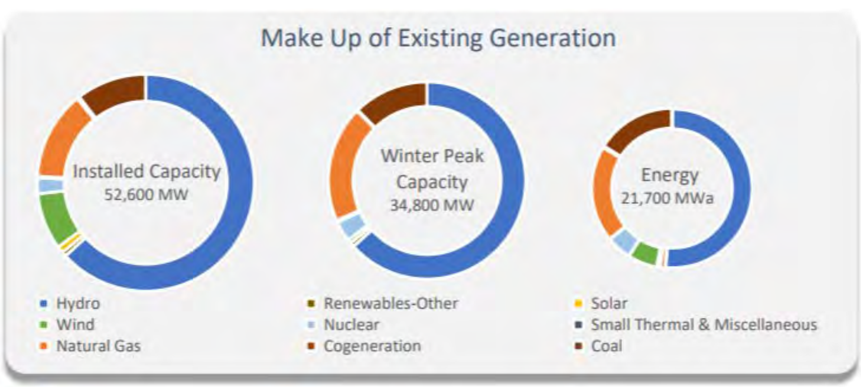

Figure 1. Northwest regional forecast (Source: 2017 PNUCC)[5]

In the western US, the other major market hubs are California–Oregon Border (COB), Four Corners (Arizona–New Mexico border), Mead (Nevada), Mona (Utah), Palo Verde (Arizona), and SP15 (California). The Mid-C market is very liquid. In 2018, on a day-ahead

[5] pnucc.org/system-planning/northwest-regional-forecast

trading basis, daily average trading volume during heavy-load hours during June and July ranged from nearly 10,000 megawatt-hours (MWh) to over 49,000 MWh. When combining heavy-load hours with light-load hours, on a day-ahead trading basis, the monthly volumes for June and July were each approximately 1,600,000 MWhs. These volumes are in addition to daily broker trades and month-ahead trading volumes. Mid-C is by far the highest volume market hub in the west; frequently, Mid-C volumes are greater than the other hubs combined.

The following market participants transact regularly at Mid-C. Additionally, numerous other independent power producers trade at Mid-C.

- Avista Utility
- BPA
- Chelan County Public Utility District (PUD)
- Douglas County PUD
- Eugene Water and Electric Board
- Idaho Power
- PacifiCorp
- Portland General Electric
- Powerex
- Puget Sound Energy
- Seattle City Light
- Tacoma Power

Energy traded at Mid-C is not necessarily physically generated in the Mid-Columbia River geographic area. For instance, Powerex is a merchant of BC Hydro in British Columbia and frequently buys and sells energy at Mid-C. A trade at Mid-C requires that transmission is available to deliver the energy to Mid-C. Transmission wheeling charges must be accounted for when transacting at Mid-C. Sellers at Mid-C must pay necessary transmission charges to deliver power to Mid-C, and buyers must pay necessary transmission charges to deliver power to load.

Mid-C and Idaho Power

Historically, Idaho Power wholesale energy transactions have correlated well with the Mid-C hub due to Idaho Power's proximity to the market hub and because it is the most liquid hub in the region. Energy at Mid-C can be delivered to, or received from, Idaho Power through a single transmission wheel through the BPA or Avista. Additionally, long-term monthly price quotes are readily available for Mid-C, making it an ideal basis for long-term planning.

Idaho Power uses the market to balance surplus and deficit positions between generation resources and customer demand, and to take advantage of price differences across the region. For example, when market purchases are more cost-effective than generating energy within Idaho Power's generation fleet, Idaho Power customers benefit from lower net power supply cost through purchases instead of Idaho Power fuel expense. Idaho Power customers also benefit from the sale of surplus energy. Surplus energy sales are made when Idaho Power's resources are greater than Idaho Power customer demand and when the incremental cost of these resources are below market prices. Idaho Power customers benefit from these surplus energy sales as offsets to net power supply costs through the power cost adjustment (PCA).

In 2018, Idaho Power averaged approximately 85,000 MWh of total Mid-C purchases in June and July. As stated previously, the average monthly volumes at Mid-C, on a day-ahead basis, were approximately 1,600,000 MWh. Based on these averages, Idaho Power's purchases represented about 5 percent of the total market volumes in June and July. At 5 percent of total market volume on average in June and July, Idaho Power represents a very small fraction of the Mid-C volume during the months when Idaho Power relies on Mid-C the most.

The Mid-C market could be used more to economically serve Idaho Power customers, but Idaho Power's ability to transact at Mid-C is limited due to transmission capacity constraints between the Pacific Northwest and Idaho. In other words, sufficient transmission capacity is currently unavailable during certain times of the year for Idaho Power to procure cost-effective resources from Mid-C for its customers, even though generation supply is available at the market.

Modeling of the Mid-C Market in the IRP

As part of the IRP analysis, Idaho Power uses the AURORA model to derive energy prices at the Mid-C market. Energy prices are derived based on inputs into the model, such as gas price, coal price, nuclear fuel price, hydro conditions, etc. Refer to chapters 8 and 9 of the 2019 IRP for more information on AURORA and modeling.

Energy purchases from the market require transmission to wheel the energy from the source to the utility purchasing the energy. Purchases from the Mid-C market would need to be wheeled across the BPA system to get the energy to the proposed Longhorn Substation near Boardman, Oregon.

Transmission wheeling rates and wheeling losses are included in the AURORA database and are part of the dispatch logic within the AURORA modeling. AURORA economically dispatches generating units, which can be located across any system in the West. All market energy purchases modeled in AURORA include these additional transmission costs and are included in all portfolios and sensitivities.

B2H Comparison to Other Resources

The 2019 IRP provides an in-depth analysis of the B2H project compared to alternative resource options. Table 2 summarizes some of the high-level differences between B2H and other notable resource options.

Table 2. High-level differences between resource options

	B2H	Reciprocating engines	CCCT	Lithium batteries	1-axis solar PV
Intermittent renewable					✓
Dispatchable capacity providing	✓	✓	✓	✓	
Non-dispatchable (coincidental) capacity providing					✓
Balancing, flexibility providing	✓	✓	✓	✓	
Energy providing	✓	✓	✓	✓	✓
Variable costs (primary variable cost driver)	Mid-C market	Natural gas	Natural gas	Mid-C market	No variable costs
Capital costs	$626 per on-peak kW	$1,087-1,205 per kW/kW	$1,294/kW	$1,870-3,004 per kW	$3,329 per /on-peak kW
Fuel price risk		✓	✓		
Wholesale power market price risk	✓			✓	
Other	Expanded access to market (Mid-C) providing abundant clean, renewable energy, highly reliable (low forced outage), as long-lived resource promotes stability in customer rates, benefit to regional grid, supports Idaho Power's clean energy goal, long-lead resource.	Scalable (modeled generators 18.8-MW nameplate), relatively short-lead resource, range driven by plant configuration.	Relatively short-lead resource, dispatchable, recent construction experience.	Uncertainty related to performance (e.g., # of lifetime cycles), dispatchable, scalable, potential for geographic dispersion, cost range driven by storage duration.	Renewable, clean, scalable (modeled plants 40-MW nameplate), diminishing on-peak contribution with expanded penetration, short-lead resource, intermittent.

Notes:

1. Provided capital costs are in nominal dollars assuming 2023 on-line date (i.e., 2023$).
2. Solar is not dispatchable but tends to produce at fairly high levels during summer periods of high customer demand. For the expressed capital cost per on-peak kW, the assumed on-peak capacity is 45 percent of installed capacity.
3. Lithium battery is a net energy consumer (roundtrip efficiency = 88 percent). Lithium battery provides energy during heavy load hours or other high energy demand/high energy value periods; battery recharge costs tied primarily to Mid-C market costs or variable costs of Idaho Power's system resources during light load hours.
4. B2H capital-cost estimate includes a 20-percent contingency. No other resources include contingency. B2H and solar capital costs are expressed in terms of $/on-peak kW, where on-peak kW for B2H are based on 500-MW summer capacity and for solar is based on on-peak capacity equal to 45 percent of installed capacity.

Idaho Power's Transmission System

Idaho Power's transmission system is a key element to providing reliable, responsible, fair-priced energy services. A map of Idaho Power's transmission system is shown in Figure 6.1

of the 2019 IRP and in Figure 2. Transmission lines facilitate the delivery of economic resources and allow resources to be sited where most cost effective. In most instances, the most economic/best location for resources is not immediately next to major load centers (i.e., hydro along the Columbia River, wind in Wyoming, solar in the desert southwest). For much of its history, Idaho Power has taken advantage of resources outside of its major load pockets to economically serve its customers. The existing transmission lines between Idaho Power and the Pacific Northwest have been particularly valuable. Idaho Power fully utilizes the capacity of these lines. Additional transmission capacity is required to access resources to serve incremental increases in peak demand. The B2H project is the mechanism to increase capacity between the Pacific Northwest and Idaho Power's service area.

Transmission lines are constructed and operated at different operating voltages depending on purpose, location, and distance. Idaho Power operates transmission lines at 138 kV, 161 kV, 230 kV, 345 kV, and 500 kV. Idaho Power also operates sub-transmission lines at 46 kV and 69 kV, but these voltages will not be discussed further in this appendix; the focus of this appendix is on higher voltage transmission lines used for moving bulk electricity. The higher the voltage, the greater the capacity of the line, but also greater construction cost and physical size requirements.

The utility industry often compares transmission lines to roads and highways. Typically, lower-voltage transmission lines (138 kV) are used to facilitate delivery of energy to substations to serve load, like a two-lane highway, while high-voltage transmission lines are used for bulk transfer of energy from one region to another, like an interstate highway. Much like roads and highways, transmission lines can become congested. Depending on the capacity needs, economics, distance (higher voltages result in less losses over long distances), and intermediate substation requirements, either 230-kV, 345-kV, or 500-kV transmission lines are chosen.

Transmission Capacity Between Idaho Power and the Pacific Northwest

A transmission path is one or more transmission lines that collectively transmit power to/from one geographic area to another. Idaho Power owns 1,280 MW of transmission capacity between the Pacific Northwest transmission system and Idaho Power's transmission system. Of this capacity, 1,200 MW are on the Idaho to Northwest path (Western Electricity Coordinating Council [WECC] Path 14), and 80 MW are on the Montana–Idaho path (WECC Path 18). The Idaho to Northwest transmission path is comprised of three 230-kV lines, one 500-kV line, and one 115-kV line. The capacity limit on the path is established through a WECC rating process based on equipment overload ratings resulting from the loss of the most critical element on the transmission system. Collectively, these lines between Idaho and the Northwest have a transfer capacity rating that is greater than the individual rating of each line but less than the sum of the individual capacity ratings of each line. Figure 2 shows an overview of Idaho Power's high-voltage transmission system.

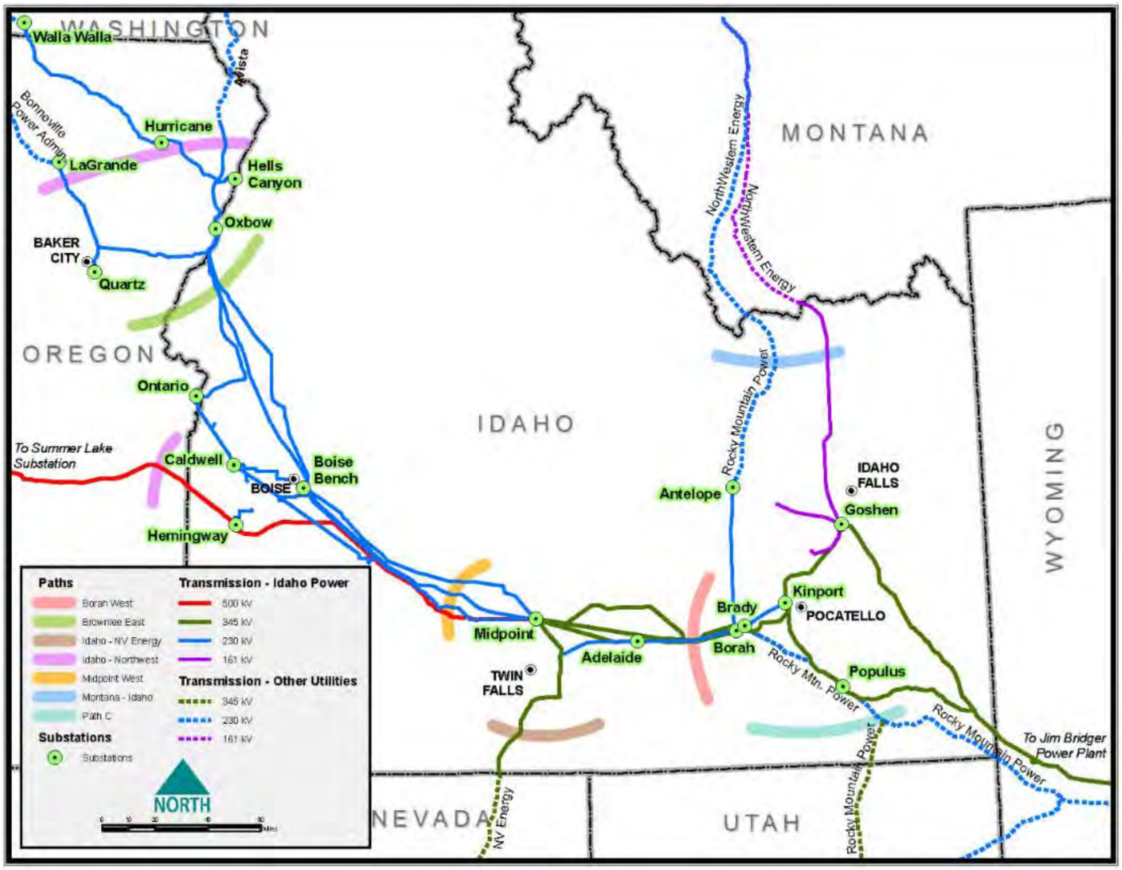

Figure 2. Idaho Power transmission system map

Table 3 details the capacity allocation between the Pacific Northwest and Idaho Power in 2019. The shaded rows represent capacity amounts that can be used to serve Idaho Power's native load. Although Idaho Power owns 1,280 MW of transmission capacity between the Pacific Northwest and Idaho Power's system, after all other uses are accounted for, Idaho Power will only able to use 304 MW to serve Idaho Power's native load in 2019. Idaho Power used 366 MW to serve BPA or PacifiCorp network load on Idaho Power's system, 280 MW were allocated to Transmission Reserve Margin (TRM), and 330 MW were allocated to Capacity Benefit Margin (CBM).

Table 3. Pacific Northwest to Idaho Power import transmission capacity

Firm Transmission Usage (Pacific Northwest to Idaho Power)	Capacity (July MW)
BPA Load Service (Network Customer)	365
Boardman Generation	60
Fighting Creek (PURPA)	4
Pallette Load (PacifiCorp—Network Customer)	1
TRM	280
CBM	330
Subtotal	**1,040**
Pacific Northwest Purchase (Idaho Power Load Service)	240
Total	**1,280**

TRM is transmission capacity that Idaho Power sets aside as unavailable for firm use, for the purposes of grid reliability to ensure a safe and reliable transmission system. Idaho Power's TRM methodology, approved by the Federal Energy Regulatory Commission (FERC) in 2002, requires Idaho Power to set aside transmission capacity based on the average loopflow on the Idaho to Northwest path. In the west, electrical power is scheduled through a contract-path methodology, which means if 100 MW is purchased and scheduled over a path, that 100 MW is decremented from the path's total availability. However, physics dictate the actual power flow over the path (based on the path of least resistance), so actual flows don't equal contract-path schedules. The difference between scheduled and actual flow is referred to as unscheduled flow or loopflow. The average adverse loopflow across the Idaho to Northwest path during the month of July is 280 MW.

CBM is transmission capacity Idaho Power sets aside, as unavailable for firm use, for the purposes of accessing reserve energy to recover from severe unplanned generation outages. Reserve generation capacity is critical and CBM allows a utility to reduce the amount of reserve generation capacity on its system by providing transmission availability to another market, such as the Pacific Northwest, which is rich with surplus capacity necessary for emergency conditions.

Montana–Idaho Path Utilization

To utilize Idaho Power's share of the Montana–Idaho 80 MW of capacity, Idaho Power must purchase transmission service from either Avista or BPA. This transmission system connects the purchased resource in the Pacific Northwest to Idaho Power's transmission system. Avista or BPA transmits, or wheels, the power across their transmission system and delivers the power to Idaho Power's transmission system. The Montana–Idaho path is identified in Figure 2 above.

Idaho to Northwest Path Utilization

To utilize Idaho Power's share of the Idaho to Northwest capacity, Idaho Power must purchase transmission service from Avista, BPA, or PacifiCorp. Table 4 details a typical summer allocation of the Idaho to Northwest capacity:

Table 4. The Idaho to Northwest Path (WECC Path 14) summer allocation

Transmission Provider	Idaho to Northwest Allocation (Summer West to East) (MW)
Avista (to Idaho Power)	340
BPA (to Idaho Power)	350
PacifiCorp (to Idaho Power)	510
Total Capability to Idaho Power	**1,200***

* During times of very low generation at Brownlee, Oxbow, and Hells Canyon hydro plants, the Idaho to Northwest path total capability can increase to as much as 1,340 MW; low generation at these power plants does not correspond with Idaho Power's system peak.

Avista, BPA and PacifiCorp share an allocation of capacity on the western side of the Idaho to Northwest path, and Idaho Power owns 100 percent of the capacity on the eastern side of the Idaho to Northwest path. For Idaho Power to transact across the path and serve customer load, Idaho Power's Load Servicing Operations must purchase transmission service from Avista, BPA, or PacifiCorp to connect the selling entity, via a contract transmission path, to Idaho Power.

Construction of B2H will add 1,050 MW of capacity to the Idaho to Northwest path in the west-to-east direction, of which Idaho Power will own 500 MW in the summer months (April–September), and 200 MW in the winter months (January–March and October–December). A total breakdown of capacity rights of the B2H permitting coparticipants can be found in the Project Coparticipants section of this report. The Idaho to Northwest path is identified in Figure 2 above.

Regional Planning—Studies and Conclusions

The Northern Tier Transmission Group (NTTG) is a regional planning organization that is organized and operates in compliance with FERC orders 890 and 1000. The purpose of NTTG is to consolidate each member's local transmission plans and determine a regional plan that can meet the needs of the combined member footprint in a more efficient or cost-effective manner. Idaho Power is a member of and participates in the NTTG.

At NTTG, all member utilities submit their load forecasts, generation forecasts, and transmission needs. NTTG studies the members' transmission footprints to determine the more efficient or cost-effective plan to meet those needs.

B2H has been, and remains, an integral part of NTTG's 10-year plan. NTTG's analysis indicated B2H is the most cost-effective and efficient project to meet the needs of the NTTG footprint.

The study noted that "Boardman to Hemingway resolved performance issues between the Northwest and Idaho under summer import conditions."[6]

In the 2018–2019 planning cycle, B2H was selected into the NTTG's Regional Transmission Plan. For the most recent updates related to Idaho Power's regional planning organization, refer to the NTTG website at nttg.biz/.

The northwest has historically been represented by two regional planning organizations, NTTG and Columbia Grid. Idaho Power is participating in an effort to combine NTTG and Columbia Grid in to a single entity known as NorthernGrid. NorthernGrid will improve regional planning by including all Northwest utilities into a common regional planning organization. The formation of NorthernGrid is expected to be completed in early 2020.

[6] NTTG 2018–2019 Regional Transmission Plan. nttg.biz

The B2H Project

Project History

The B2H project originated from Idaho Power's 2006 IRP. The 2006 IRP specified 285 MW of additional transmission capacity, increasing Idaho Power's connection to the Pacific Northwest power markets, as a resource in the preferred resource portfolio. A project had not been fully vetted at that time but was described as a 230-kV transmission line between McNary Substation and Boise. After the initial identification in the 2006 IRP, Idaho Power evaluated numerous capacity upgrade alternatives. Considering distance, cost, capacity, losses, and substation termination operating voltages, Idaho Power determined a new 500-kV transmission line between the Boardman, Oregon, area and the proposed Hemingway 500-kV substation would be the most cost-effective method of increasing capacity. Refer to Appendix D-1 for more information on the upgrade options considered.

Transmission capacity, especially at 500 kV, can be described as "lumpy" because capacity increments are relatively large between the different transmission operating voltages. In the 2009 IRP, Idaho Power assumed 425 MW of capacity, which was 50 percent of the assumed total rating. Idaho Power's long-standing preference was to find a partner or partners to construct B2H with to take advantage of economies of scale. In the 2011 IRP, Idaho Power assumed 450 MW of capacity. In 2012, Idaho Power achieved two major milestones: 1) PacifiCorp and BPA officially joined the B2H project as permitting coparticipants and 2) Idaho Power received a formal capacity rating for the B2H project via the WECC Path Rating Process (more on this process in preceding section). In the 2013 IRP, Idaho Power began to use the negotiated capacity from the permitting agreement: 500 MW in the summer and 200 MW in the winter, a yearly average of 350 MW, for a cost allocation of 21 percent of the total project. Idaho Power used the same 21.2 percent interest in the 2015, 2017 and 2019 IRPs.

Public Participation

The B2H project development has involved considerable stakeholder interaction over the last 12 years. Idaho Power has hosted and participated in over 275 public and stakeholder meetings with an estimated 4,500+ participants. After approximately a year of public scoping in 2008, Idaho Power paused the federal and state review process and initiated a year-long comprehensive public process to gather more input. This community advisory process (CAP) took place in 2009 and 2010. The four objectives and steps of the CAP were as follows:

1. Identify community issues and concerns.

2. Develop a range of possible routes that address community issues and concerns.

3. Recommend proposed and alternate routes.

4. Follow through with communities during the federal and state review processes.

Through the CAP, Idaho Power hosted 27 Project Advisory Team meetings, 15 public meetings, and 7 special topic meetings. In all, nearly 1,000 people were involved in the CAP, either through Project Advisory Team activities or public meetings. Additionally, numerous meetings with individuals and advocacy groups were held during and after the process.

Ultimately, the route recommendation from the CAP was the route Idaho Power brought into the *National Environmental Policy Act of 1969* (NEPA) process as the proponent-recommended route. The NEPA process included additional opportunities for public comment at major milestones, and Idaho Power worked with landowners and communities along the way. Ultimately, the route selected through the NEPA process was based on the Bureau of Land Management's (BLM) analysis and public input. For more information on the CAP, including the final report[7], and Idaho Power's initial scoping activities, visit the documents section[8] on the B2H website.

Throughout the BLM's NEPA process, including development of the Draft Environmental Impact Statement (EIS), issued Dec. 19, 2014, and prior to the Final EIS, issued Nov. 22, 2016, Idaho Power worked with landowners, stakeholders and jurisdictional leaders on route refinements and to balance environmental impacts with impacts to farmers and ranchers. For example, Idaho Power met with the original "Stop Idaho Power" group in Malheur County to help the group effectively comment and seek change from the BLM when the Draft EIS indicated a preference for a route across Stop Idaho Power stakeholder lands. BLM's decision was modified, and the route moved away from an area of highly valued agricultural lands in the Final EIS almost two years later.

Idaho Power worked with landowners in the Baker Valley, near the National Historic Oregon Trail Interpretive Center (NHOTIC), to move an alternative route along fence lines to minimize impacts to irrigated farmland, where practicable. This change was submitted by the landowners and included in the BLM's Final EIS and ROD (issued Nov. 17, 2017). Another change in Baker County was in the Burnt River Canyon and Durkee area, where Idaho Power worked with the BLM and affected landowners to find a more suitable route than what was initially preferred in the Draft EIS. Idaho Power is still working with landowners and local jurisdictional leaders to microsite in these areas to minimize impacts.

Unfortunately, the route preferences of Idaho Power and the local communities aren't always reflected in the BLM's Agency Preferred route. For example, Idaho Power had worked in the Baker County area to propose a route on the backside of the NHOTIC (to the east) to minimize

[7] boardmantohemingway.com/documents/CAP%20Report-Final-Feb%202011.pdf

[8] boardmantohemingway.com/documents.aspx

visual impacts, and in the Brogan area, to avoid landowner impacts. However, both route variations went through priority sage grouse habitat and were not adopted in BLM's Agency Preferred route.

However, Idaho Power worked with Umatilla County, local jurisdictional leaders and landowners to identify a new route through the entire county, essentially moving the line further south and away from residences, ranches, and certain agriculture. This southern route variation through Umatilla County was included the BLM's Agency Preferred route.

At the urging of local landowners along Bombing Range Road in Morrow County, Idaho Power has been working with local jurisdictional leaders, delegate representatives, farmers, ranchers, and other interested parties to gain the Navy's consideration of an easement along the eastern edge of the Boardman Bombing Range. This cooperative effort with the local area has benefited the Project, providing an approach that meets the interests and common good for all the noted parties in the local area. A major milestone was achieved when the U.S. Navy issued a Record of Decision for the proposed route in September 2019.

Finally, in Union County Idaho Power worked with local jurisdictional leaders, stakeholder groups, such as the Glass Hill Coalition and some members of StopB2H (prior to that group's formation) to identify new route opportunities. The Union County B2H Advisory Commission agreed to submit a route proposal to the BLM that followed existing high-voltage transmission lines, which was later identified as the Mill Creek Alternative. At the same time, Idaho Power met with a large landowner to adjust the Morgan Lake Alternative route to minimize impacts. Idaho Power understood that both the Mill Creek and Morgan Lake route variations were favored over BLM's Agency Preferred Alternative (referred to as the Glass Hill Alternative) by local landowners, the Glass Hill Coalition, several stakeholders, and the Confederated Tribe of the Umatilla Indian Reservation due to concerns of impacts on areas that had no prior development. Idaho Power continued support of the community-favored routes in its Application for Site Certificate filed with the Oregon Department of Energy in September 2018. Idaho Power will work with Union County and local stakeholders to determine the route preference between the Morgan Lake and Mill Creek alternatives.

Project Activities

Below is a summary of notable activities by year since project inception. For more information about any of the activities, please visit the B2H website.

2006

Idaho Power files its IRP with a transmission line to the Pacific Northwest identified in the preferred resource portfolio.

2007

Idaho Power analyzes the capacity and cost of different transmission line operating voltages and determines a new 500-kV transmission line to be the most cost-effective option to increase capacity and meet customer needs. Idaho Power files a Preliminary Draft Application for Transportation and Utility Systems and Facilities on Federal Lands. Idaho Power scopes routes.

2008

Idaho Power submits application materials to the BLM. Idaho Power submits a Notice of Intent to the EFSC. The BLM issues a Notice of Intent to prepare an EIS; officially initiating the BLM-led federal NEPA process. Idaho Power embarks on a more extensive public outreach program to determine the transmission line route.

2009

Idaho Power pauses NEPA and EFSC activities to work with community members throughout the route as part of the CAP to identify a proposed route that would be acceptable to both Idaho Power and the public. Forty-nine routes and/or route segments were considered through CAP.

2010

The CAP concludes. Idaho Power resubmits a proposed route to the BLM based on input from the CAP. The BLM re-initiates the NEPA scoping process and solicits public comments. Idaho Power publishes its B2H Siting Study. Idaho Power files a Notice of Intent with EFSC.

2011

Additional public outreach resulted in additional route alternatives submitted to the BLM. The Obama Administration recognizes B2H as one of seven national priority projects[9].

2012

The ODOE conducts informational meetings and solicits comments. The ODOE issues a Project Order outlining the issues and regulations Idaho Power must address in its Application for Site Certificate. Additional public outreach and analysis resulted in route modifications and refinements submitted to the BLM. Idaho Power issues a Siting Study Supplement. Idaho Power conducts field surveys for the EFSC application. WECC adopts a new Adjacent Transmission Circuits definition with a separation distance of 250 feet, which would later modify routes in the EIS process. Idaho Power receives a formal capacity rating from WECC.

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

2013

Public meetings are held. Idaho Power submits its Preliminary Application for Site Certificate to the ODOE. The BLM releases preliminary preferred route alternatives and works on a Draft EIS.

2014

The BLM issues a Draft EIS identifying an Agency Preferred Alternative. The 90-day comment period opens. Idaho Power conducts field surveys for EFSC application.

2015

The BLM hosts open houses for the public to learn about the Draft EIS, route alternatives, environmental analysis. The BLM reviews public comments. Idaho Power notifies the BLM of a preferred termination location, Longhorn Substation. Idaho Power submits an application to the Navy for an easement on the Naval Weapons System Training Facility in Boardman.
Idaho Power conducts field surveys for the EFSC application.

2016

Idaho Power submits a Draft Amended Application for Site Certificate to the ODOE for review. The BLM issues a Final EIS identifying an environmentally preferred route alternative and an Agency Preferred route alternative. Idaho Power incorporates the Agency Preferred route alternative into the EFSC application material. Idaho Power collaborates with local area stakeholders in Morrow County to find a routing solution on Navy-owned land. Idaho Power submits a revised application to the Navy. Idaho Power conducts field surveys for the EFSC application.

2017

Idaho Power submits an Amended Application for Site Certificate to the ODOE. The BLM issues a Record of Decision.

2018

ODOE and Idaho Power conduct public meetings after ODOE determined the Application for Site Certificate was complete. The Oregon PUC issues Order No. 18-176 in Docket No. LC 68 specifically acknowledging Idaho Power’s 2017 Integrated Resource Plan and action items related to B2H. The U.S. Forest Service issues a Record of Decision. Idaho Power prepares and submits a Geotechnical Plan of Development to the BLM for approval.

2019

The U.S. Forest Service issues ROW easement. ODOE issues a Draft Proposed Order. The U.S. Navy issues a Record of Decision. BPA issues a ROD for moving the existing 69-kV line from

Navy property to accommodate the B2H project. Idaho Power coordinates with BLM on Geotechnical Plan of Development. Preparations begin for issuing detailed design bid package.

For a detailed list of project activities by year, please refer to Appendix D-2.

Route History

As stated previously, the B2H project was first identified in the 2006 IRP. At that time, the transmission line was contemplated as a line between Boise and McNary. The project evolved into a 500-kV line between the Boardman area and the Hemingway Substation. Several northern terminus substations were considered over the years, including the Boardman coal plant 500-kV yard, the proposed Grassland Substation to be constructed by Portland General Electric to integrate the then-proposed Carty Plant, and the proposed Longhorn Substation, which at the time was proposed by BPA to integrate wind onto the BPA 500-kV transmission system. During scoping, a considerable number of routes were considered to connect Hemingway and the Boardman area. Figure 3 is a snapshot of a number of routes considered early on during the CAP process (2009 timeframe). Numerous alternatives were considered, including routes through Idaho and through central Oregon. This large number of routes was further refined during the CAP process.

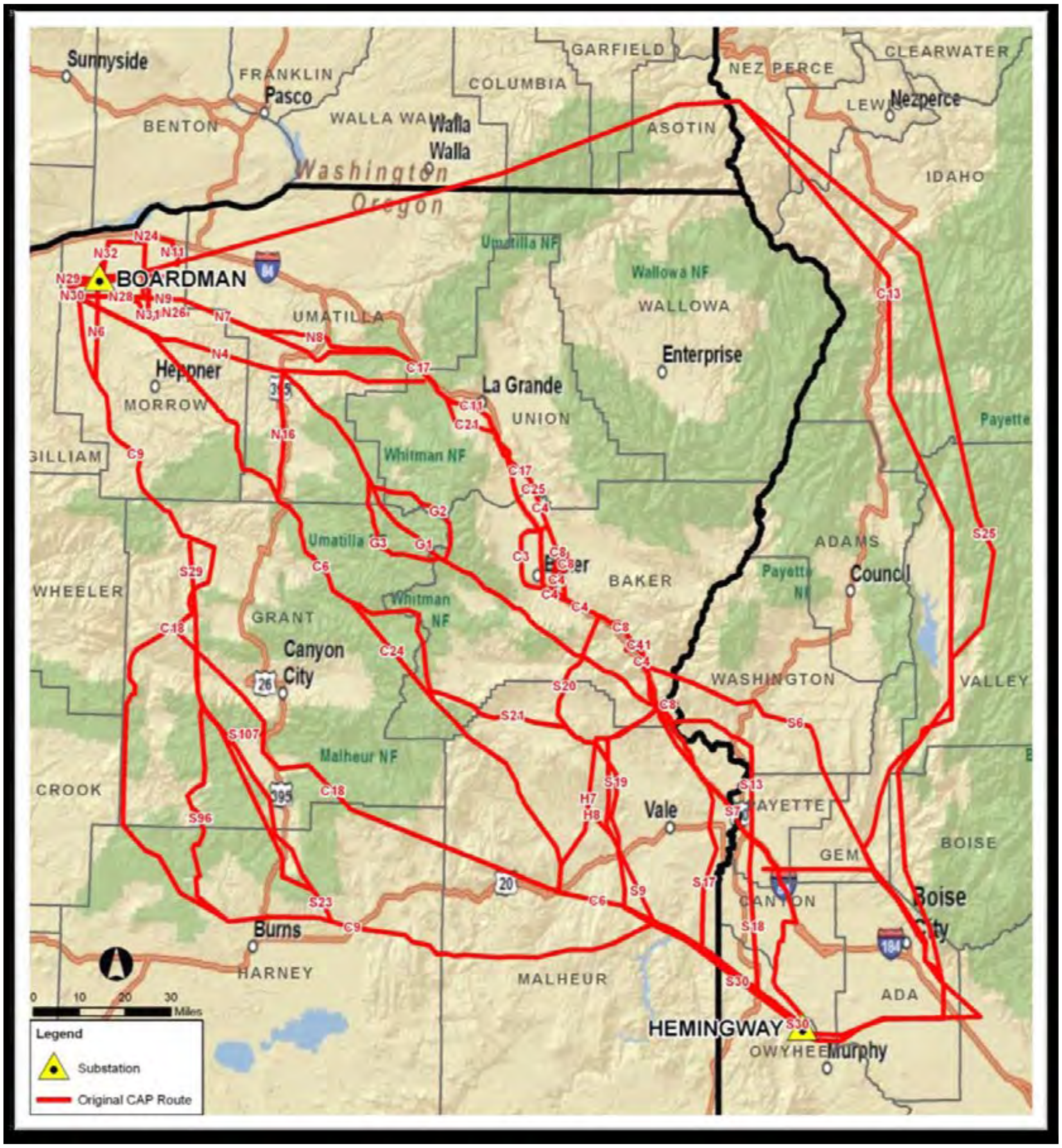

Figure 3. Routes developed by the Community Advisory Process teams (2009 timeframe)

The CAP process resulted in Idaho Power submitting the route shown in Figure 4 as the company's proposed route in the BLM-led NEPA process.

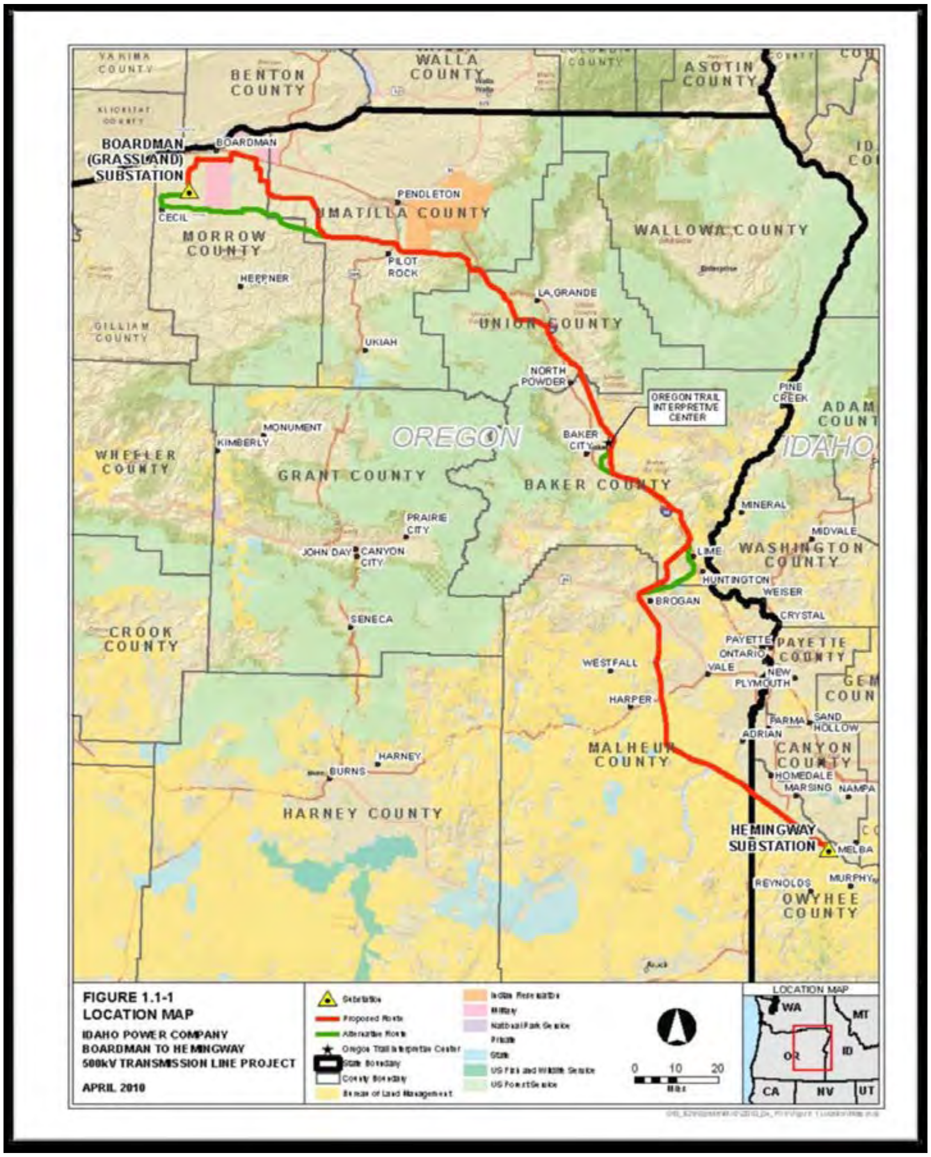

Figure 4. B2H proposed route resulting from the Community Advisory Process (2010 timeframe)

The BLM considered Idaho Power's proposed route, along with a number of other reasonable alternative routes, in the NEPA process. Figure 5 shows the route alternatives and variations considered in the BLM's November 2016 Final EIS.

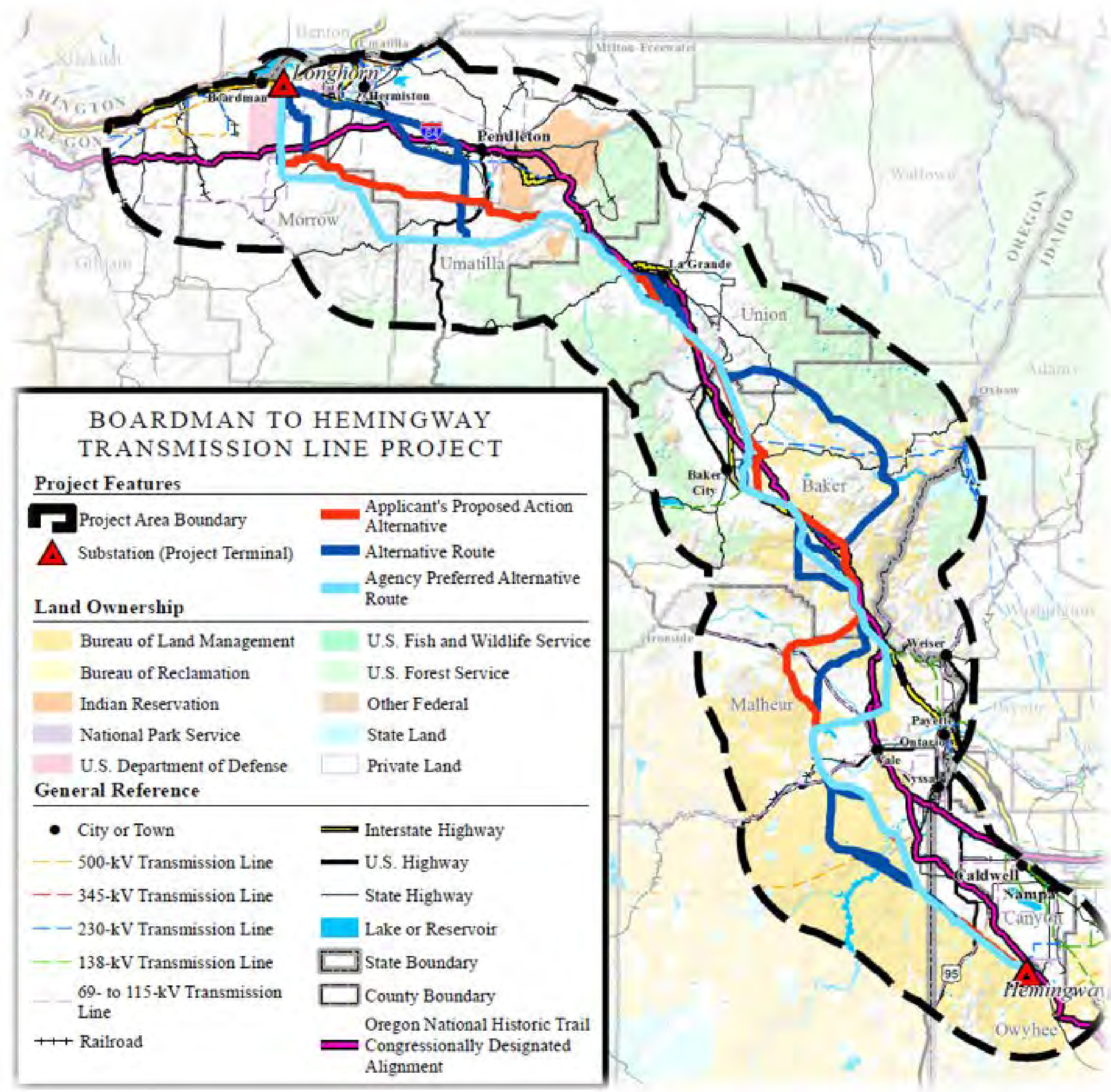

Figure 5. BLM final EIS routes

The conclusion of the BLM-led NEPA process, the BLM's ROD, resulted in a singular route—the BLM's Agency Preferred route. The 293.4-mile approved route will run across 100.3 miles of federal land (managed by the BLM, the U.S. Forest Service [USFS], the Bureau of Reclamation, and the U.S. Department of Defense), 190.2 miles of private land, and 2.9 miles of state lands. Figure 6 shows the BLM's Agency Preferred route.

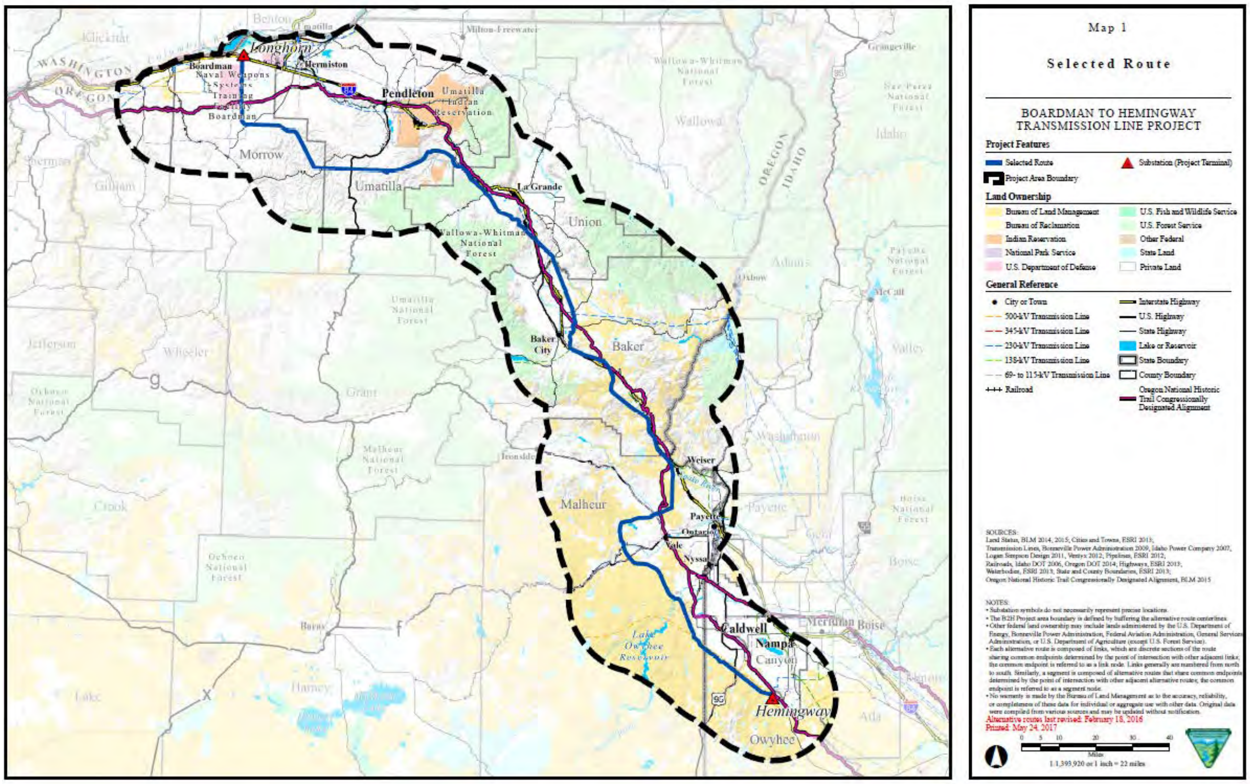

Figure 6. BLM Agency Preferred route from the 2017 BLM ROD

As discussed previously, the BLM-led NEPA process and the EFSC process are separate and distinct processes. Idaho Power submitted its Amended Application for Site Certificate to the ODOE in summer 2017. The route Idaho Power submitted to the ODOE as part of the Application for Site Certificate is very similar to the BLM's Agency Preferred route, except for a small section of private property west of La Grande. The BLM's Agency Preferred route in this area was a surprise to Idaho Power and seemingly all stakeholders in the area. The section the BLM chose was not the county's stated preference, nor was it the variation Idaho Power had worked with a large local landowner to modify to minimize impacts to his property.

At the time of EFSC application finalization (which was prior to the Final EIS release), Idaho Power did not feel as if there was a stakeholder consensus preference between the county's preferred route and the modified route west of the City of La Grande. Therefore, Idaho Power brought both alternatives into the EFSC application. Idaho Power continues to work with the community to finalize which of the two variations in this area will be constructed. Figure 7 shows the route Idaho Power submitted in its 2017 EFSC Application for Site Certificate.

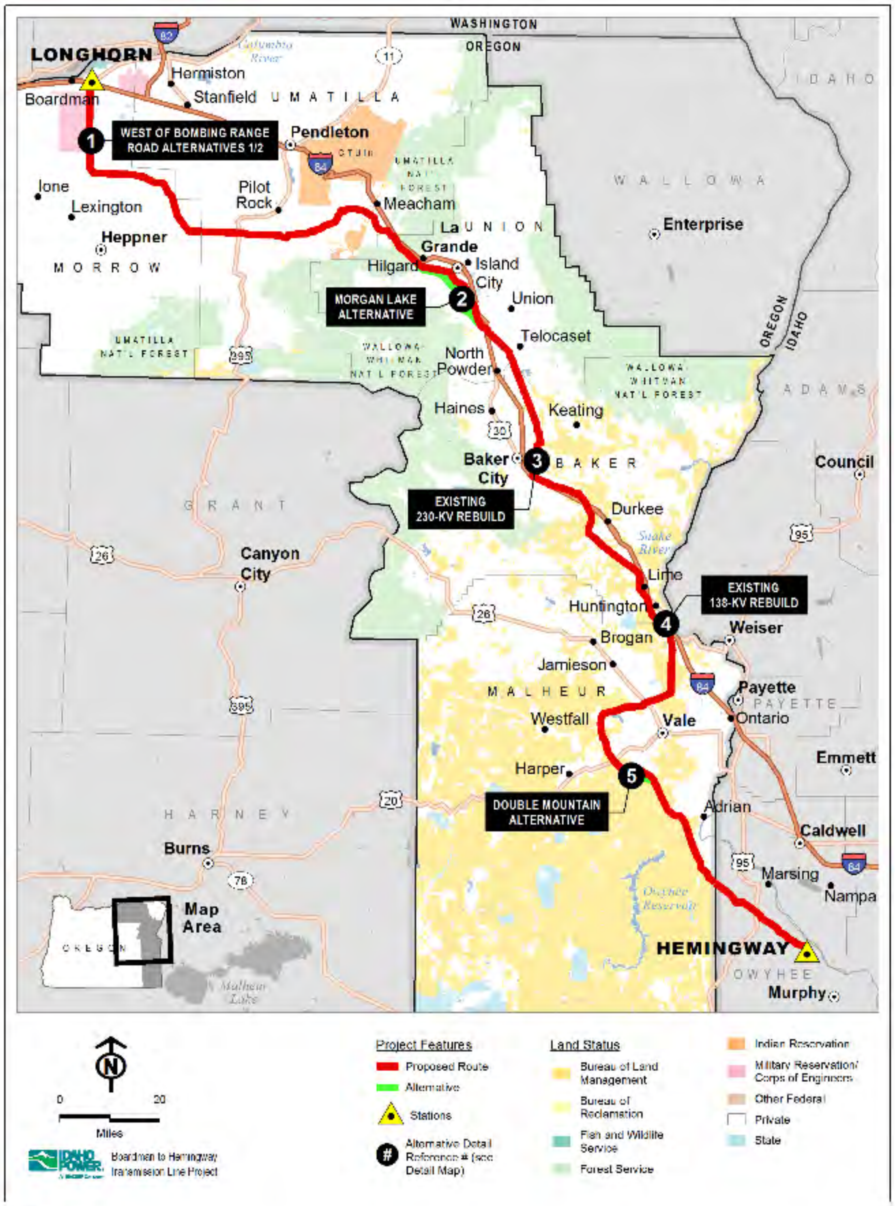

Figure 7. B2H route submitted in 2017 EFSC Application for Site Certificate

B2H Capacity Interest

Per the terms of the Joint Permit Funding Agreement, each coparticipant (funder) is assigned a permitting interest based on the annual weighted capacity expressed in the project. The permitting interest is determined by the sum of a funder's eastbound capacity interest and westbound capacity interest, divided by the total of all eastbound and westbound capacity interest. Table 5 details the capacity interest of each funder.

Table 5. B2H joint permit funding capacity interests by funder

	Capacity Interest (West-to-East)	Capacity Interest (East-to-West)	Ownership %
Idaho Power	350 MW (Average) 500 MW (Summer) 200 MW (Winter)	0 MW	21.2%
PacifiCorp	300 MW	600 MW	54.5%
BPA	400 MW (Average) 250 MW (Summer) 550 MW (Winter)	0 MW	24.2%
Unallocated	0 MW	400 MW	

Idaho Power's capacity interest is seasonally shaped, with 500 MW of eastbound capacity from April through September and 200 MW of eastbound capacity from January through March and October through December. BPA's capacity interest is seasonally shaped with 250 MW of eastbound capacity from April through September and 550 MW of eastbound capacity from January through March and October through December. PacifiCorp's capacity is constant throughout the year. The sum of the capacity interest in the east-to-west direction is less than the rating (1,000 MW), so the unallocated capacity is divided among the funders based on their respective percentage permitting interest.

The seasonal capacity shaping is a great benefit for Idaho Power's customers, and one of the reasons why the B2H project is such a competitive and cost-effective option in the IRP process. Idaho Power is effectively purchasing 500 MW of capacity (peak summer need) at a cost based on 350 MW of capacity.

Capacity Rating—WECC Rating Process

Idaho Power coordinated with other utilities in the Western Interconnection via a peer-reviewed process known as the WECC Path Rating Process. Through the WECC Path Rating Process, Idaho Power worked with other western utilities to determine the maximum rating (power flow limit) across the transmission line under various stresses, such as high winter or high summer peak load, light load, high wind generation, and high hydro generation on the bulk power system. Based on industry standards to test reliability and resilience, Idaho Power simulated various outages, including the outage of B2H, while modeling these various stresses to ensure the power grid was capable of reliably operating with increased power flow. Through this process, Idaho Power also ensured the B2H project did not negatively impact the ratings of other transmission projects in the Western Interconnection. Idaho Power completed the WECC Path Rating Process in November 2012 and achieved a WECC Accepted Rating of 1,050 MW in the west-to-east direction and 1,000 MW in the east-to-west direction. The B2H project, when constructed, will add significant reliability, resilience, and flexibility to the Northwest power grid.

B2H Design

B2H is routed and designed to withstand catastrophic events, including, but not limited to, the following:

- Lightning
- Earthquake
- Fire
- Wind/tornado
- Ice
- Landslide
- Flood
- Direct physical attack

The following sections provide more information about the design of the B2H transmission line and address each of the catastrophic events listed above.

Transmission Line Design

The details below are not inclusive of every design aspect of the transmission line but provide a brief overview of the design criteria. The B2H project will be designed and constructed to meet or exceed all required safety and reliability criteria.

The basic purpose of a transmission line is to move power from one substation to another for eventual distribution of electricity to end users. The basic components of a transmission line are the structures/towers, conductors, insulators, foundations to support the structures, and shield wires to prevent lighting from striking conductors. See Figure 8 for a cross-section of a transmission line.

For a single-circuit transmission line, such as B2H, power is transmitted via three-phase conductors (a phase can also have multiple conductors, called a bundle configuration). These conductors are typically comprised of a steel core to give the conductor tensile strength and reduce sag and of aluminum outer strands. Aluminum is used because of its conductive properties, and it provides the ability to move more power using a smaller amount of material.

Shield wires, typically either steel or aluminum, and occasionally including fiber optic cables inside for communication between substation equipment, are the highest wires on the structure. Their main purpose is to protect the phase conductors from a lightning strike.

Structures are designed to support the phase conductors and shield wires and keep them safely in the air. For the B2H project, structures were chosen to be steel lattice tower structures, which provide an economical means to support large conductors for long spans over long distances. The typical structure height for B2H is 135 feet tall (structure height will vary depending on location) with a structure located roughly every 1,200 feet on average. The tower height and span length were optimized to minimize ground impacts and material requirements; taller structures could allow for longer spans (less structures on average per mile) but would be costlier due to material requirements. Again, the B2H tower and conductors were engineered to maximize benefits and minimize costs and impacts.

Foundations are the support mechanism that bind the structures to the earth and safely keep the phase conductors and shield wires in the air. For the B2H project, the foundations at each lattice tower structure are planned to be concrete-drilled pier shafts. A cylindrical hole will be drilled at each tower footing of adequate diameter and depth to support the loads applied to the structure from the shield wires and phase conductors. The loads applied to structures via shield wires and conductors are discussed in further detail below.

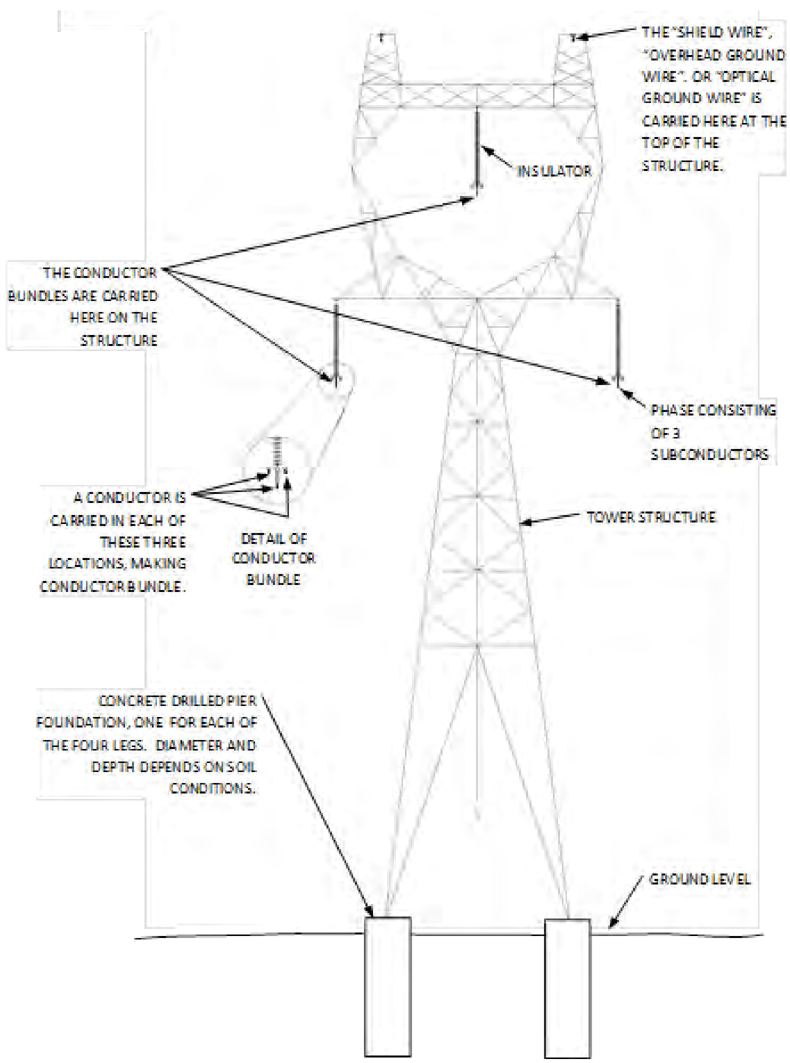

Figure 8. Transmission tower components

Transmission Line Structural Loading Considerations

Reliability and resiliency are designed into transmission lines. Overhead transmission lines have been in existence for over 100 years, and many codes and regulations govern the design and operation of transmission lines. Safety, reliability, and electrical performance are all incorporated into the design of transmission lines. Idaho Power's EFSC application includes an exhaustive list of standards. Several notable standards are as follows:

- American Concrete Institute 318—*Building Code Requirements for Structural Concrete*
- American National Standards Institute (ANSI) standards (for material specs)
- American Society of Civil Engineers (ASCE) Manual No.74—*Guidelines for Electrical Transmission Line Structural Loading*
- National Electrical Safety Code (NESC)
- Occupational Safety and Health Administration (OSHA) 1910.269 April 11, 2014 (for worker safety requirements)
- National Fire Protection Association (NFPA) 780—*Guide for Improving the Lightning Performance of Transmission Lines*

NESC provides for minimum guidelines and industry standards for safeguarding persons from hazards arising from the construction, maintenance, and operation of electric supply and communication lines and equipment. The B2H project will be designed, constructed, and operated at standards that meet, and in most cases, exceed, the provisions of NESC.

Physical loads induced onto transmission structures and foundations supporting the phase conductors and shield wires for the B2H project are derived from three phenomena: wind, ice, and tension. Under certain conditions, ice can build up on phase conductors and shield wires of transmission lines. When transverse wind loading is also applied to these iced conductors, it can produce structural loading on towers and foundations far greater than normal operating conditions produce. Design weather cases for the B2H project exceed the provisions in the NESC. As an example, for a high wind case, NESC recommends 90 miles per hour (mph) winds. The criteria proposed for this project is 100 mph wind on the conductors and 120 mph wind on the structures. There are multiple loading conditions that will be incorporated into the design of the B2H project, including unbalanced longitudinal loads, differential ice loads, broken phase conductors, broken sub-phase conductors, heavy ice loads, extreme wind loads, extreme ice and wind loads, construction loads, and full dead-end structure loads.

Transmission Line Foundation Design

The 500-kV single-circuit lattice steel structures require a foundation for each leg of the structure. The foundation diameter and depth shall be determined during final design and are dependent on the type of soil or rock present. The foundations will be concrete pier foundations designed to comply with the allowable bearing and shear strengths of the soil where placed. Soil borings shall be taken at key locations along the project route, and subsequent soil reports and investigations shall govern specific foundation designs as appropriate.

Common industry practices design transmission line structures to withstand wind and ice loads of NESC or greater and are accepted as more stringent than the potential loads resulting from ground motion due to earthquakes. The 2017 NESC Rule 250A4 observes the structure capacity obtained by designing for NESC wind and ice loads at the specified strength requirements is sufficient to resist earthquake ground motions. Additionally, ASCE Manual No. 74 states transmission structures need not be designed for ground-induced vibrations caused by earthquake motion; historically, transmission structures have performed well under earthquake events,[10, 11] and transmission structure loadings caused by wind/ice combinations and broken wire forces exceed earthquake loads.

Lightning Performance

The B2H project is in an area that historically experiences 20 lightning storm days per year.[12] This is relatively low compared to other parts of the US. The transmission line will be designed to not exceed a lightning outage rate of one per 100 miles per year. This will be accomplished by proper shield wire placement and structure/shield wire grounding to adequately dissipate a lightning strike on the shield wires or structures if it were to occur. The electrical grounding requirements for the project will be determined by performing ground resistance testing throughout the project alignment, and by designing adequately sized counterpoise or using driven ground rods with grounding attachments to the steel rebar cages within the caisson foundations as appropriate.

Earthquake Performance

Experience has demonstrated that high-voltage transmission lines are very resistant to ground-motion forces caused by earthquake, so much so that national standards do not require these

[10] Risk Assessment of Transmission System under Earthquake Loading. J.M. Eidinger, and L. Kemper, Jr. Electrical Transmission and Substation Structures 2012, Pg. 183-192 © ASCE 2013.

[11] Earthquake Resistant Construction of Electric Transmission and Telecommunication Facilities Serving the Federal Government Report. Felix Y. Yokel. Federal Emergency Management Agency (FEMA). September 1990.

[12] USDA RUS Bulletin 1751-801.

forces be directly considered in the design. However, secondary hazards can affect a transmission line, such as landslides, liquefaction, and lateral spreading. The design process considers these geologic hazards using multiple information streams throughout the siting and design process. The current B2H route evaluated geologic hazards using available electronic (geographic information system [GIS]) data, such as fault lines, areas of unstable and/or steep soils, mapped and potential landslide areas, etc. Towers located in potential geologic hazards are investigated further to determine risk. Additional analysis may include field reconnaissance to gauge the stability of the area and subsurface investigation to determine the soil strata and depth of hazard. At the time of this report, no high-risk geologic hazard areas have been identified. If, during the process of final design, an area is found to be high risk, the first option would be to micro-site—route around or span over the hazard. If avoidance is not feasible, the design team would seek to stabilize the hazard. Engineering options for stabilization include designing an array of sacrificial foundations above the tower foundation to anchor the soil or improving the subsurface soils by injecting grout or outside aggregates into the ground. If the geotechnical investigation determines the problematic soils are relatively shallow, the tower foundations can be designed to pass through the weaker soils and embed into competent soils.

Wildfire

The transmission line steel structures are constructed of non-flammable materials, so wildfires do not pose a physical threat to the transmission line itself. However, heavy smoke from wildfires in the immediate area of the transmission line can cause flashover/arcing between the phase conductors and electrically grounded components. Standard operation is to de-energize transmission lines when fire is present in the immediate area of the line. Transmission lines generally remain in-service when smoke is present from wildfires not in the immediate vicinity of the transmission line. When compared to other resource alternatives, B2H may be more resilient to smoke. For instance, solar PV is susceptible to smoke, which can move into areas even if fires are not in the immediate vicinity of the solar generation. For example, the forest fires in the Pacific Northwest in 2017 caused much smoke along the proposed B2H corridor and in the Pacific Northwest in general. The B2H line would likely still operate for the fires not in the immediate area, whereas solar PV would likely operate at a much-reduced capacity while heavy smoke is covering the area.

Wind Gusts/Tornados

Tornados are unlikely along the B2H route. As noted in the Transmission Line Structural Loading Considerations section above, the B2H transmission line is designed to withstand extreme wind loading combined with ice loading.

Ice

Ice formation around the phase conductors and around the shield wires can add a substantial amount of incremental weight to the transmission line, putting extra force on the steel structures and foundations. As described in the Transmission Line Structural Loading Considerations section above, the B2H transmission line is designed to withstand heavy ice loading combined with heavy wind loading.

Landslide

The siting and design process considers geologic hazards, such as landslides, liquefaction, and lateral spreading. See the Earthquake Performance section above. Through the siting and design process, steep, unstable slopes are avoided, especially where evidence of past landslides is evident. During the preliminary construction phase, geotechnical surveys and ground surveys (light detection and ranging [LiDAR] surveys) help verify potentially hazardous conditions. If a potentially hazardous area cannot be avoided, the design process will seek to stabilize the area.

Flood

The identification and avoidance of flood zones was incorporated into the siting process and will be further incorporated into the design process. Foundations and structures can be designed to withstand flood conditions.

Direct Physical Attack

A direct physical attack on the B2H transmission line will remove the line's ability to deliver power to customers. In the case of a direct attack, B2H is fundamentally no different than any other supply-side resource should a direct physical attack occur on a specific resource. However, because the B2H project is connected to the transmission grid, a direct physical attack on any specific generation site in the Pacific Northwest or Mountain West region will not limit B2H's ability to deliver power from other generation in the region. In this context, B2H provides additional ability for generation resources to serve load if a physical attack were to occur on a specific resource or location within the region and therefore increases the resiliency of the electric grid as a whole.

If a direct physical attack were to occur on the B2H transmission line and force the line out of service, the rest of the grid would adjust to account for the loss of the line. Per the WECC facility rating process, the B2H capacity rating is such that an outage of the B2H line would not overload any other system element beyond equipment emergency ratings. Idaho Power also keeps a supply of emergency transmission towers that can be very quickly deployed to replace a damaged tower allowing the transmission line to be quickly returned to service.

B2H Design Conclusions

As evidenced in this section, the B2H project is designed to withstand a wide range of physical conditions and extreme events. Because transmission lines are so vital to our electrical grid, design standards are stringent. B2H will adhere to, and in most cases, exceed, the required codes or standards observed for high voltage transmission line design. This approach to the design, construction, and operation of the B2H project will establish utmost reliability for the life of the transmission line. Additionally, as discussed in the Direct Physical Attack section, transmission lines add to the resiliency of the grid by providing additional paths for electricity should one or more generation resources or transmission lines experience a catastrophic event.

Project Coparticipants

PacifiCorp and BPA Needs

PacifiCorp and BPA are coparticipants in the permitting of the B2H project (also referred to as funders). Collectively, Idaho Power, PacifiCorp, and BPA represent a very large electric service footprint in the western US. The fact that three large utilities have each identified the value of the B2H project indicates the regional significance of the project and the value the project brings to customers throughout the West. Idaho Power, PacifiCorp, and BPA have worked closely to assign the capacity rights of the project to correlate with each party's needs. More information about PacifiCorp's and BPA's needs and interest in the B2H project can be found in the following sections.

PacifiCorp

PacifiCorp is a locally managed, wholly owned subsidiary of Berkshire Hathaway Energy Company. PacifiCorp is a leading western US energy services provider and the largest single owner of transmission in the West, serving 1.9 million retail customers in six western states. PacifiCorp is comprised of two business units: Pacific Power (serving Oregon, Washington, and California) and Rocky Mountain Power (serving Utah, Idaho, and Wyoming). Visit pacificorp.com for more information.

The existing transmission path between the Pacific Northwest and Intermountain West regions is fully used during key operating periods, including winter peak periods in the Pacific Northwest and summer peak in the Intermountain West. PacifiCorp has invested in the permitting of the B2H project because of the strategic value of connecting the two regions. As a potential owner in the project, PacifiCorp would be able to use its share of the bidirectional capacity of B2H to increase reliability and to enable more efficient use of existing and future resources for its customers. PacifiCorp has identified the following list of additional benefits:

- **Customers:** PacifiCorp continues to invest to meet customers' needs, making only critical investments now to ensure future reliability, security, and safety. The B2H project will bolster reliability, security, and safety for PacifiCorp customers as the regional supply mix transitions.

- **Renewables:** PacifiCorp has identified B2H as a strategic project that can facilitate the transfer of geographically diverse renewable resources, in addition to other resources, across PacifiCorp's two balancing authority areas. Transmission line infrastructure, like B2H, is needed to maintain a robust electrical grid while integrating clean, renewable energy resources across the Pacific Northwest and Mountain West states.

- **Regional Benefit:** PacifiCorp, as a member of the regional planning entity NTTG, supports the inclusion of B2H in the NTTG regional plan. From a regional perspective, the B2H project is a cost-effective investment that will provide regional solutions to identified regional needs.

- **Balancing Area Operating Efficiencies:** PacifiCorp operates and controls two balancing areas. After the addition of B2H and portions of Gateway West, more transmission capacity will exist between PacifiCorp's two balancing areas, providing the ability to increase operating efficiencies. B2H will provide PacifiCorp 300 MW of additional west-to-east capability and 600 MW of east-to-west capability to move resources between PacifiCorp's two balancing authority areas.

- **Regional Resource Adequacy:** PacifiCorp is participating in the ongoing effort to evaluate and develop a regional resource adequacy program with other utilities that are members of the Northwest Power Pool. The B2H project is anticipated to provide incremental transmission infrastructure that will broaden access to a more diverse resource base, which will provide opportunities to reduce the cost of maintaining adequate resource supplies in the region.

- **Grid Reliability and Resiliency:** The Midpoint-to-Summer Lake 500-kV transmission line is the only line connecting PacifiCorp's east and west control areas. The loss of this line has the potential to reduce transfers by 1,090 MW. When B2H is built, the new transmission line will provide redundancy by adding an additional 1,000 MW of capacity between the Hemingway substation and the Pacific Northwest. This additional asset would mitigate the impact when the existing line is lost.

- **Oregon and Washington Renewable Portfolio Standards and Other State Legislation:** New legislation and rules for recently passed legislation are being developed to meet state specific policy objectives that are expected to drive the need for additional renewable resources. As these laws are enacted and rules are developed, PacifiCorp will evaluate how the B2H transmission line can help facilitate meeting state policy objectives by providing incremental access to geographically diverse renewable resources and other flexible capacity resources that will be needed to maintain reliability. PacifiCorp believes that investment in transmission infrastructure projects, like B2H and other Energy Gateway segments, are necessary to integrate and balance intermittent renewable resources cost effectively and reliably.

- **EIM:** PacifiCorp was a leader in implementing the western energy imbalance market (EIM). The real-time market helps optimize the electric grid, lowering costs, enhancing reliability, and more effectively integrating resources. PacifiCorp believes the B2H project could help advance the objectives of the EIM and has the potential of benefitting PacifiCorp customers and the broader region.

BPA

BPA is a nonprofit federal power marketing administration based in the Pacific Northwest. BPA provides approximately 28 percent of the electric power used in the Pacific Northwest, which has-an estimated population of over 13 million people. BPA also operates and maintains about three-fourths of the high-voltage transmission in its service area. BPA's area includes Idaho, Oregon, Washington, western Montana, and small parts of eastern Montana, California, Nevada, Utah, and Wyoming. For more information, visit bpa.gov.

Similar to the Idaho Power IRP process for identifying cost-effective service alternatives, BPA identified the B2H project plus associated asset exchange as its top priority for pursuit for serving customers in southeast Idaho. BPA's load and resource mix in southeast Idaho results in a net winter peak demand that exceeds the summer peak demand. BPA's winter peak load couples well with Idaho Power's summer peak load to allow for seasonal shaping of the B2H capacity. Seasonal shaping of capacity would allow BPA to own 550 MW of B2H capacity in the winter and 250 MW of capacity in the summer, dramatically increasing the cost-effectiveness of the project for BPA customers. A recent analysis performed by BPA continues to support the B2H project plus the asset exchange as its top priority for pursuit. For more information about the southeast Idaho load service analysis, visit bpa.gov.[13]

As a federal agency, BPA has responsibilities to comply with NEPA and consider the environmental impacts of its actions, such as participating in transmission line construction. To that end, BPA was a cooperating agency in the development of the B2H EIS and continues to coordinate with the BLM and other federal agencies. BPA will ensure an appropriate environmental review has been conducted on any BPA-proposed action associated with the project and plans to prepare a ROD to the B2H EIS as appropriate and in accordance with the B2H project's permitting schedule.

Coparticipant Agreements

Idaho Power, BPA, and PacifiCorp (collectively, the funders) entered a Joint Permit Funding Agreement on January 12, 2012, with the intent to be joint owners of the B2H line. The agreement was amended on February 13, 2018. The Amended and Restated Boardman to Hemingway Transmission Project Joint Permit Funding Agreement provides for the permitting (state and federal), siting, and acquisition of right-of-way (ROW) over public lands.

Related to the project, but not specific to the B2H permitting activities, the B2H coparticipants entered into an MOU on January 12, 2012, to accomplish the following: 1) explore alternatives to establish BPA eastern Idaho load service from Idaho Power and PacifiCorp's Hemingway

[13] Southeast Idaho Load Service analysis: bpa.gov/transmission/CustomerInvolvement/SEIdahoLoadService/Pages/default.aspx

Substation and 2) consider whether to replace certain transmission arrangements involving existing assets with joint ownership transmission arrangements and other alternative transmission arrangements pursuant to definitive agreements mutually satisfactory to the coparticipants. In other words, in conjunction with the project, the parties agreed to explore cost-effective methods to serve customers by jointly owning facilities other than the B2H project.

Coparticipant Expenses Paid to Date

Approximately $104 million, including allowance for funds used during construction (AFUDC), have been expended on the B2H project through September 30, 2019. Pursuant to the terms of the joint funding arrangements, Idaho Power has received approximately $71 million of that amount as reimbursement from the project coparticipants as of September 30, 2019. Coparticipants are obligated to reimburse Idaho Power for their share of any future project permitting expenditures incurred by Idaho Power.

Cost

Cost Estimate

The total cost estimate for the B2H project is $1 to $1.2 billion dollars, which includes Idaho Power's allowance for funds used during construction (AFUDC). Coparticipant AFUDC is not included in this estimate range. The total cost estimate includes a 20-percent contingency for unanticipated expenses.

In IRP modeling, Idaho Power assumes a 21.2-percent share of the direct expenses, plus its entire AFUDC cost, which equates to approximately $292 million. Idaho Power also included costs for local interconnection upgrades totaling $21 million. Notable items that increased the cost relative to the 2017 IRP cost estimate include: increased steel and aluminum estimates, increased labor cost estimates, increased Longhorn substation estimate, and increased AFUDC.

Transmission Line Estimate

Idaho Power has contracted with HDR to serve as the B2H project's third-party owners' engineer and prepare the B2H transmission line cost estimate. HDR has extensive industry experience, including experience serving as an owner's engineer for BPA for the last seven years. HDR has prepared a preliminary transmission line design that locates every tower and access road needed for the project. HDR used utility industry experience and current market values for materials, equipment, and labor to arrive at the B2H estimate. Material quantities and construction methods are well understood because the B2H project is utilizing BPA's standard tower and conductor design for 500-kV lines. BPA has used the proposed towers and conductor on hundreds of miles of lines currently in-service. HDR was the owner's engineer on recent BPA projects, so HDR is also familiar with the BPA towers and conductor the B2H project is using.

Substation Estimates

Idaho Power prepared the substation cost estimate for the Hemingway Substation, and BPA prepared the Longhorn Substation estimate. Idaho Power used experience designing and constructing the Hemingway Substation in 2013. The Hemingway Substation is designed to accommodate the B2H line terminal in the future. New equipment must be ordered and installed, but no station expansion will be required. The Longhorn Substation is a station proposed by BPA near Boardman, Oregon. BPA owns the land for the Longhorn Substation, but the station has yet to be constructed. BPA proposed the Longhorn Substation to integrate certain wind projects in the immediate area. BPA has extensive experience designing and constructing substations.

Calibration of Cost Estimates

The B2H estimate was reviewed and approved by BPA and PacifiCorp. BPA and PacifiCorp both have recent transmission line construction projects to calibrate against. The recent projects included the following:

- BPA: Lower Monumental–Central Ferry 500-kV line (38 miles, in-service 2015)
- BPA: Big Eddy–Knight 500-kV line (39 miles, in-service 2016)
- PacifiCorp: Sigurd to Red Butte 345-kV line (160 miles, in-service 2015)
- PacifiCorp: Mona to Oquirrh 500-kV line (100 miles, in-service 2013)

Additionally, in early 2017 Idaho Power visited with NV Energy and Southern California Edison to learn from each company's recent experience constructing 500-kV transmission lines in the West. As part of the discussions with each company, Idaho Power calibrated cost estimates and resource requirements.

The two projects were as follows:

- NV Energy: ON Line project (235 miles, 500 kV, in-service 2014)
- Southern California Edison: Devers to Palo Verde (150 miles, 500 kV, in-service 2013)

Costs Incurred to Date

Approximately $104 million, including AFUDC, has been expended on the B2H project through March 31, 2019. The $104 million incurred through September 30, 2019, is included in the $1 to $1.2 billion total estimate. Idaho Power's share of the costs incurred to-date is included B2H IRP portfolio modeling.

Cost-Estimate Conclusions

The cost estimate for B2H has been thoroughly vetted. Idaho Power used third-party contractors with industry experience, relied on PacifiCorp and BPA recent transmission line construction experience, and benchmarked against multiple recent high-voltage transmission line investments in the West to arrive at the B2H construction cost estimate. Material quantities and construction methods are well understood because the B2H project is using BPA's standard tower and conductor design for 500-kV lines. As a conservative measure, Idaho Power has added a 20 percent contingency to cover any unanticipated expenses.

Transmission Revenue

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 transmission capacity additions. For the 2017 IRP, Idaho Power modeled the additional transmission wheeling revenue for the B2H project. In the

IRP filed in June 2019, to be extremely conservative, Idaho Power considered but did not include additional transmission revenues in its modeling. However, in Idaho Power's amended 2019 IRP filing, Idaho Power again chose to include the transmission revenue because it is reflective of the true cost to retail customers. 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.

Idaho Power's FERC transmission rate is calculated as follows:

$$Transmission\ Rate = \frac{Transmission\ Costs\ (\$)}{Transmission\ Usage\ (MW * year)}$$

Per the formula above, since transmission costs will likely go up following the installation of B2H, and transmission usage is assumed to remain the same, Idaho Power's transmission rate will increase. Idaho Power's *existing* transmission wheeling customers will pay this higher transmission rate, resulting in incremental transmission revenue to Idaho Power.

Idaho Power believes short-term usage of the Idaho Power transmission system by third parties could increase because additional capacity is created, further reducing Idaho Power customer rates. However, to be conservative, Idaho Power assumed a constant transmission usage by third parties (no increase or decrease) from 2018 levels.

Potential BPA and Idaho Power Asset Swap

Corresponding with the construction of B2H, Idaho Power and BPA are working to complete an asset swap that would allow Idaho Power to directly access the Mid-C market and avoid a BPA transmission wheeling charge. Such a swap would result in lower purchased-power prices for Idaho Power's customers. In return, BPA would be able to directly serve their load in southeastern Idaho and avoid an Idaho Power wheeling charge. As part of the 2019 IRP analysis, Idaho Power conservatively assumed there would be a wheeling charge to access Mid-C resources across B2H. If an asset swap were to take place, the cost of energy in B2H portfolios would be further reduced and make the B2H project an even more economic.

BENEFITS

High-voltage transmission lines, such as B2H, are used to serve customer demand and to move energy between major markets hubs in the Western Interconnection. If the existing western US were to be overlaid with thousands of new miles of high-voltage transmission lines, the entire WECC could be optimized such that all customers would be served with the most economic resources at all times of the year. The long-term need for new supply-side resources would greatly diminish due to the vast diversity of the loads and resources across the Western Interconnection. Such a grid, of course, is economically infeasible, but projects such as B2H are being developed to allow economic resources to be shared between regions. The existing transmission grid is not perfect, and many areas of the transmission grid are congested. Transmission congestion causes both economic and reliability issues.

Capacity

High-voltage transmission lines provide many significant benefits to the Western Interconnection. The most significant benefit of the B2H project is the capacity benefit of the transmission line. Idaho Power is developing the B2H project to create capacity to serve peak customer demand. The capacity benefit is described in more detail in the Resource Need section.

The Pacific Northwest is a winter peaking region. Pacific Northwest utilities continue to install and build generation capacity to meet winter peak regional needs. Idaho Power operates a system with a summer peak demand. Idaho Power's peak occurs in the late June/early July timeframe, which aligns well with spring hydro runoff conditions when the Pacific Northwest is flush with surplus power capacity. The existing transmission system between the Pacific Northwest and Idaho Power is constrained. Constructing B2H will alleviate this constraint and add 1,050 MW of transfer capability between the Pacific Northwest and Idaho Power (2,050 MW total bi-directionally). Both the Pacific Northwest and Idaho Power will significantly benefit from the addition of transmission capacity between the regions. The Pacific Northwest has already built the power plants and would benefit from selling energy to Idaho Power. Idaho Power needs resources to serve peak load, and a transmission line to existing, underutilized power plants is much more cost effective than building a new power plant.

Clean Energy Future

The benefits of B2H in aggregate reflect its importance to the achievement of Idaho Power's goal to provide 100-percent clean energy by 2045 without compromising the company's commitment to reliability and affordability. Experts, in-depth studies, and even the American

Wind Energy Association, cite the need for an expanded and robust transmission system in a decarbonized future[14].

Avoid Constructing New Resources (and Potentially Carbon-Emitting Resources)

In the early days of the electric grid, utilities built individual power plants to serve their local load. Utilities quickly realized that if they interconnected their systems with low-cost transmission, the resulting diversity of load reduced their need to build power plants. Utilities also realized transmission allowed them to build and share larger, more cost-effective and more efficient power plants. The same opportunities exist today. In fact, B2H is being developed to take advantage of existing diversity.

Table 6 illustrates peak-load estimates, by utility and season, for 2028. The shading represents winter-peaking utilities. As seen in the table, there is significant diversity of load between the regions. The Maximum (MW) column illustrates the minimum amount of generating capacity that would be required if each region were to individually plan and construct generation to meet their own peak load need: 68,000 MW. When all regions plan together, the total generating capacity can be reduced to 64,100 MW, a nearly 6 percent reduction. Transmission connections between the regions, such as B2H, are the key to sharing installed generation capacity.

Table 6. 2028 peak load estimates—illustration of load diversity between western regions

Region	Summer Peak (MW)	Winter Peak (MW)	Maximum (MW)
Avista	2,200	2,400	2,400
BPA	8,400	10,600	10,600
British Columbia	9,700	13,100	13,100
Chelan	300	600	600
Grant	1,200	1,100	1,100
Idaho Power	4,400	3,500	4,400
Nevada	7,600	6,300	7,600
Northwestern Energy	2,000	1,900	2,000
PacifiCorp—East	10,400	8,900	10,400
PacifiCorp—West	3,800	4,000	4,000

[14] awea.org/Awea/media/Policy-and-Issues/Electricity/Transmission-Fact-Sheet.pdf

utilitydive.com/news/as-operators-update-grid-planning-for-renewables-transmission-remains-key/505065/

pv-magazine-usa.com/2019/08/30/clean-energy-groups-allies-call-for-overhaul-of-the-transmission-grid/

Portland General	3,900	3,800	3,900
Puget Sound	3,800	5,300	5,300
Seattle City	1,300	1,600	1,600
Tacoma	600	1,000	1,000
Total	**59,600**	**64,100**	**68,000**

Note: From EEI Load Data used for the WECC 2028 ADS PCM

Load diversity occurs seasonally, as illustrated in Table 6, but it also occurs sub-seasonally and daily. An additional major variable in the Northwest is hydroelectric generation diversity. Over the winter, water accumulates in the mountains through snowpack. As this snow melts, water flows through the region's hydroelectric dams, and northwest utilities generate a significant amount of power. During the spring runoff, generation capacity available in the Pacific Northwest can be significantly higher than in the winter or even late summer. Idaho Power is fortunate to have a peak load that is coincident with the late spring/early summer hydro runoff. Idaho Power's peak load occurs in late June/early July, when hot weather causes major air-conditioning load coincident with agricultural irrigation/pumping load. Idaho Power's time window for a significant peak is quite short, with agricultural irrigation/pumping load starting to ramp down by mid-July.

Utilities have an obligation to serve customer load. This means that utilities are planning to meet peak load needs. As discussed previously, transmission congestion can cause utilities to build additional generation to serve load. In contrast, additional transmission capacity may enable utilities to leverage their transmission system to access generation capacity already constructed by their neighbors. The B2H project is an alternative to building new supply-side resources. As demonstrated in the 2019 IRP, the portfolios that are the most cost-effective, other than B2H portfolios, include new natural gas generation. In this case, B2H provides an alternative to building carbon-emitting supply-side resources.

Improved Economic Efficiency

Transmission congestion causes power prices on opposite sides of the congestion to diverge. Transmission congestion is managed by dispatching higher cost, less efficient resources to ensure the transmission system is operating securely and reliably. Congestion can have a significant cost. During peak summer conditions, the Idaho to Northwest path in the west-to-east direction becomes constrained and power prices in Idaho and to the east will generally be high, while power prices in the Pacific Northwest will be depressed due to a surplus of power availability without adequate transmission capacity to move the power out of the region.
The construction of B2H will help alleviate this constraint and create a win–win scenario where generators in the Pacific Northwest will be able to gain further value from their existing resource, and load-serving entities in the Mountain West region will be able to meet load service needs at a

lower cost. The reverse situation is true as well—the Pacific Northwest will benefit from economical resources from the Mountain West region during certain times of the year.

Renewable Integration

To facilitate a transition from coal and fossil fuel resources to meet Idaho Power and surrounding state clean energy goals, the region requires new and upgraded transmission capacity to integrate and balance intermittent resources like wind and solar. Existing renewable generation is, at times, curtailed due to a lack of transmission capacity to move the energy to load. B2H can facilitate the transfer of geographically diverse renewable resources across the western grid and help ensure our clean energy grid of the future is robust and reliable.

Grid Reliability/Resiliency

Transmission grid disturbances do occur. B2H will increase the robustness and reliability of the regional transmission system by adding additional high-capacity bulk electric facilities designed with the most up-to-date engineering standards. Major 500-kV transmission lines, such as B2H, substantially increase the grid's ability to recover from unexpected disturbances. Unexpected disturbances are difficult to predict, but below are a few examples of disturbances whose impacts would be reduced with the addition of B2H:

1. Loss of the Hemingway–Summer Lake 500-kV line with heavy west-to-east power transfer into Idaho. The loss of the Hemingway–Summer Lake 500-kV transmission line, the only 500-kV connection between the Pacific Northwest and Idaho Power, during peak summer load is one of the worst possible contingencies the Idaho Power transmission system can experience. Once Hemingway–Summer Lake 500-kV disconnects, the transfer capability of the Idaho to Northwest path is reduced by over 700 MW in the west-to-east direction. After the addition of B2H, there will be two major 500-kV connections between the Pacific Northwest and Idaho Power. The Hemingway–Summer Lake 500-kV outage would become much less severe to Idaho Power's transmission system.

2. Loss of the Hemingway–Summer Lake 500-kV line with heavy east-to-west power transfer out of Idaho to the Pacific Northwest. In this disturbance, an existing remedial action scheme (power system logic used to protect power system equipment) will disconnect over 1,000 MW of generation at the Jim Bridger Power Plant to reduce path transfers and protect bulk transmission lines and apparatus. Due to the magnitude of the generation loss, recovery from this disturbance can be extremely difficult. After the addition of B2H, this enormous amount of generation shedding will no longer be required. With two 500-kV lines between Idaho and the Pacific Northwest, the loss of one can be absorbed by the other. Keeping 1,000 MW of generation on the system for major system outages is important for grid stability.

3. Loss of a single 230-kV transmission tower in the Hells Canyon area. Idaho Power owns two 230-kV transmission lines, co-located on the same transmission towers, that connect Idaho to the Pacific Northwest. Because these lines are on a common tower, Idaho Power must consider the simultaneous loss of these lines as a realistic planning event. Historically, such an outage did occur on these lines in 2004 during a day with high summer loads. By losing these lines, Idaho Power's import capability was dramatically reduced, and Idaho Power was forced to rotate customer outages for several hours due to a lack of resource availability. After the addition of B2H, the impact of this outage would be substantially reduced.

Resource Reliability

The forced outage rate of transmission lines has historically been a fraction of traditional generation resources. Availability and contribution to resource adequacy on the power grid, vary significantly by resource type. The North American Electric Reliability Corporation (NERC) has historically tracked transmission availability through a Transmission Availability Data System (TADS) and generation availability through a Generation Availability Data System (GADS) in North America. Outage statistics between transmission and generation differ, as transmission varies in voltage class and total line length, while generators mostly differ in total size and fuel type. A telling sign of the reliability of a generation resource is the equivalent forced outage rate when needed (under demand) (EFORd). The EFORd is calculated based on the amount of time a generator is either de-rated, or completely forced out of service, while needed. De-rating a generator would be considered a partial outage, based on the de-rate amount as a percentage of the total capacity.

Table 7 provides the NERC TADS data for different transmission operating voltages. From the NERC TADS data, a 300-mile, 500-kV transmission line (B2H) would be expected to have an unexpected forced outage rate of 0.4 percent (line miles/100 miles x SCOF x MTTR). Stated differently, the B2H transmission line is expected to have 99.6 percent availability when needed.

Table 7. NERC—AC transmission circuit sustained outage metrics

Voltage Class	Circuit Miles	No. of Circuits	No. of Outages	Total Outage Time (hr)	Frequency (SCOF) (per 100 circuit miles per yr)	Frequency (SOF) (per circuit per yr)	MTTR or Mean Outage Duration (hr)
200–299 kV	103,558	4,477.5	876	14,789.6	0.8459	0.1956	16.9
300–399 kV	56,791	1,623.6	394	19,766.8	0.6938	0.2427	50.2
400–599 kV	32,184	594.7	141	3,957.9	0.4381	0.2371	28.1
600–799 kV	9,451	110.0	28	342.4	0.2963	0.2545	12.2
All Voltages	201,985	6,805.8	1,439	38,856.7	0.7124	0.2114	27.0

By comparison, Table 8, lists the average EFORd for traditional fossil fuel power plants (coal, oil, gas, etc.) and the average EFORd for gas power plants.

Table 8. NERC forced-outage rate information for a fossil or gas power plant

Generation Type	Unit Size	EFORd
Fossil (general)	All Sizes	7.96%
Fossil (general)	100–199 MW	7.49%
Fossil (general)	200–299 MW	5.85%
Gas	All Sizes	9.61%
Gas	1–99 MW	9.72%
Gas	100–199 MW	6.85%

A transmission line with a forced outage rate of less than 1 percent is significantly more reliable than a power plant, which has an EFORd of 7 to 10 percent. Of course, a transmission line requires generating resources to provide energy to the line to serve load. However, energy sold as "Firm" must be backed up and delivered even if a source generator fails. Therefore, Firm energy purchases would have an EFORd consistent with the transmission line, which is much more reliable than traditional supply-side generation. In the management of cost and risk, B2H will provide Idaho Power's operators additional flexibility when managing the Idaho Power resource portfolio.

Reduced Electrical Losses

During peak summer conditions, with heavy power transfers on the Pacific Northwest and Idaho Power transmission systems, the addition of the B2H project is expected to reduce electrical losses by more than 100 MW in the Western Interconnection. This is a considerable savings for the region; 100 MW of generation, that customers ultimately pay for, does not need produced to supply losses alone.

Losses on the power system are caused by electrical current flowing through energized conductors, which in turn create heat. Losses are equal to the electrical current squared times the resistance of the transmission line:

$$Electrical\ Losses = Current^2 \times Resistance$$

From the electrical losses equation above, if the current doubles, the electrical losses will increase by a factor of four. By constructing the B2H line, less efficient (i.e., lower voltage) transmission lines with very large transfers are relieved, reducing the electrical current through these lines and dramatically reducing the losses due to heat.

Flexibility

Advances in technology are pushing certain existing generation resources toward economic obsolescence. Any supply-side resource alternative could face the same economic obsolescence in the future. B2H is an alternative to constructing a new supply-side resource and therefore, reduces the risk of technological obsolescence. B2H will facilitate the transfer of any generation technology, ensuring Idaho Power customers always have access to the most economic resources, regardless of the resource type.

B2H capacity, when not used by B2H owners, will be available (for purchase) to other parties to make economic interstate west-to-east and east-to-west power transfers for more efficient regional economic dispatch. This provides a regional economic benefit to utilities around Idaho Power that is not factored into the analysis. Specifically, the B2H project will make additional capacity available for Pacific Northwest utilities to sell energy to southern and eastern markets in the West, and for Pacific Northwest utilities to purchase energy from southern and eastern markets to meet their winter peak load service needs (southern and eastern WECC entities are mostly summer peaking). Idaho Power customers benefit from any third-party transmission purchases as the incremental transmission revenue acts to offset retail customer costs.

The existing electric system is heavily used. Because the system is so heavily used, new transmission line infrastructure, like B2H, creates additional operational flexibility. B2H will increase the ability to take other system elements out of service to conduct maintenance and will provide additional flexibility to move needed resources to load when outages occur on equipment.

EIM

Idaho Power views the regional high-voltage transmission system as critical to the realization of EIM benefits, and the expansion of this transmission system (i.e., B2H) facilitates the realization of these benefits. As fluctuations in supply and demand occur for EIM participants, the market system will automatically find the best resource(s) from across the large-footprint EIM region to meet immediate power needs. Additional Northwest utilities are joining the EIM increasing the value the transmission system provides. This activity optimizes the interconnected high-voltage system as market systems automatically manage congestion, helping maintain reliability while also supporting the integration of intermittent renewable resources and avoiding curtailing excess supply by sending it to where demand can use it.

Idaho Power notes that EIM participation does not alter its obligations as a balancing authority (BA) required to comply with all regional and national reliability standards. Participation in the western EIM does not change NERC or WECC responsibilities for resource adequacy, reserves, or other BA reliability-based functions for a utility.

B2H Complements All Resource Types

Utility-scale resource installations allow economies of scale to benefit customers in the form of lower cost per watt. For instance, residential rooftop solar is growing in popularity, but the economics of rooftop solar are outweighed by the economics of utility-scale solar installation.[15] Large transmission lines allow the most economical resources to be sited in the most economical locations. As an example, single-axis tracking utility-scale solar in Salem, Oregon, is expected to have a capacity factor of approximately 15 percent (where the capacity factor is the amount of time the system generates over the course of a year). Comparatively, the same single-axis tracking utility-scale solar system in Boise, Idaho, has a capacity factor of approximately 19 percent[16]. If solar system prices are assumed to be equivalent in Salem and Boise, a Boise installation would generate over 25 percent more energy over the course of the year. Transmission lines provide the ability to move the most economical resources around the region.

Idaho Power views transmission lines like B2H as a complement to any resource type that allows access to the least-cost and most efficient resource, as well as regional diversity, to benefit all customers in the West.

B2H Benefits to Oregon

Economic and Tax Benefits

The B2H project will result in positive economic impacts for eastern Oregon communities in the form of new jobs, economic support associated with infrastructure development (i.e., lodging and food), and increased annual tax benefits to each county for project-specific property tax dollars. The annual tax benefit for the non-BPA owned portion of the line is shown in Table 9 below. BPA, as a federal entity, does not pay taxes, so BPA's 25 percent project interest is excluded from the estimates. Idaho Power anticipates the project will add about 500 construction jobs, which will provide a temporary increase in spending at local businesses.

Table 9. Projected annual B2H tax expenditures by county*

Oregon County	Property Tax (excluding BPA's 25% ownership interest)
Morrow	$270,295
Umatilla	$569,656
Union	$629,410
Baker	$1,778,282

[15] The National Renewable Energy Laboratory (NREL) estimates the cost of residential rooftop solar (PV) is nearly 2.5 times the cost of utility-scale solar on a $/Watt basis (NREL, Annual Technology Baseline: Electricity: 2019).

[16] NREL, System Advisory Model

Malheur	$893,567
Total Oregon Tax Benefit	**$4,141,210**

***The property tax valuation process for utilities is determined differently than locally assessed commercial and residential property. The Oregon Department of Revenue determines the property tax value for Idaho Power Company's ("Idaho Power" or "Company") property (transmission, distribution, production, etc.) as one lump sum value (i.e., not by individual assets)..The Oregon Department of Revenue then apportions and remits Idaho Power's lump sum assessed value to each county. It is from those values that the county generates property tax bills for the Company. Idaho Power converts its Oregon property tax payment by county into an internal rate that can be applied to Idaho Power's transmission, distribution, and production book investment to estimate taxes. This internally calculated tax rate is what was applied to the Boardman to Hemingway ("B2H") estimated book investment (project cost) to estimate property taxes. The table above summarizes the tax value derivation. For estimation purposes, the estimated property taxes are assumed at Idaho Power tax rates. PacifiCorp property taxes may differ from Idaho Power's property taxes. It is Idaho Power's understanding that BPA, as a federal agency, is not obligated to pay taxes on its ownership. Therefore, the total estimated tax amount is discounted by BPA's 25 percent ownership interest.

Local Area Electrical Benefits

The B2H project will add 1,050 MW of additional transmission connectivity between the BPA and Idaho Power systems. Currently, the transmission connections between BPA and Idaho Power are fully used for existing customer commitments. Idaho Power currently serves customers in Owyhee County, Idaho, and Malheur County and portions of Baker County in Oregon. PacifiCorp, through Pacific Power, serves portions of Umatilla County. BPA provides transmission service to local cooperatives in the remainder of the project area in Morrow, Umatilla, Union, and Baker counties. Below is a summary of how these areas will benefit directly from B2H.

La Grande and Baker City are served by the Oregon Trails Electric Cooperative (OTEC). Portions of Morrow County and Umatilla County are served by Umatilla Electric Cooperative (UEC) and Columbia Basin Electric Cooperative (CBEC). OTEC, UEC, and CBEC pay BPA's network transmission rate to receive power and transmission service from the BPA system. If BPA finds less expensive solutions to meet service obligations to customers in southeast Idaho and Wyoming, costs are kept low for other BPA customers, including OTEC, UEC, and CBEC. In other words, BPA customers in Oregon benefit by finding a low-cost solution for customers in Idaho and Wyoming. BPA's financial analysis to date has projected that a share of the B2H project with asset exchange appears the most cost-effective, long-term solution to serve customers in southeast Idaho and eastern Wyoming. Correspondingly, OTEC, UEC, and CBEC customers would also benefit from this cost-effective solution.

The B2H project provides economic development opportunities. The cost of power is a major factor in economic development and, as discussed previously, B2H, as a low-cost resource alternative, will keep power costs low compared to more expensive alternatives.

Capacity must be available on the existing system for additional economic development to take place. In Union and Umatilla counties, BPA's McNary–Roundup–La Grande 230-kV line has limited ability to serve additional demand in the Pendleton and La Grande areas but is currently capable of meeting the 10-year load forecast. The B2H project will increase the transfer capability through eastern Oregon by 1,050 MW. This capacity will provide a significant regional benefit to the entire Northwest and specifically benefit load service to eastern Oregon and southern Idaho. It is possible this added capacity resulting from the B2H project could be used to serve additional demand in Union and Umatilla counties.

Portions of Baker County are served by Idaho Power, from Durkee to the east. BPA currently provides energy to OTEC, which serves Baker City via transmission connections between the Northwest and Idaho Power's transmission system. At this point, the existing transmission connections between the Northwest and Idaho Power are fully used for existing load commitments, with very little ability to meet load growth requirements. The B2H project will increase the transmission connectivity between the Northwest and Idaho Power by 1,050 MW, which will allow BPA to serve additional demand in Baker City.

Finally, additional transmission capacity can create opportunities for new energy resources, which can add to the county tax base and create new jobs.

RISK

Risk is inherent in any infrastructure development project. The sections below address various risks associated with the B2H project. Combining the analysis below with the risk analysis conducted in the 2019 IRP, Idaho Power believes B2H is the lowest-risk resource to meet Idaho Power' resource needs.

Capital-Cost Risk

The capital-cost estimate for the B2H project has been well vetted. See the Cost section for an explanation of how the B2H project cost estimate was determined. Idaho Power's share of the B2H project is $292 million, including Idaho Power's AFUDC. Idaho Power also included costs for local interconnection upgrades totaling $21 million.

The B2H project has considerable capital-cost bandwidth. Idaho Power notes that the B2H capital cost includes a 20 percent cost contingency, which is not included for other resource options considered. Based on NPV analysis over the 20-year planning horizon, Idaho Power's cost share of the B2H project could almost double, and the least-cost B2H portfolio would still be more cost-effective than the least-cost, non-B2H portfolio under planning assumptions.

Market Price Risk

Idaho Power performed two separate risk analyses on the 24 resource portfolios developed by the AURORA model for the 2019 IRP. Under the first risk analysis, total portfolio costs (i.e., total of fixed and variable costs) were modeled under three higher-priced natural gas and carbon cost scenarios. The second risk analysis was a stochastic risk analysis, where total portfolio costs were modeled for 20 iterations, or futures, on the following stochastic risk variables: natural gas price, customer load, and hydro condition. These analyses are described in Chapter 9 of the Amended 2019 IRP.

Idaho Power emphasizes that wholesale electric market prices are not specified inputs to the AURORA model, but rather are output by the model in response to various factors and are strongly driven by positive correlations with natural gas price and carbon cost, and a negative correlation with hydro condition. Thus, the risk analyses performed by Idaho Power are considered to study the relative exposure of the IRP resource portfolios to the studied inputs (e.g., natural gas price), and by extension to wholesale electric market prices output by the AURORA model.

The risk analyses performed for the 2019 IRP indicate that total portfolio costs, specifically variable costs associated with the operation of portfolio resources (e.g., cost of imported wholesale electric energy), are markedly affected by the studied risk variables. For example, the total portfolio costs for Portfolio 16-4 ranged from $5.997 billion under planning case conditions for natural gas price and carbon cost to $9.153 billion under high case conditions for both inputs (Table 9.9 of Amended 2019 IRP). Similarly, Portfolio 16-4 costs ranged across the 20 stochastic iterations from $5.63 billion to $7.35 billion (Figure 9.6 of the Amended 2019 IRP). Thus, the risk analyses indicate that the studied risk variables strongly influence portfolio costs. However, the analyses also importantly suggest that the relative exposure to the studied risk variables, including by extension wholesale electric market prices, does not dramatically favor one portfolio over another; Portfolio 16-4 and other B2H-based portfolios exhibit similar ranges in their portfolio costs across the risk scenarios as B2H-alternative portfolios.

Liquidity and Market Sufficiency Risk

The Pacific Northwest is a winter peaking region. Pacific Northwest utilities continue to install and build generation capacity to meet winter peak regional needs. Idaho Power operates a system with a summer peak. Idaho Power's peak occurs in the late June/early July timeframe. The Idaho Power summer peak aligns with the Mid-C hydro runoff conditions when the Pacific Northwest is flush with surplus power capacity. The existing transmission system between the Pacific Northwest and Idaho Power is constrained. Constructing B2H will alleviate this constraint and add 1,050 MW of total transfer capability between the Pacific Northwest and the Intermountain West region. The Pacific Northwest and Idaho Power will significantly benefit from the addition of transmission capacity between the regions. The Pacific Northwest has constructed power plants to meet winter needs and would benefit from selling energy to Idaho Power in the summer. Idaho Power needs generation capacity to serve summer peak load, and a transmission line to existing underutilized power plants is much more cost-effective than building a new power plant.

See the Market Overview section of this appendix for more information about the Mid-C market hub liquidity. Based on the risk assessment, Idaho Power believes sufficient market liquidity exists.

The following data points will address the market sufficiency risk.

Data Point 1. Peak Load Analysis from Table 6

Referencing Table 6 from the Benefits section above, British Columbia and other utilities in the Pacific Northwest[17] have forecast 2028 winter peaks that exceed their forecast 2028 summer peaks by a combined 8,300 MW. Given the difference in seasonal peaks, coupled with Columbia runoff hydro conditions aligning with Idaho Power's summer peak, resource availability in the Pacific Northwest during Idaho Power's summer peak is likely.

[17] Load serving entities from Table 6 included in stated figure are Avista, BPA, British Columbia, Chelan, Grant, PacifiCorp—West, Portland General, Puget Sound, Seattle City, and Tacoma.

Data Point 2. Pacific Northwest Power Supply Adequacy Assessment for 2023—Northwest Power Conservation Council Report

Idaho Power's review of recent assessments of regional resource adequacy in the Pacific Northwest included the *Pacific Northwest Power Supply Adequacy Assessment for 2023* conducted by the Northwest Power and Conservation Council (NWPCC) Resource Adequacy Advisory Committee (RAAC). The NWPCC RAAC uses a loss-of-load probability (LOLP) of 5 percent as a metric for assessing resource adequacy. The analytical information generated by each resource adequacy assessment is used by regional utilities in their individual IRPs.

The RAAC issued the *Pacific Northwest Power Supply Adequacy Assessment of 2023* report on June 14, 2018,[18] which reports the LOLP starting in operating year 2021 will exceed the acceptable 5 percent threshold and remain above through operating year 2023. Additional capacity needed to maintain adequacy is estimated to be on the order of 300 megawatts in 2021 with an additional need for 300 to 400 MW in 2022. The RAAC assessment includes all projected regional resource retirements and energy efficiency savings from code and federal standard changes but does not include approximately 1,340 MW of planned new resources that are not sited and licensed, and approximately 400 MW of projected demand response.

While it appears that regional utilities are well positioned to face the anticipated shortfall beginning in 2021, different manifestations of future uncertainties could significantly alter the outcome. For example, the results provided above are based on medium load growth. Reducing the 2023 load forecast by 2 percent results in an LOLP of under 5 percent.

From Idaho Power's standpoint, even with the conservative assumptions adopted in the *Pacific Northwest Power Supply Adequacy Assessment of 2023* report, the LOLP is zero for the critical summer months (see Figure 9). The NWPCC analysis indicates that the region has a surplus in the summer; this is the reason that B2H works so well as a resource in Idaho Power's IRP.

[18] NWPCC. Pacific Northwest power supply adequacy assessment for 2023. Document 2018-7. nwcouncil.org/sites/default/files/2018-7.pdf. Accessed April 25, 2017.

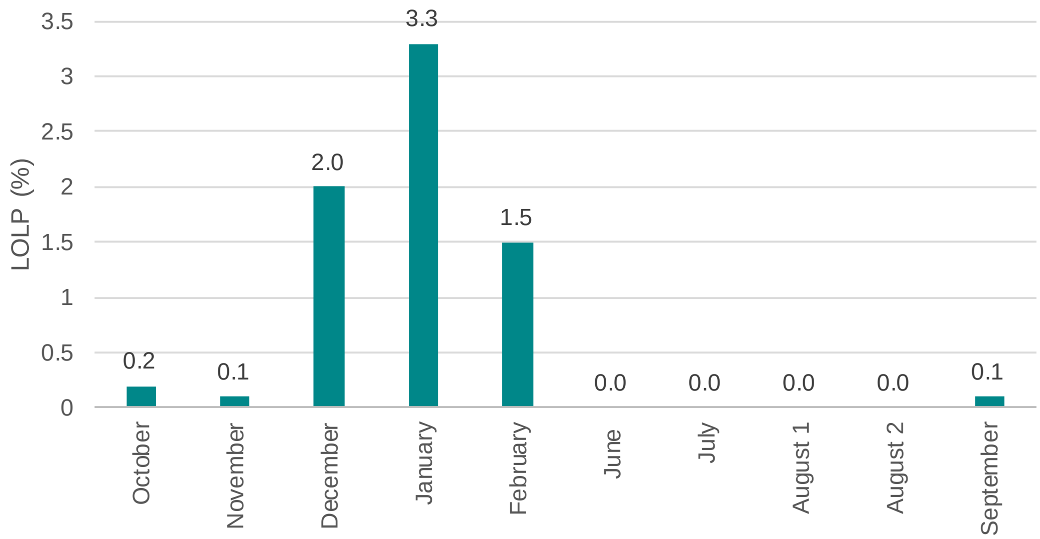

Figure 9. LOLP by month—Pacific Northwest Power Supply Adequacy Assessment of 2023

Data Point 3: 2018 Pacific Northwest Loads and Resources Study—BPA

Idaho Power's review of recent regional resource adequacy assessments also included the *Pacific Northwest Loads and Resources Study* by the BPA (White Book). The most recent BPA adequacy assessment report was released in April 2019 and evaluates resource adequacy from 2020 through 2029.[19] Idaho Power concludes from this analysis that: 1) summer capacity will be available in the future, and 2) additional summer capacity will likely be added as the region adds resources to meet winter peak demand. BPA considers regional load diversity (i.e., winter- or summer-peaking utilities) and expected monthly production from the Pacific Northwest hydroelectric system under the critical case water year for the region (1937). Canadian resources are excluded from the BPA assessment. New regional generating projects are included when those resources begin operating or are under construction and have a scheduled on-line date. Similarly, retiring resources are removed on the date of the announced retirement. Resource forecasts for the region assume the retirement of the following coal projects over the study period:

[19] BPA. 2018 Pacific Northwest loads and resources study (2018 white book). Technical Appendix, Volume 2: Capacity Analysis. bpa.gov/p/Generation/White-Book/wb/2018-WBK-Technical-Appendix-Volume-2-Capacity-Analysis-20190403.pdf. Accessed June 20, 2019

Table 10 Coal retirement forecast

Resource	Retirement Date
Centralia 1	December 1, 2020
Boardman	January 1, 2021
Valmy 1	January 1, 2022
Colstrip 1	June 30, 2022
Colstrip 2	June 30, 2022
Centralia 2	December 1, 2025
Valmy 2	January 1, 2026

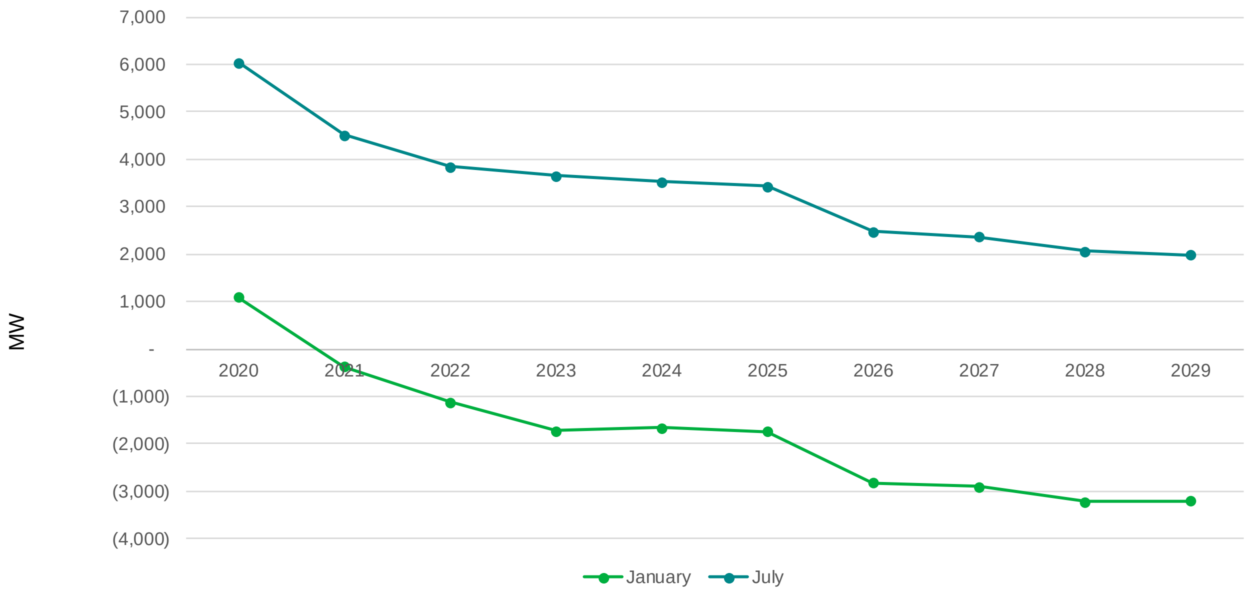

Figure 10. BPA white book PNW surplus/deficit one-hour capacity (1937 critical water year)

Data Point 4: FERC Form 714 Load Data

For illustrative purposes, Idaho Power downloaded peak load data reported through FERC Form 714 for the major Pacific Northwest entities in Washington and Oregon: Avista, BPA, Chelan County PUD, Douglas County PUD, Eugene Water and Electric Board, Grant County PUD, PGE, Puget Sound Energy, Seattle City Light, and Tacoma (PacifiCorp West data was unavailable). The coincident sum of these entities' total load is shown in Figure 11.

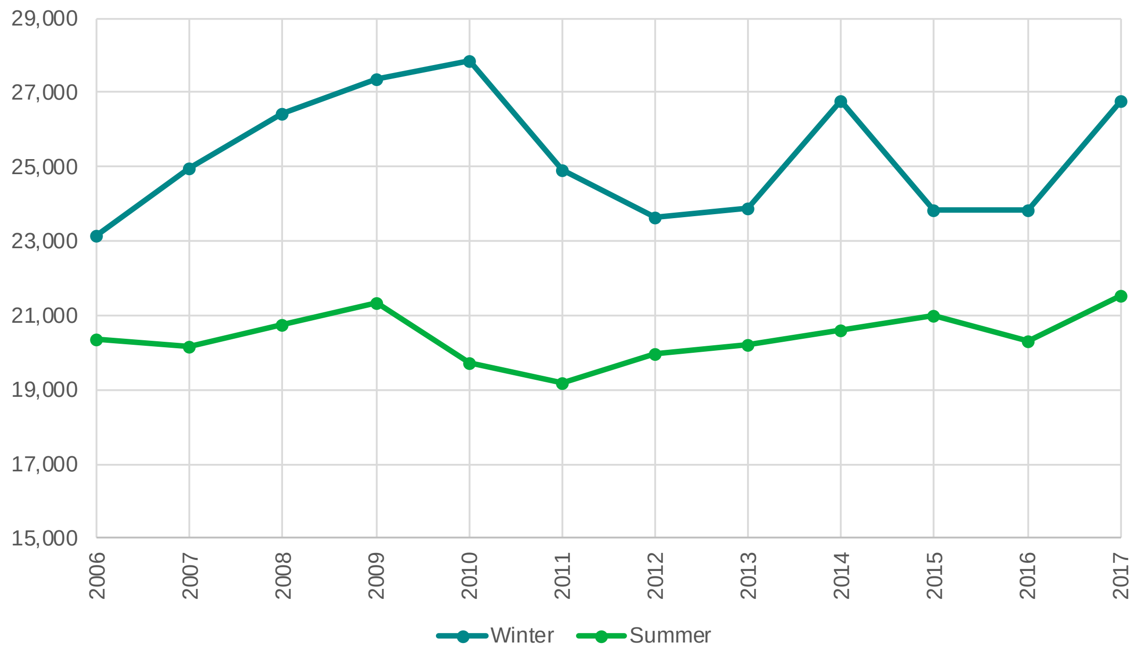

Figure 11. Peak coincident load data for most major Washington and Oregon utilities

Figure 11 illustrates a wide difference between historical winter and summer peaks for the Washington and Oregon area in the region. Other considerations, not depicted, include Canada's similar winter- to summer-peak load ratio (winter peaking), and the increased ability of the Pacific Northwest hydro system in late June through early July compared to the hydro system's capability in the winter (more water in summer compared to winter).

Data Point 5: Northwest and California Renewable Portfolio Standards

The adoption of more aggressive RPS goals by states such as Oregon, California, and Washington will drive policy-driven resource additions. The RPS goals will also likely result in more solar generation throughout the region and may also result in the addition of dispatchable flexible ramping resources, such as the Port Westward 2 power plant installed by Portland General Electric in 2014.

Market Sufficiency and Liquidity Conclusions

Based on the analysis summarized above and in the Markets section of this report, Idaho Power believes there will be sufficient resources in the future to source the B2H transmission line. Also, because the market balances supply and demand based on a market clearing price, liquidity risk can be modeled in economic terms. Should demand be greater than supply at the Mid-C energy hub in the future, market hub prices would reflect the scarcity accordingly (higher prices). As discussed in the Market Price Risk section, risk analyses conducted in the 2019 IRP indicates B2H remains cost competitive over a wide range of risk scenarios, including variations in market prices because of variations in input variables.

Coparticipant Risks

Idaho Power, BPA, and PacifiCorp, collectively referred to as coparticipants or funders, are fully engaged in permitting activities. and have had ongoing construction and operating agreement discussions.

Under the terms of the Joint Permitting Agreement, the funders may withdraw from the agreement at any time and for no reason. In such an event, the withdrawing funder(s) shall pay all costs up to the last day of the month of withdrawal. If one or more of these funders does not move forward with construction, withdrawals from the project, all rights, title, and interest will be transferred to the remaining funder(s) such that the remaining funder(s) shall have 100 percent of the permitting interest in the permitting project. The remaining funders may then seek other funder(s) and/or proceed with construction.

In the event that either BPA or PacifiCorp were to decide not to move forward with the project, Idaho Power believes other parties may have interest in potential ownership in B2H. At least one additional party was involved in the original negotiations that ultimately lead to the current three-party 2012 Joint Funding Agreement. Additionally, Idaho Power has had discussions with other entities that may have interest in the B2H project. Even if all three of the current funders remain committed to the project, it is possible that additional partners may commit to the project. Any consideration of additional project coparticipants would be discussed and agreed on by the current funders.

Changes in ownership structure could change cost allocation percentages. Refer to the Capital-Cost Risk section of this appendix for more information about capital-cost risk. For any potential changes in ownership structure, Idaho Power will evaluate the potential ownership cost and capacity allocation, and assuming cost-effective for Idaho Power customers, would request approval from the Oregon and Idaho public utility commissions for any modification in ownership.

Siting Risk

Siting any new infrastructure projects comes with siting risk. The BLM ROD, which was released on November 17, 2017, was a significant milestone in the B2H project development and greatly minimized siting risk by authorizing the project on 85.6 miles of BLM-administered land. The U.S. Forest Service also issued a ROD authorizing the project on National Forest land in 2018, and the U.S. Navy issued a ROD in 2019 authorizing the project on Navy land.
The Oregon site certificate process is the next major step in siting, and in 2019, ODOE issued a Draft Proposed Order recommending approval of the project. While the recommendations in the Draft Proposed Order are subject to review and change by EFSC, reaching the Draft Proposed Order stage itself is a major milestone in the state permitting process and the recommendations

are certainly encouraging. Idaho Power believes that the significant progress in both federal and state permitting processes minimizes future siting risk.

Schedule Risk

As of the date of this appendix, Idaho Power has schedule scenarios for B2H in-service dates in 2026 or later. At a high level, remaining activities prior to energization are: permitting, coparticipant agreements, preliminary construction, material procurement, and construction.

The permitting phase of the project is ongoing. For federal permitting, the B2H project recently achieved the biggest schedule milestone to date with the release of BLM's ROD on November 17, 2017 and subsequent Right-of-Way Grant in January 2018. The ROD and ROW Grant formalized the BLM-led NEPA process and established a BLM Agency Preferred route on public and private property. The U.S. Forest Service ROD was issued in November 2018 and a right-of-way easement was issued in May 2019. A Navy ROD was issued in September 2019 and a Navy easement is expected in early 2020.

For the State of Oregon permitting process, the B2H project also achieved a considerable milestone in summer 2017 with the submittal of the Amended Application for Site Certificate to the ODOE and an application completeness determination from ODOE in fall 2018. The ODOE also issued a Draft Proposed Order in May 2019. A Proposed Order is expected in early 2020 and a Final Order and Site Certificate are expected in 2021. The EFSC permitting process is a critical path schedule activity. Schedule risk exists for the EFSC permitting process if the ODOE does not issue a Site Certificate in 2021.

With the receipt of the BLM ROD and ROW easement, and a Draft Proposed Order from ODOE, sufficient route certainty exists to continue with preliminary construction tasks. In 2019, Idaho Power began the process of acquiring necessary federal authorizations to conduct geotechnical explorations. At the time of writing, Idaho Power is in the process of developing a detailed design (i.e., preliminary construction) bid package. In 2020, Idaho Power plans to initiate the following activities: detailed design, ROW acquisition, LIDAR (aerial mapping), legal surveys, and geotechnical investigation. The B2H co participants have not formally decided on the construction contracting method for the project, so the preliminary construction and construction schedule activities remain preliminary until contracts are in place. Currently, Idaho Power believes a 2026 in service date is achievable.

Catastrophic Event Risk

As detailed in B2H Design section of this appendix, the B2H transmission line is designed to withstand a variety of extreme weather conditions and catastrophic events. Like most infrastructure, the B2H project is susceptible to direct physical attack. However, unlike some other supply-side resources, B2H adds to the resiliency of the electrical grid by providing additional capacity and an additional path to transfer energy throughout the region should a physical attack or other catastrophic event occur elsewhere on the system. Additionally, Idaho Power also keeps a supply of emergency transmission towers that can be quickly deployed to replace a damaged tower, allowing the transmission line to be quickly returned to service.

Project Activities

Schedule Update

Permitting

The B2H projected achieved a major milestone with the release of the BLM ROD on November 17, 2017 and the ROW Grant on January 9, 2018. These actions formalized the conclusion of the siting process and federally required NEPA process. The BLM ROD and ROW Grant provides the B2H project the ability to site the project on BLM-administered land. The BLM-led NEPA process took nearly 10 years to complete and involved extensive stakeholder input. Refer to the Project History and Route History sections of this report for more information on project history and public involvement. With the issuance of the U.S. Forest Service ROD and easement, and the issuance of the U.S. Navy ROD, all federal decision records have been achieved..

For the State of Oregon permitting process, Idaho Power submitted the Amended Application for Site Certificate to the ODOE in summer 2017 and ODOE issued a Draft Proposed Order in May 2019. A Proposed Order is expected in early 2020 and a Final Order and Site Certificate is expected in 2021.

The NEPA and EFSC processes are separate and distinct permitting processes and not necessarily designed to work simultaneously. At a high level, the NEPA EIS process evaluates reasonable alternatives to determine the best alternative (the Agency Preferred Alternative) at the end of the process. Comparative analysis is conducted at a “desktop” level. Information is brought into the process on a phased-approach. Detailed analysis must be conducted on the final route prior to construction, generally once final design is complete.

The Oregon EFSC process is a standards-based process based on a fixed site boundary. For a linear facility, like a transmission line, the process requires the transmission line boundary to be established (a route selected) and fully evaluated to determine if the project meets established standards. The practical effect of the EFSC standards-based process required the NEPA process be far enough along to conduct field studies and other technical analyses to comply with standards. Idaho Power conducted field surveys and prepared the EFSC application in parallel with the NEPA process. The EFSC application is lengthy, coming in at over 20,000 pages.

Post-Permitting

To achieve an in-service date in 2026, preliminary construction activities must commence parallel to EFSC permitting activities. Preliminary construction activities include, but are not limited to, the following:

- Geotechnical explorations
- Detailed ground surveys (light detection and ranging (LiDAR) aerial mapping

- Sectional surveys
- ROW acquisition activities
- Detailed design
- Construction bid package development and construction contractor selection

After the Oregon permitting process and preliminary construction activities conclude, construction activities can commence. Construction activities include, but are not limited to, long-lead material acquisition, transmission line construction, and substation construction. The preliminary construction activities must commence several years prior to construction. The material acquisition and construction activities are expected to take 3 to 4 years. The specific timing of each of the preliminary construction and construction activities will be coordinated with the project coparticipants.

CONCLUSIONS

This B2H 2019 IRP appendix provides context and details that support evaluating the B2H transmission line project as a supply-side resource, explores many of the ancillary benefits offered by the transmission line, and considers the risks and benefits of owning a transmission line connected to a market hub in contrast to direct ownership of a traditional generation resource.

As discussed in this report, once operational, B2H will provide Idaho Power increased access to reliable, low-cost market energy purchases from the Pacific Northwest. B2H (including early versions of the project) has been a cost-effective resource identified in each of Idaho Power's Integrated Resource Plans (IRP) since 2006 and continues to be a cornerstone of Idaho Power's 2019 IRP preferred resource portfolio. In the 2019 IRP, B2H was identified as the least-cost and least-risk resource to serve future capacity and energy future needs. When compared to other individual resource options, B2H is also the least-cost option in terms of both capacity cost and energy cost. B2H is expected to have a capacity cost that is nearly 60 percent lower than either a combined-cycle gas plant or utility-scale solar alternatives.[20] In addition to the B2H capacity benefits, B2H is expected to have the lowest levelized cost of energy—lower than the expected costs for a combined-cycle gas plant and utility-scale solar.[21]

The B2H project brings additional benefits beyond cost-effectiveness. The B2H project will increase the efficiency, reliability, and resiliency of the electric system by creating an additional pathway for energy to move between major load centers in the West. The B2H project also provides the flexibility to integrate any resource type and move existing resources during times of congestion, benefiting customers throughout the region. Idaho Power believes B2H provides value to the system beyond any individual resource because it enhances the flexibility of the existing system and facilitates the delivery of cost-effective resources not only to Idaho Power customers, but also to customers throughout the Pacific Northwest and Mountain West regions.

The company must demonstrate a need for the project before EFSC will issue a Site Certificate authorizing the construction of a transmission line. The need demonstration can be met through a commission acknowledgement of the resource in the company's IRP.[22] In this case, Idaho Power seeks to satisfy EFSC's least-cost plan rule's requirement through an acknowledgement of it's Amended 2019 IRP.

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[20] Amended 2019 IRP Figure 7.5.

[21] Amended 2019 IRP Figure 7.6

[22] OAR 345-023-0020(2).

Appendix D-1. Transmission line alternatives to the proposed B2H 500-kV transmission line

Table D-1

Comparison of Transmission Line Capacity Scenarios—New Lines from Longhorn to Hemingway

Scenario	Line Capacity[1]	Potential Path 14 West-East Increase[2]	Losses on New Circuit(s)[3]
a. Longhorn to Hemingway 230 kV single circuit	956 MW	525 MW	10.8%
b. Longhorn to Hemingway 230 kV double circuit	1,912 MW	915 MW	9.5%
c. Longhorn to Hemingway 345 kV single circuit	1,434 MW	730 MW	6.6%
d. Longhorn to Hemingway 500 kV single circuit	3,214 MW	1,050 MW	4.2%
e. Longhorn to Hemingway 500 kV—two separate lines	6,428 MW	2,215 MW	3.7%
f. Longhorn to Hemingway 500 kV double circuit	6,428 MW	1,235 MW	2.9%
g. Longhorn to Hemingway 765 kV single circuit	4,770 MW	1,200 MW	2.4%

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

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

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

Table D-2

Comparison of Transmission Line Capacity Scenarios – Rebuild Existing Lines to the Northwest

Scenario	Line Capacity[1]	Potential Path 14 Increase[2]	Losses on New Circuit(s)[3]	Length of Line/ New ROW[4]
h. Replace Oxbow-Lolo 230 kV with Hatwai - Hemingway 500 kV	3,214 MW	430 MW W-E 675 MW E-W	3.8%	255 Miles/136 Miles
i. Replace Oxbow-Lolo 230 kV with Hatwai - Hemingway 500 kV - No double circuiting with existing lines	3,214 MW	710 MW W-E 745 MW E-W	4.1%	255 Miles/167 Miles
j. Replace Walla Walla to Brownlee 230 kV with Sacajawea Tap-Hemingway 500 kV	3,214 MW	400 MW W-E 675 MW E-W	3.5%	288 Miles/150 Miles
k. Replace Walla Walla to Pallette 230 kV with Sacajawea Tap-Hemingway 500 kV - No double circuiting with existing lines	3,214 MW	720 MW W-E 730 MW E-W	3.8%	288 Miles/181 Miles
l. Build double circuit 500 kV/230 kV line from McNary to Quartz. Build 500kV from Quartz to Hemingway.	3,214 MW	765 MW W-E 870 MW E-W	3.9%	298 Miles/168 Miles

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

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

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

[4] In addition to utilizing existing 230 kV right-of-way ("ROW"), each of the scenarios above will require new ROW to be obtained.

Appendix D-2. Detailed list of notable project milestones

- June, 2006 – Idaho Power files the 2006 IRP – Transmission line between Boise and Pacific Northwest identified in preferred resource portfolio (this transmission line eventually became the Boardman to Hemingway project)
- December 19, 2007 – Idaho Power Completes the B2H Preliminary Plan of Development
- 2008 – Idaho Power files the 2008 IRP Update
- August 28, 2008 – Idaho Power submits Notice of Intent to EFSC to submit an Application for Site Certificate.
- September 12, 2008 – Notice of Intent published in the Federal Register for BLM to prepare an Environmental Impact Statement for B2H
- April 10, 2009 – Public Scoping Report for B2H EIS completed by Tetra Tech
- December 30, 2009 – Idaho Power files the 2009 IRP – B2H Project identified in preferred resource portfolio
- June 2010 – Idaho Power completes the B2H Preliminary Plan of Development
- July 2010 – Idaho Power submits a NOI to apply for a Site Certificate for B2H to ODOE
- August 2010 – Idaho Power completes the B2H Siting Study
- August 2010- February 2011 – Idaho Power completes the Community Advisory Process
- February 2011 – Idaho Power completes a Revised Plan of Development for B2H
- June 30, 2011 – Idaho Power files the 2011 IRP – B2H Project identified in preferred resource portfolio
- October 5, 2011 – Obama administration recognizes B2H as one of seven national priority projects that when built, will help increase electric reliability, integrate new renewable energy into the grid, create jobs and save consumers money. See news release.
- November 2011 – Idaho Power completes a Revised Plan of Development for B2H
- January 12, 2012 – Idaho Power, BPA and PacifiCorp enter into Joint Permit Funding Agreement
- March 2, 2012 – ODOE issues a Project Order for B2H

- June 2012 – Idaho Power completes a Supplemental Siting Study for B2H
- October 2, 2012 – BPA identifies B2H as the best option for meeting load growth in southeastern Idaho
- November 27, 2012 – Idaho Power receives formal capacity rating from Western Electricity Coordinating Council (WECC)
- February 28, 2013 – Idaho Power submits Preliminary Application for Site Certificate to Oregon Department of Energy
- June 28, 2013 – Idaho Power files the 2013 IRP
- December 19, 2014 – Draft EIS and Land-use Plan Amendments Published in Federal Register
- December 22, 2014 – ODOE issues amended Project Order for B2H
- June 22, 2015 – Idaho Power submits easement application to Navy to site on Naval Weapons System Training Facility Boardman (aka "Bombing Range")
- June 30, 2015 – Idaho Power files the 2015 IRP – B2H Project identified in the preferred resource portfolio
- November 25, 2016 – BLM issues the Final EIS for B2H
- November 18, 2016 – Idaho Power submits revised application to Navy, updating the route on Navy property based on collaborative routing solution
- January 20, 2017 – Donald Trump inaugurated as 45th President of the United State
- June 29, 2017 – Idaho Power submits electronic version of Amended Preliminary Application for Site Certification to ODOE
- June 30, 2017 – Idaho Power files the 2017 Integrated Resource Plan (IRP) – B2H Project identified in the preferred resource portfolio
- July 19, 2017 – Idaho Power submits hard copies of the Amended Preliminary Application for Site Certification to ODOE.
- November 17, 2017 – The BLM issues a Record of Decision (ROD) for the B2H project. The Record of Decision was signed by the Assistant Secretary of Lands and Minerals, U.S. Department of Interior.

- January 9, 2018 – BLM and Idaho Power sign the BLM ROW Grant for the B2H project.
- September 21, 2018 – ODOE determines the B2H Application for Site Certificate is complete.
- September 28, 2018 – Idaho Power files the Application for Site Certificate with ODOE.
- November 13, 2018 – The U.S. Forest Service issues a Record of Decision for the B2H project
- May 22, 2019 – The Oregon Department of Energy issues a Draft Proposed Order.
- May 28, 2019 – The U.S. Forest Service and Idaho Power sign a ROW easement agreement for the B2H project.
- May 29, 2019 – Bonneville Power Administration issues a Record of Decision for moving an existing 69 kV line from the U.S. Navy bombing range to accommodate the B2H project.
- September 2019 – U.S. Navy issues a Record of Decision for 7.1 miles of project on U.S. Navy Naval Weapons Training Facility Boardman, Oregon.