IDAHO POWER®

IRP

INTEGRATED RESOURCE PLAN

2025

June 2025

SAFE HARBOR STATEMENT

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GLOSSARY OF ACRONYMS

A/C—Air Conditioning

AEG—Applied Energy Group

AFUDC—Allowance for Funds Used During Construction

akW—Average Kilowatt

aMW—Average Megawatt

ATC—Available Transfer Capacity

B2H—Boardman to Hemingway

BAA—Balancing Authority Area

BESS—Battery Energy Storage System

BLM—Bureau of Land Management

BPA—Bonneville Power Administration

Bridger—Jim Bridger Power Plant

CAISO—California Independent System Operator

CCCT—Combined-Cycle Combustion Turbine

CCS—Carbon Capture and Sequestration

CEYW—Clean Energy Your Way

cfs—Cubic Feet per Second

CO2—Carbon Dioxide

CPCN—Certificate of Public Convenience and Necessity

CSPP—Cogeneration and Small-Power Production

CWA—Clean Water Act of 1972

DOE—Department of Energy

DPO—Draft Proposed Order

DR—Demand Response

DSM—Demand-Side Management

DSP—Distribution System Planning

EDAM—Extended Day Ahead Market

EE—Energy Efficiency

EFSC—Energy Facility Siting Council

EIA—Energy Information Administration

EIM—Energy Imbalance Market

EIS—Environmental Impact Statement

ELCC—Effective Load Carrying Capability

ELR—Energy-Limited Resource

EPA—Environmental Protection Agency

ESA—Energy Service Agreement

ESPA—Eastern Snake River Plain Aquifer

ESPAM—Eastern Snake Plain Aquifer Model

FCRPS—Federal Columbia River Power System

FERC—Federal Energy Regulatory Commission

FIP–Federal Implementation Plan

FPA—Federal Power Act of 1920

GBT—Great Basin Transmission

GHG—Greenhouse Gas

H2—Hydrogen

HB—House Bill

HCC—Hells Canyon Complex

INL—Idaho National Laboratory

IPUC—Idaho Public Utilities Commission

IRA—Inflation Reduction Act of 2022

IRP—Integrated Resource Plan

IRPAC—IRP Advisory Council

ISEA—Idaho Strategic Energy Alliance

ITC—Investment Tax Credit

IWRB—Idaho Water Resource Board

kV—Kilovolt

kW—Kilowatt

kWh—Kilowatt-Hour

LCOC—Levelized Cost of Capacity

Li-ion—Lithium Ion

LiDAR—Light Detection and Ranging

LOLE—Loss of Load Expectation

LTCE—Long-Term Capacity Expansion

Markets+—Southwest Power Pool’s Markets+

MMBtu—Million British Thermal Units

MSA—Metropolitan Statistical Area

MW—Megawatt

MWh—Megawatt-Hour

NEPA—National Environmental Policy Act of 1969

NOx—Nitrogen Oxide

NPV—Net Present Value

OATT–Open-Access Transmission Tariff

O&M—Operations and Maintenance

ODOE—Oregon Department of Energy

OPUC—Public Utility Commission of Oregon

PCA—Power Cost Adjustment

PPA—Power Purchase Agreement

PRB–Power River Basin

PRM—Planning Reserve Margin

PTC—Production Tax Credit

PURPA—Public Utility Regulatory Policies Act of 1978

PV—Photovoltaic

QF—Qualifying Facility

RCAT—Reliability and Capacity Assessment Tool

REC—Renewable Energy Certificate

RFP—Request for Proposal

ROD—Record of Decision

ROR—Run-of-River

RPS—Renewable Portfolio Standard

SCCT—Simple-Cycle Combustion Turbine

SCR—Selective Catalytic Reduction

SIP—State Implementation Plan

SMR—Small Modular Reactor

SWIP-N—Southwest Intertie Project-North

T&D—Transmission and Distribution

TRC—Total Resource Cost

TUA–Transmission Use and Capacity Exchange Agreement

UCT—Utility Cost Test

VER—Variable Energy Resource

WECC—Western Electricity Coordinating Council

WMP—Wildfire Mitigation Plan

WPP—Western Power Pool

WRAP—Western Resource Adequacy Program

EXECUTIVE SUMMARY

Introduction

The 2025 Integrated Resource Plan (IRP) is Idaho Power's 17th 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).

The 2025 IRP evaluates the 20-year planning period from 2026 through 2045. During this period, Idaho Power's demand for electricity is expected to grow significantly. Over the 20-year forecast period, the company's peak load is expected to grow by approximately 1,700 megawatts (MW) with nearly 1,000 MW in the next five years alone. Continued customer growth is driving demand, and the average annual number of metered customers is expected to increase from the December 2024 level of nearly 648,000 to 867,000 in 2045.

To meet this growing demand, the 20-year IRP includes the addition of large quantities of cost-effective resources: 1,445 MW of solar, 885 MW of battery storage, 700 MW of wind, 611 MW of converted coal to gas, 550 MW of new gas, 344 MW of energy efficiency, and 20 MW of incremental demand response.

Idaho Power's IRP analysis has shown consistent need for transmission dating back to 2009 and the 2025 IRP again includes transmission as a cost-effective way to facilitate regional energy exchange and provide capacity and energy for Idaho Power customers. Specifically, the IRP includes the Boardman to Hemingway (B2H) 500 kilovolt (kV) transmission line in December 2027 to connect the Pacific Northwest and Idaho, the Southwest Intertie Project North (SWIP-N) a 500 kV line between Idaho and Nevada, with connectivity to the Las Vegas area in 2028, and the Midpoint–Hemingway #2 500 kV line (Gateway West segment 8) added in two phases, with phase one, Hemingway–Mayfield 500 kV, in 2028 and phase two, Mayfield–Midpoint 500 kV, in 2030.

The IRP is a 20-year plan, prepared biennially, which has historically allowed Idaho Power to timely update its long-term resource plan based on changing circumstances. However, balancing load and resources has become increasingly more dynamic as major planning inputs and assumptions are subject to change in real-time. These long-term planning challenges are not unique to Idaho Power; however, several uncertainties in this planning cycle are specific to Idaho Power. Due to the increased level of uncertainty surrounding several important near-term decisions, the 2025 IRP has been prepared in a manner intended to provide the flexibility and adaptability necessary to inform decisions as more information becomes known before the next planning cycle. Two examples include load growth and the Environmental Protection Agency

(EPA) rule 111(d). These, and other planning scenarios, are discussed in greater detail throughout this planning document.

IRP Methodology Improvements

The primary goal of the long-term resource planning process is to ensure Idaho Power's system has sufficient resources to reliably serve customer demand and flexible capacity needs. In each IRP, the company models resource needs over a 20-year planning period with the primary objective of minimizing costs and risks to customers.

As in prior planning cycles, Idaho Power used Energy Exemplar's Aurora model for the 2025 IRP. Using Aurora's Long-Term Capacity Expansion (LTCE) modeling tool, resources are selected from a variety of supply- and demand-side resource options to develop portfolios that are least-cost for a variety of alternative future scenarios while meeting reliability criteria. The model can also select an exit from or a conversion to natural gas for existing coal generation units, as well as build resources based on economics absent a defined capacity need. The LTCE modeling process is discussed in further detail in Chapter 9. Portfolios. A discussion of the developed portfolios and results can be found in Chapter 10. Modeling Analysis.

To ensure Aurora develops least-cost, reasonable, and defensible portfolios, Idaho Power performed validation and verification tests to confirm the model is operating as expected and producing the most economic portfolio under numerous variations of resources and timing. Details about the validation and verification process can be found in Chapter 9.

To verify that Aurora-built resource portfolios meet Idaho Power's reliability requirements, the company continued to leverage the Loss of Load Expectation (LOLE) methodology and calculated annual capacity positions to meet a LOLE threshold of 0.1 event-days per year. An in-depth discussion of the LOLE calculation process can be found in the System Reliability Modeling—Methodology section of *Appendix D—System Reliability and Regulating Reserves*.

For each portfolio, Idaho Power modeled costs and benefits including:

- Construction costs
- Fuel costs
- Operations and Maintenance (O&M) costs
- Transmission upgrade costs associated with interconnecting new resource options
- Natural gas pipeline reservation and new natural gas pipeline infrastructure costs
- Projected wholesale market purchases and sales
- Anticipated environmental controls

- Market value of Renewable Energy Certificates (REC) for REC-eligible resources
- Investment/Production Tax Credits (ITC/PTC) associated with qualifying generation

Additionally, to enhance the risk evaluation within the 2025 IRP, the company worked with the IRP Advisory Council (IRPAC) to develop a variety of scenarios that build portfolios based on several hypothetical versions of the future. Some of the hypothetical futures align with Idaho Power's near- and long-term objectives, making the associated scenario portfolios a good point of comparison to the final Preferred Portfolio. Specifically, the company used the scenario results to confirm that decisions identified in the Near-Term Action Plan window (2026–2030) are robust and reliable across different futures. The future scenarios developed with IRPAC include:

- With and Without EPA Rule 111(d)
- With and Without SWIP-N
- High Prices: High natural gas price and a price on carbon emissions
- Low Prices: Low natural gas price
- 100% Clean by 2045: All electricity resources must be clean (non-carbon emitting) by 2045
- Additional Large Load: High customer growth scenario
- No Replacement PURPA[1] Contracts: Assumes existing PURPA contracts do not renew and that no new PURPA projects are developed
- Extreme Weather: Assumes more frequent extreme weather that increases demand for electricity and reduces hydro generation
- Load Shift: Assumes a shift of demand for electricity from 6:00 pm to 10:00 pm to 10:00 am to 2:00 pm in summer months

Portfolio Analysis Overview

The Aurora model selects resources based on set criteria—primarily, resources that most cost-effectively meet future demand for electricity *and* maintain Idaho Power's reliability criteria. Generally, resources in the model are "selectable," meaning the model can pick a given resource—such as adding solar or batteries—if doing so will help achieve the objective of building the lowest-cost, reliable portfolio. Conversely, the model can choose *not* to select

[1] *Public Utility Regulatory Policies Act of 1978* (PURPA)

resources if doing so will lead to higher costs or an unreliable portfolio that doesn't meet demand requirements.

Ultimately, the best portfolio—the one that meets all demand and reliability criteria—at the best combination of least cost and least risk is selected as the Preferred Portfolio. Put simply, the Preferred Portfolio is the best and most affordable path to meet the needs of Idaho Power's customers for the next 20 years, based on information known today.

For the 2025 IRP, Idaho Power identified several key branches to evaluate in additional detail, and the company required the model to build portfolios both with and without these branches. These with and without views help Idaho Power and interested parties understand the impacts of major decision points. The main with and without scenario in this IRP analysis is the EPA Rule 111(d).

Portfolios were compared against each other to determine which portfolios could be eliminated from contention, and where to focus additional portfolio robustness testing.

To validate the resource selection and robustness of the Preferred Portfolio, the company performed additional scenario and sensitivity analyses, including the following:

- The resources selected in the Near-Term Action Plan window of the Preferred Portfolio were compared to optimal resources selected for alternative future scenarios, identified in conjunction with IRPAC, to determine the changes that would need to be made in each of those scenarios.
- Validation and verification studies were performed to test Bridger units 3 & 4 options, and both supply-side and demand-side resources.

2025 Preferred Portfolio

Idaho Power's selected Preferred Portfolio for the 2025 IRP includes a diverse mix of generation resources, storage systems, and transmission lines. Specifically, the Preferred Portfolio adds 1,445 MW of solar, 885 MW of storage (4-hour batteries, as well as 50 MW of long duration 100-hour storage), 700 MW of wind, 550 MW of natural gas, 344 MW of incremental energy efficiency (EE), and 20 MW of incremental demand response (DR). Additionally, the Preferred Portfolio includes conversions of multiple coal-fired generation units to natural gas and adds a net total of 611 MW of natural gas via coal conversions through 2045. In total, the Preferred Portfolio—considering both additions and exits—adds 4,071 MW of resource capacity over the next 20 years. To support these resource additions, the Preferred Portfolio also includes the B2H transmission line beginning in December 2027, SWIP-N transmission line beginning in November 2028, and the Midpoint–Hemingway #2 500 kV (Gateway West segment 8) in two phases with the first phase in 2028 and the second phase in 2030.

Table 1.1 shows the resource additions, coal exits, as well as new transmission that make up Idaho Power's 2025 IRP Preferred Portfolio.

Table 1.1 Preferred Portfolio additions and coal exits (MW)

Preferred Portfolio (MW)											
Year	Coal Exits	Conv. Gas	New Gas	Wind	Solar	4Hr	100Hr	Trans.	DR	EE Forecast	EE Bundles
2026	-134	261	0	0	125	250	0	0	0	18	0
2027	0	0	0	600	420	100	0	0	0	14	0
2028	0	0	0	0	100	200	0	B2H	0	15	0
2029	0	0	150	100	0	155	0	SWIP-N	10	16	0
2030	-350	350	300	0	100	0	0	0	0	16	0
2031	0	0	0	0	400	0	0	0	0	17	8
2032	0	0	0	0	200	0	0	0	0	17	0
2033	0	0	0	0	100	50	0	0	0	17	21
2034	0	0	0	0	0	0	0	0	0	16	6
2035	0	0	0	0	0	0	0	0	0	16	5
2036	0	0	0	0	0	0	0	0	0	16	5
2037	0	0	0	0	0	0	0	0	0	15	0
2038	0	0	0	0	0	0	0	0	0	14	0
2039	0	0	0	0	0	0	0	0	0	13	0
2040	0	0	0	0	0	5	0	0	0	12	0
2041	0	0	50	0	0	5	0	0	0	12	0
2042	0	0	0	0	0	5	0	0	10	11	3
2043	0	0	50	0	0	5	0	0	0	11	0
2044	0	0	0	0	0	55	0	0	0	11	7
2045	0	0	0	0	0	5	50	0	0	8	2
Sub Total[2]	-484	611	550	700	1,445	835	50		20	287	58
Total	**4,071**	**Portfolio Cost: $10,965M**									

The Near-Term Action Plan for the 2025 IRP reflects near-term actionable items of the Preferred Portfolio. The Near-Term Action Plan identifies key milestones to successfully position Idaho Power to provide reliable, economic, and environmentally sound service to customers into the future. The current regional electric market, regulatory environment, pace of technological change, rapid load growth, and Idaho Power's goal of 100% clean energy by 2045 make the 2025 Near-Term Action Plan especially relevant.

[2] Subtotal and annual increments in the table do not show the base forecast associated with forecasted new PURPA and PURPA contract renegotiations. For this information, refer to *Appendix C—Technical Report*.

The Near-Term Action Plan associated with the Preferred Portfolio is driven by its core resource actions through 2030. These core resource actions include some actions to which the company had committed prior to the development of the 2025 IRP and some that were identified because of the 2025 IRP analysis:

Actions Committed to before the 2025 IRP–Not for Regulatory Acknowledgment

- Conversion of Valmy units 1 and 2 from coal to natural gas by summer 2026 (conversions scheduled to occur by summer of 2026)
- 80 MW of additional cost-effective EE between 2026 and 2030 (added EE identified in Idaho Power's 2024 energy efficiency potential study)
- 125 MW of solar added in 2026 (executed contract for Clean Energy Your Way (CEYW) customer resource)
- 250 MW of four-hour storage added in 2026 (resources selected from the 2026 Request for Proposal [RFP])
- 600 MW of wind added in 2027 (resources selected from the 2026 RFP)
- 100 MW of solar + storage added in 2027 (resources selected from the 2026 RFP)
- 320 MW of solar added in 2027 (executed contract for CEYW customer resource)
- B2H online by year end 2027
- Issue a 2028 All-Source RFP to procure resources to come online in 2028 and beyond (UM 2317)

2025 IRP Decisions for Acknowledgment

- SWIP-N online by November 2028
- Pursue cost-effective existing DR program expansion by 10 MW
- Coordinate with PacifiCorp on the future of Bridger units 3 & 4 given the company's identified need for capacity and energy from Bridger units 3 & 4
- Pursue generation resources in 2029 and 2030 to meet forecasted needs, identified in the preferred portfolio as natural gas, wind, solar, and storage
- The Near-Term 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 the Preferred Portfolio is included in this chapter. A chronological listing of the near-term actions follows in Table 1.2.

Table 1.2 Near-Term Action Plan (2026–2030)

Year	Action	Requesting Acknowledgement
Summer 2026	Convert Valmy units 1 and 2 from coal to natural gas	No
2026	125 MW of solar added in 2026 (executed contract for CEYW customer resource)	No
2026	250 MW of four-hour storage added in 2026 (resources selected from the 2026 RFP)	No
2027	600 MW of wind added in 2027 (resources selected from the 2026 RFP)	No
2027	100 MW of solar + storage added in 2027 (resources selected from the 2026 RFP)	No
2027	320 MW of solar added in 2027 (executed contract for CEYW customer resource)	No
2027	B2H online by year end 2027	No
2028	Issue a 2028 RFP to procure resources to come online in 2028 and beyond (UM 2317)	No
2028	SWIP-N online by November 2028	Yes
2026–2028	80 MW of additional cost-effective EE between 2026 and 2030 (added EE identified in Idaho Power's 2024 energy efficiency potential study)	No
2029	Pursue cost-effective existing DR program expansion by 10 MW	Yes
2026–2030	Coordinate with PacifiCorp on the future of Bridger units 3 & 4 given the company's identified need for capacity and energy from Bridger units 3 & 4	Yes
2029–2030	Pursue generation resources in 2029 and 2030 to meet forecasted needs, identified in the preferred portfolio as natural gas, wind, solar, and storage	Yes

Bridger Unit Conversions

Idaho Power owns one-third of Bridger units 1–4, and PacifiCorp owns the remaining two-thirds and is the plant operator. In its 2025 IRP, PacifiCorp concluded it would be cost-effective to install carbon capture and sequestration on Bridger units 3 & 4 in 2030 and operate as a coal plant through 2042 and then retire. Idaho Power has identified a gas conversion of Bridger units 3 & 4 in 2030 and operations through the end of the planning timeframe. Based on these differences, the companies will work together to determine the future of Bridger units 3 & 4.

The EPA recently revised 111(d) rule, and its future status, is a major consideration for Bridger units 3 & 4. Assuming the revised 111(d) rule is in place, as in the Preferred Portfolio, the natural gas conversion is the cost-effective choice for Idaho Power. Should the 111(d) rule be reverted, additional analysis will be required between a natural gas conversion and a Powder River Basin coal conversion due to comparable portfolio costs. Regardless of the outcome on the 111(d) rule, Idaho Power continues to see the need for these units in its plan.

Need for Flexible Resources

Idaho Power is expected to go through a period of unprecedented demand growth in the next several years. This demand growth is predominantly from customers whose load is flat both seasonally and diurnally. The analysis and testing in this IRP show the need for the combination of firm, flexible resources like new natural gas, the buildout of interregional transmission like B2H and SWIP-N, and continued investment in renewable and storage resources consistent with recent procurement activities.

Need for Flexibility in Selection of the Preferred Portfolio

In the 2025 IRP, Idaho Power finds itself in an era of heightened uncertainty where numerous probable events could occur that would materially change the resources selected in the near-term action plan. Specifically, Idaho Power is focused on the real possibility for additional large load customers and changes in federal and state policy. On the large load customer front, Idaho Power continues to have significant interest from potential industrial customers. As such, the 2025 IRP studies multiple additional large load scenarios with both 300 MW and 500 MW cases. For policy consideration, significant uncertainty exists around the eventual fate of the recent changes to the 111(d) rule regarding carbon emissions for existing and new resources. To better anticipate either of these major factors changing in the near term, the 2025 IRP studies both large load and 111(d) rule reversion and the combinations thereof. As such, although the 2025 IRP identifies the *With 111(d) Bridger 3 & 4 NG* as the Preferred Portfolio, it is possible that before or after acknowledgment Idaho Power may change its selection to better reflect the realities at the time.

1. BACKGROUND

Integrated Resource Plan

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 and risk while also considering environmental factors.
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 Integrated Resource Plan (IRP) evaluates a 20-year planning period in which demand is forecasted and additional resource requirements are identified.

Idaho Power relies on existing resources, including hydroelectric projects, solar photovoltaic (PV) projects, wind farms, battery energy storage systems (BESS), geothermal plants, natural gas-plants, coal-facilities, and energy markets via transmission interconnections. The company's existing supply-side resources are detailed in Chapter 4, while potential future supply-side resources are explored in Chapter 5.

Other resources include demand-side management (DSM) and transmission resources, which are further explored in chapters 6 and 7, respectively. The goal of DSM programs is to achieve cost-effective energy efficiency savings and provide an optimal amount of peak reduction from demand response (DR) 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 by implementing and carefully managing incentive programs as well as through outreach and education.

Idaho Power's resource planning process evaluates additional stand-alone transmission capacity as a resource option to serve retail customers. Transmission projects are often regional resources, and Idaho Power coordinates transmission planning as a member of NorthernGrid. 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 and Idaho Power retail customers. The delivery of energy, both within Idaho Power's system and through regional transmission interconnections, is of increasing importance for several reasons. First, adequate transmission is essential to achieve cost savings benefits through robust participation in the energy markets. Second, it is beneficial to unlock geographic load and resource diversity across the western interconnection. 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 IRP Advisory Council (IRPAC) meets regularly during the development of the resource plan, and the meetings are open to the public. Members of the council include staff from the Idaho Public Utilities Commission (IPUC) and Public Utility Commission of Oregon (OPUC); political, environmental, and customer representatives; and representatives of other public-interest groups. Many members of the public also participate in the IRPAC meetings. Some individuals have participated in Idaho Power's resource planning process for over 20 years. A list of the 2025 IRPAC members can be found in *Appendix C—Technical Report*.

Idaho Power facilitated several IRPAC meetings (see *Appendix C—Technical Report*, IRPAC Meeting Schedule and Agenda). Except for the introductory meeting, all 2025 IRPAC meetings were conducted virtually, which resulted in increased and more diverse participation of members and the general public.

To further enhance engagement, Idaho Power also maintained a webpage for stakeholders to submit requests for information and for Idaho Power to provide responses. The webpage allowed stakeholders to develop their understanding of the IRP process, particularly its key inputs, consequently enabling more meaningful stakeholder involvement. The company made presentation slides and other materials used at the IRPAC meetings, in addition to the question-submission portal and other IRP documents, available to the public on its website at idahopower.com/IRP. As an established part of the IRP process, Idaho Power included educational resources provided and prepared to help IRPAC members and attendees understand and catch up on industry concepts on its IRP webpage (accessed at the prior link). These resources include information on industry topics and pre-recorded presentations prepared by the National Renewable Energy Laboratory, the United States Energy Information Administration (EIA), the U.S. Department of Energy (DOE), and Idaho Power. A list of acronyms and a directory of Idaho Power employees involved in the process was also posted.

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 while also minimizing costs and risks to customers. This process is completed, and a new plan is produced every two years. To ensure Idaho Power can meet customers' growing need for energy, the capability of the existing system is included and then resources are added (or removed). Multiple portfolios consisting of varying resource additions (and exits) are produced. The portfolios are tested to ensure they meet the company's system needs and then compared, and the portfolio that best minimizes cost and risk is selected as the preferred portfolio.

Cost

Costs for each portfolio include the capital costs of designing and constructing each resource, including transmission builds and expansions, through the 20-year timeframe of the plan. Operational costs—such as fuel costs, maintenance costs, environmental controls, and the price to purchase and sell energy on the power market—are modeled using planning conditions to compare the cost effectiveness of each portfolio.

Risk

Typical of long-term planning, uncertainty increases the further into the future one attempts to evaluate. Acknowledging this uncertainty and the risk this creates, the 2025 IRP includes a robust risk analysis and approaches the subject in three ways.

First, to enhance the risk evaluation within the 2025 IRP, the company, with input from the IRPAC, developed a variety of unique future scenarios. The company ultimately used these scenarios to test whether the decisions being made within the Near-Term Action Plan window are robust across multiple futures.

The second method employed by the 2025 IRP is an analysis of stochastic risk. Stochastic analyses help quantify the sensitivity and risk associated with variables over which Idaho Power has little or no control. For more information, see Chapter 10.

The third method of risk analysis, qualitative risk, is used to identify risks that are not easily quantified. A discussion of qualitative risk can also be found in Chapter 10.

Modeling

Due to the complexity involved in an analysis that includes a 20-year forecast for energy demand, fuel prices, resource costs and more, Idaho Power uses modeling software to generate and optimize resources selected in portfolios. For the 2025 IRP, the company used Aurora's Long-Term Capacity Expansion (LTCE) platform to generate resource portfolios. As described in Chapter 9. Portfolios, the software evaluates how to cost-effectively meet future needs by selecting resources that are economically and operationally optimized within modeling constraints.

Validation and Verification

In the 2025 IRP, the company employed additional verification tests to ensure the Aurora LTCE model produced an optimized solution within its modeling tolerance. Verification tests validated the most economic portfolio under numerous variations of resources and timing.

Details about the validation and verification process can be found in the Validation and Verification section of *Appendix C—Technical Report*.

System Reliability

The company used the LOLE methodology to verify that all portfolios meet Idaho Power's system reliability requirements. Idaho Power implements the LOLE methodology through the internally developed Reliability and Capacity Assessment Tool (RCAT), which uses the portfolio resource buildouts and calculates the annual capacity positions to meet the LOLE threshold of 0.1 event-days per year. Portfolios meet Idaho Power's reliability threshold when all years of the plan are in a position of capacity length.

An in-depth discussion of how the LOLE methodology supports the portfolio development process can be found in the System Reliability Modeling—Portfolio Analysis section of *Appendix D—System Reliability and Regulating Reserves*.

Energy Risk Management Policy

While the 2025 IRP addresses Idaho Power's long-term resource needs, near-term energy needs are evaluated in accordance with the company's *Energy Risk Management Policy* and *Energy Risk Management Standards*. The 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 risk management standards specify an 18-month load and resource review period, and Idaho Power's Risk Management Committee assesses the resulting operations plan monthly.

2. POLITICAL, REGULATORY, AND OPERATIONAL CONSIDERATIONS

As a regulated utility, Idaho Power's operations and long-term planning are guided by federal, regional, and state policies and requirements. This chapter addresses long-standing and new federal policies, Idaho- and Oregon-specific policies and regulations, and new developments in regional energy policy.

Federal Policy & Activities

Hydroelectric Relicensing

As a utility that operates non-federal hydroelectric projects on qualified waterways, Idaho Power obtains licenses from FERC for its hydroelectric projects. The licenses are valid for 30 to 50 years, depending on the size, complexity, and cost of the project.

Hells Canyon Dam

Idaho Power is currently relicensing two projects: the Hells Canyon Complex (HCC) and American Falls. The HCC is the more significant of the two relicensing efforts.

The HCC provides approximately 70% of Idaho Power's hydroelectric generating capacity. 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 variable energy resources (VER).

Idaho Power's 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*; 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, Idaho and Oregon issued the final CWA 401 certification on May 24, 2019.

In 2020, Idaho Power submitted its supplement to the final license application to FERC. In addition, the company filed draft biological assessments to FERC, U.S. Fish and Wildlife

Service, and the National Marine Fisheries Service under section 7 of the *Endangered Species Act*. In April 2025, FERC issued an updated schedule for the supplemental EIS, indicating the draft and final supplemental EIS would be issued no later than September 2025 and May 2026, respectively. 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 packages are still being conducted—Idaho Power cannot determine the ultimate terms of, and costs associated with, any resulting long-term license.

In addition to the relicensing of the HCC, Idaho Power is also relicensing its American Falls Hydroelectric Project. Idaho Power owns the generation facility but not the structural dam or reservoir, which are owned by the U.S. Bureau of Reclamation. Idaho Power filed the final relicensing application with FERC in February 2023. In September 2023, Idaho Power filed an application for CWA Section 401 water quality certification with IDEQ. In September 2024, IDEQ issued a final CWA Section 401 water quality certification. FERC released its environmental assessment on January 16, 2025.

Relicensing activities included the following:

- Coordinating the relicensing process
- Consulting with regulatory agencies, tribes, and interested parties on resource and legal matters
- Preparing and conducting studies or analyses on fish, endangered species, terrestrial resources, water quality, recreation, and archaeological resources, among others
- Analyzing data and reporting study results
- 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 protection, mitigation, and enhancement 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.

The 2025 IRP assumes that the available capacity and operational flexibility of the HCC and American Falls will be consistent with the most current relicensing proposals and Idaho Power's anticipation of what will be included in a future FERC license. All other hydroelectric facilities are assumed to have available capacity and operational flexibility as outlined in their current FERC licenses.

Recent Executive Orders

Since the start of the current presidential administration in January 2025, the administration has released several executive orders that may impact Idaho Power.[3] [4] [5] [6] [7] These executive orders include, but are not limited to, orders regarding tariffs, the electric grid, the coal industry, government workforce and staffing, revocation of executive orders of prior presidential administrations, and other orders intended to regulate international trade, strengthen the U.S. energy industry, and/or promote deregulation, including with respect to environmental and energy-related regulations. The outcome of these executive orders and U.S. federal agencies' review of regulations covered by executive orders is difficult to predict.

While this administration's policy preferences appear to mark a shift in federal energy and environmental policy, there are still many changing targets. Most of these stated policy goals require either congressional or agency action, which have yet to occur. The company is actively monitoring the current administration policy shifts and their potential impacts; however, the company's 2025 IRP analysis adheres to current rules and requirements, which do not always reflect the stated policy goals of the new administration.

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[3] Declaring a National Energy Emergency, retrieved April 2025: whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/

[4] Putting America First in International Environmental Agreements, retrieved April 2025: whitehouse.gov/presidential-actions/2025/01/putting-america-first-in-international-environmental-agreements/

[5] Unleashing American Energy, retrieved April 2025: whitehouse.gov/presidential-actions/2025/01/unleashing-american-energy/

[6] Temporary Withdrawal of All Areas on the Outer Continental Shelf from Offshore Wind Leasing and Review of the Federal Government's Leasing and Permitting Practices for Wind Projects, retrieved April 2025: whitehouse.gov/presidential-actions/2025/01/temporary-withdrawal-of-all-areas-on-the-outer-continental-shelf-from-offshore-wind-leasing-and-review-of-the-federal-governments-leasing-and-permitting-practices-for-wind-projects/

[7] Initial Rescissions of Harmful Executive Orders and Actions, retrieved April 2025: whitehouse.gov/presidential-actions/2025/01/initial-rescissions-of-harmful-executive-orders-and-actions/

Inflation Reduction Act

In August 2022, the *Inflation Reduction Act of 2022* (IRA) was signed into law to boost domestic energy production by expanding clean energy incentives. The law allocates hundreds of billions of dollars for energy and climate initiatives, primarily by broadening the availability of tax credits for clean energy investment and production.

Key provisions include an extended investment tax credit (ITC) for solar projects, a new ITC for standalone storage projects, and technology-neutral investment and production tax credits (PTC) for new clean electricity generation with zero or negative greenhouse gas (GHG) emissions. The IRA also includes an expansion of the 45Q carbon capture and sequestration (CCS) tax credits.

The incentives vary in amount, duration, and eligibility, with potential “bonus” credits for projects that support domestic manufacturing or serve low-income communities. Based on recent executive orders and draft budget reconciliation proposals, these incentives may change to reflect the new Trump administration’s policy objectives.

Power Plant Emissions Regulations

In April 2024, the EPA released a final rule under Section 111 of the *Clean Air Act of 1970* (111(d) Rule) that regulates CO_2 emissions from existing coal and natural gas electric generating units. Under the final rule, applicable standards of emission reduction vary based upon the retirement date of coal units and the capacity factor of existing and new natural gas units. Section 111(d) refers to existing resources while 111(b) refers to new resources. Throughout this IRP, both sections are implied using 111(d).

While there are ongoing legal challenges to these new regulations, they are currently the law. Based on recent executive orders, these regulations may change to reflect the new Trump administration's policy objectives.

Cross-State Air Pollution Rule

The Good Neighbor Plan is intended to address 23 states’ obligations to eliminate their contribution to nonattainment, or interference with maintenance, of the 2015 ozone National Ambient Air Quality Standards under the “good neighbor” or “interstate transport” provision of the *Clean Air Act*. Several states challenged EPA’s final action on the Good Neighbor Plan in the D.C. Circuit Court and requested a stay in the U.S. Supreme Court. On June 27, 2024 the U.S. Supreme Court issued its opinion in *Ohio v. EPA* granting an application to stay EPA’s Federal Implementation Plan (FIP). The company will monitor for future Nitrogen Oxide (NOx)-related emissions rules and constraints.

Wyoming Regional Haze Compliance

On February 14, 2022, Wyoming and PacifiCorp filed a Consent Decree in the Wyoming State District Court, settling potential State compliance claims with the State Implementation Plan (SIP) previously approved for the Jim Bridger Power Plant (Bridger) by the EPA in 2015. The Consent Decree required PacifiCorp to submit a new permit application and a proposed SIP revision within two months, reflecting heat input limits consistent with the conversion of Bridger units 1 and 2 to natural gas generation by January 1, 2024. In April 2022, PacifiCorp submitted the new permit application and proposed SIP revision, consistent with the terms of the Consent Decree. In 2024, the EPA partially approved and partially disapproved the proposed SIP revision. However, on May 1, 2025, EPA granted the company's request for reconsideration of the proposed SIP revision.

The 2025 IRP modeling considers the monthly heat input limits of the Consent Decree.

Public Utility Regulatory Policies Act

In 1978, the United States Congress passed PURPA, requiring investor-owned electric utilities to purchase generation from any qualifying facility (QF) that delivers generation to the utility. A QF is defined by FERC as a small renewable-generation project or small cogeneration project. Electricity from Cogeneration and Small-Power Production (CSPP) is often associated with PURPA. Individual states were tasked with establishing Power Purchase Agreement (PPA) terms and conditions, including prices 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 delivered to Idaho, and to OPUC rules and regulations for all PURPA facilities delivered to 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 that, 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 Idaho Power's Tariff Schedule 73; and for Oregon QFs, Schedule 85. QFs also have the option to sell energy "as-available" under Idaho Power's Tariff Schedule 86.

Idaho Policy & Activities

Idaho Strategic Energy Alliance

Under the umbrella of the Idaho Governor's Office of Energy and Mineral Resources, the Idaho Strategic Energy Alliance (ISEA) helps 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.

ISEA's strategy focuses 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.

Idaho Power representatives serve on the ISEA Board of Directors and several volunteer task forces.

Idaho Energy Landscape

In 2025, the ISEA prepared the *2025 Idaho Energy and Mineral Landscape Report* to help Idahoans better understand the contemporary energy landscape in the state and to make informed decisions about Idaho's energy future. The report concludes, "Idaho's abundant natural resources enable reliable and low-cost energy which sustains Idaho's quality of life for its citizens and the economy."[8] The report provides information about energy resources, production, distribution, and use in the state.

Idaho Water Considerations

Power generation at Idaho Power's hydroelectric projects on the Snake River and its tributaries is dependent on the management of water resources by local, state, and federal entities, and the administration of water rights by the states within the Snake River Basin. In addition to a FERC license and other associated state and federal permits, Idaho Power must also secure and maintain state water rights for the operation of these projects.

Idaho Power's Swan Falls Dam was built in 1901 and is the oldest hydroelectric project on the Snake River.

The long-term sustainability of Snake River Basin streamflows, including tributary spring flows and the regional aquifer system, is crucial for Idaho Power to maintain generation from these

[8] 2022-Idaho-Energy-FINAL.pdf. Accessed July 2023.

projects. Idaho Power is dedicated to the vigorous defense of its water rights. The company's ongoing participation in various efforts to develop sustainable water-rights related policy and studies is intended to guarantee sufficient water is available for use at the company's hydroelectric projects in the Snake River Basin and to ensure the state's acknowledgment of the value of hydroelectric power to Idaho's economy.

The Swan Falls Agreement, which was entered into by Idaho Power and the governor and attorney general of the State of Idaho in October 1984, resolved a struggle over the company's water rights at the Swan Falls Hydroelectric 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 retains the right to use water more than the minimum flows at its facilities for hydroelectric generation.

In 2007, Idaho Power asked the court to determine whether the agreement subordinated Idaho Power's hydroelectric water rights to managed 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 managed 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. Pursuant to the Framework, Idaho Power, the Idaho Water Resource Board (IWRB), and the State of Idaho work cooperatively to explore resolution of issues as members of the Swan Falls Implementation Group.

In 2014, Idaho Power expanded its long-standing cloud-seeding program, which began in the Payette basin in 2003. The expansion of cloud-seeding activities to the Boise and Wood River basins was conducted in collaboration with basin water users and the IWRB. Along with augmenting surface flows in the Snake River basins, cloud seeding in the Wood River Basin, along with the Upper Snake River Basin, benefits the Eastern Snake River Plain Aquifer (ESPA) Comprehensive Aquifer Management Plan implementation through additional water supply for natural and managed aquifer recharge.

In recent years, water management activities for the ESPA, affecting both surface and spring flows as well as aquifer levels, have been driven by negotiations between the Surface Water Coalition and the Idaho Ground Water Appropriators. In 2015, an agreement between these entities 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 provided 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 agreement was revisited and modified in 2024, however, the goals of addressing declining aquifer levels and improving spring flows remained.

On October 21, 2022, the director of the IDWR signed an order amending the 1993 Eastern Snake River Plain Moratorium, re-establishing a moratorium on the issuance of new consumptive water rights permits from surface and groundwater tributary to the Snake River upstream from Milner Dam, as well as from Milner Dam to King Hill. The order also created a new moratorium on the issuance of new consumptive water right permits from surface and groundwater tributary to the Snake River between King Hill and Swan Falls Dam. In issuing the moratorium, the director concluded that additional appropriation of surface or groundwater upstream of Swan Falls could lead to a violation of the minimum streamflow rights at Swan Falls Dam. The moratorium is important to Idaho Power because it demonstrates the role the State of Idaho has in protecting a minimum water supply for the company's hydroelectric system.

Oregon Policy & Activities

State of Oregon 2024 Biennial Energy Report

In 2017, the Oregon Department of Energy (ODOE) introduced House Bill (HB) 2343, which required ODOE to develop a new biennial report to inform local, state, regional, and federal energy policy development and energy planning and investments. The *2024 Biennial Energy Report*[9] provides foundational energy data about Oregon and examines the existing policy landscape while identifying 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.

Renewable energy continues to make up an increasing share of Oregon's energy mix each year. With the increase in renewable energy sources, other resources in the electricity mix have changed as well. In the 2024 Biennial Energy Report, ODOE changed the way it calculates the Electricity Resource Mix, which introduced "Unspecified" as a category in its resource mix. Under the new categories, Oregon's resource mix for 2022 was 12.64% coal, 16.63% natural gas, and 22.77% unspecified.

[9] Retrieved April 2025: oregon.gov/energy/Data-and-Reports/Documents/2024-Biennial-Energy-Report.pdf.

The main theme of the 2024 Biennial Energy 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, policymakers, state and local governments, and private-sector business and industry leaders.[10]

Oregon Renewable Portfolio Standard and Emissions Reduction Requirements

As part of the *Oregon Renewable Energy Act of 2007* (Senate Bill 838), the State of Oregon established a Renewable Portfolio Standard (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% of Oregon's total retail electric sales. In 2023 per EIA data, Idaho Power's Oregon customers represented 1.1% of Oregon's total retail electric sales. As a smaller utility in Oregon, Idaho Power will likely have to meet a 5% RPS requirement beginning in 2025, however this could increase to 10% if retail sales grow to 1.5% of Oregon's total retail electric sales, pushing Idaho Power into a larger compliance category.

In 2016, the Oregon RPS was updated by Senate Bill 1547 to raise the target from 25% by 2025 to 50% renewable energy by 2040; however, Idaho Power's obligation as a smaller utility does not change. Additionally, the Oregon Legislature in 2021 passed HB 2021, which sets GHG emissions reduction requirements associated with electricity sold to utility customers. Idaho Power is exempt from the conditions of this bill, as the company has fewer than 25,000 retail customers in Oregon.

The State of Idaho does not currently have an RPS.

Regional Policies & Activities

Western Resource Adequacy Program

The Western Resource Adequacy Program (WRAP) is the first regional reliability planning and compliance program in the western United States. WRAP is a region-wide planning process that assesses resource adequacy across the footprint and seeks to increase regional reliability while providing economic benefits associated with regional coordinated planning. WRAP facilitates a reliability program that allows for available resources to be shared among participants during short-term periods of resource deficiency. The goal of this program is to maintain reliability across all participants' systems over the course of an operating season in which some participants may experience peak load conditions or extreme weather events. WRAP is being

[10] ODOE, *2024 Biennial Energy Report*.

developed through a collaborative, participant-driven process that is facilitated by the Western Power Pool (WPP). WPP is the program administrator of WRAP, including managing implementation of WRAP rules and tariff.

To facilitate the sharing of resources among participants, WRAP is organized into two parts over two seasons (summer and winter): an advanced viewing of resources—called the forward showing—and an operations phase during which resources can be shared in times of need. Each season has its own forward showing and operations program, and each participant is individually responsible for complying with the forward showing and operations program requirements.

On February 10, 2023, FERC approved the WRAP tariff and underscored the importance of a regional program and the enhanced reliability and resource adequacy that WRAP would bring.[11] With the WRAP tariff approved, the program is continuing to build out its processes and participants are continuing to gain program experience through non-binding participation. The program's construct is that participants will transition to a fully binding program in summer 2027 or winter 2027/2028. While participation in WRAP is voluntary, binding participants must meet capacity and delivery requirements and pay participation costs.

As of May 2025, more than 20 entities[12], including Idaho Power, are participating the program.

Please see the Western Resource Adequacy Program Modeling section in *Appendix D—System Reliability and Regulating Reserves* for details on how Idaho Power modeled WRAP benefits in the 2025 IRP.

Regional Power Markets

There are two markets under development in the Western Interconnection, California Independent System Operator's (CAISO) Extended Day Ahead Market (EDAM) and Southwest Power Pool's Markets+ (Markets+). The potential benefits of enhanced reliability and economic efficiency through improved optimization and coordination within the Western electricity network are the main drivers of this exploration. The company is assessing the potential benefit of participating in EDAM or Markets+.

[11] FERC, ER22-2762-000 National Order, p. 10. ("Through increased coordination, we find that the WRAP has the potential to enhance resource adequacy planning, provide for the benchmarking of resource adequacy standards, and more effectively encourage the use of western regional resource diversity compared to the status quo.")

[12] westernpowerpool.org/news/wrap-faqs retrieved April 29, 2025

3. CLEAN ENERGY & CLIMATE CHANGE

Idaho Power assesses the potential impacts of climate change on industry, customers, and long-term planning. This chapter of the IRP focuses on identifying climate-related risks, discussing the company's approach to monitoring and mitigating identified risks, and examining climate-related risk considerations in the IRP.

When assessing a changing climate, it is important to underscore the distinction between mitigation and adaptation. Climate change mitigation refers to efforts associated with reducing the severity of climate change. In contrast, climate change adaptation involves understanding the scope of potential physical and meteorological changes that could result from climate change and identifying ways to adapt to such changes. Idaho Power's risk assessment examines both mitigation and adaptation in the sections below.

Climate Change Mitigation

A Cleaner Energy Mix

The 2024 energy mix is noted below. The company's clean generation mix is primarily driven by hydropower.

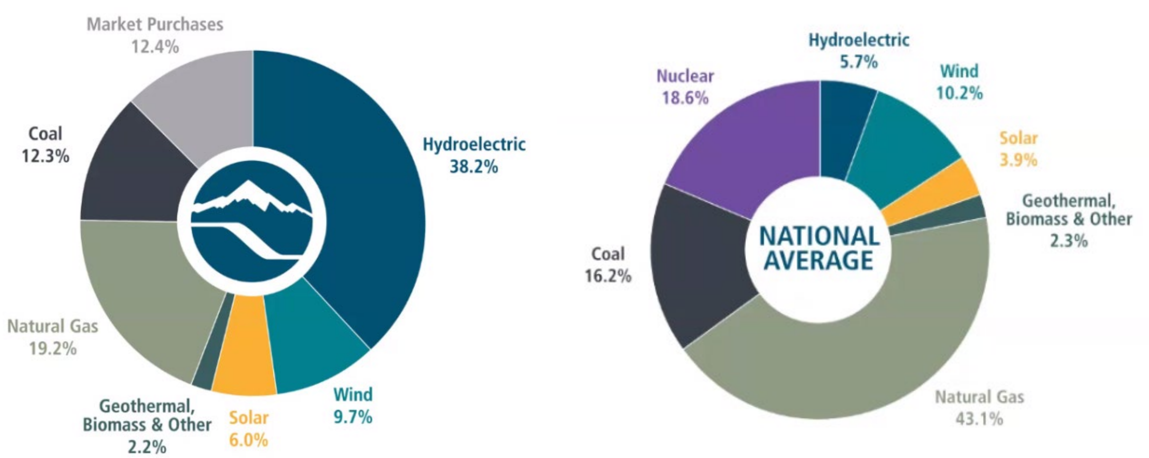

Figure 3.1 Idaho Power's 2024 energy mix compared to the national average

The company sells the RECs associated with renewable energy, meaning that the overall mix does not represent the energy delivered to customers.

Our Clean Energy Goal—Clean Today. Cleaner Tomorrow.®

Set in 2019, Idaho Power's long-term goal remains an aspirational target as the company looks toward increasingly cost-effective clean energy solutions and up-and-coming technological advances. The goal is to achieve 100% clean (i.e. non-carbon emitting) company-owned generation by 2045. Idaho Power is expecting that emerging technologies and cost reductions for existing technology will help reach this goal. The key to achieving this goal is the company's existing backbone of hydropower—our largest energy source—as well as the plan contained in the Preferred Portfolio that continues reducing carbon emissions.

The Preferred Portfolio identified in the 2025 IRP reflects a diverse mix of generation and transmission resources that ensures reliable, affordable energy. Under current federal and state policies, achieving a 100% clean energy portfolio by 2045 will require additional technological advances and reductions in cost. The company will continue to update the IRP every two years, including analyzing new and evolving technologies to provide low-cost, reliable energy to Idaho Power customers.

Clean Energy Your Way

Idaho Power has long supported customers' individual goals and initiatives to achieve clean energy through various program offerings. Idaho Power provides its customers optional clean energy offerings under the Clean Energy Your Way (CEYW) Program (Schedule 62).

CEYW allows the company to better meet the needs of the growing number of customers pursuing or exploring sustainability targets, such as powering their operations on 100% renewable energy in an amount up to or equal to the customer's usage.

Schedule 62 includes two options currently available for customers:

1. CEYW—Flexible, a REC purchase program available to all customers in Idaho and Oregon
2. CEYW—Construction, an option for the company's largest customers in Idaho

Clean Energy Your Way—Flexible

Available since 2001, the CEYW—Flexible offering allows customers to cover their energy use with RECs. Customers can choose to cover 100% of their monthly energy use or buy RECs in 100 kilowatt-hour (kWh) blocks—and they can change or cancel their enrollment anytime. Another option allows business customers to make a large purchase of RECs at a competitive market price.

Clean Energy Your Way—Construction

The CEYW—Construction offering enables Special Contract and Schedule 19 customers in Idaho (over 1 MW) to partner with Idaho Power to develop new renewable resources through a long-term arrangement. Customers work with Idaho Power and provide input on the size, location, and type of renewable project (i.e., wind or solar) to meet their individual requirements, with project size not to exceed 110% of the customer's annual energy requirements. The CEYW–Construction renewable project must connect to Idaho Power's system, but customers are able to claim the renewable attributes as their own.

This offering requires detailed, negotiated contracts between an Idaho customer and Idaho Power, which must be reviewed and approved by the IPUC. Idaho Power has entered several CEYW–Construction agreements to support our larger customers' clean energy goals. The 2025 IRP preferred portfolio includes the CEYW–Construction resources for both current and planned participants in this program.

Details about the modeling inputs of the CEYW program can be found in the Loss of Load Expectation sections of *Appendix D—System Reliability and Regulating Reserves*.

Idaho Power Carbon Emissions

Idaho Power's CO_2 emissions from generating resources are below the national average for electric utilities in the United States, in terms of emissions intensity. Figure 3.2 shows the long-term trend via the light green dashed line and the actual amounts via the dark green solid line.

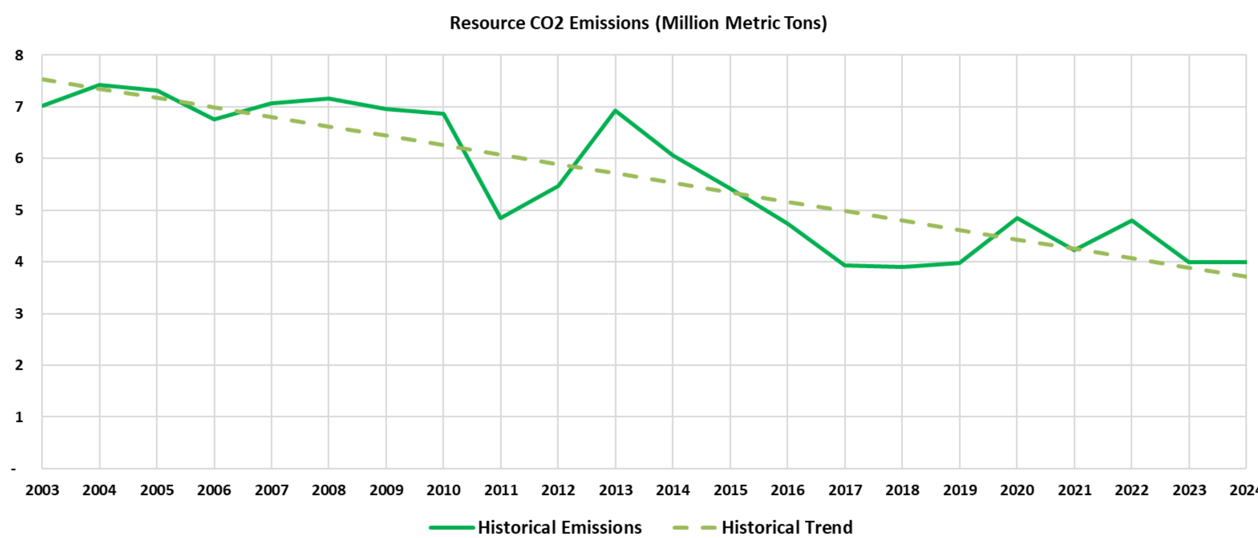

Figure 3.2 Estimated Idaho Power CO_2 emissions (million metric tons)

Since 2009, the company has met various voluntary goals to reduce the amount of CO_2 emitted from its energy-generating resources. From 2021 to 2024, Idaho Power reduced carbon emissions by an average of 42% compared to 2005. The general trend continues to be downward as Idaho Power converts coal generation facilities to natural gas and adds clean resources. The reductions in 2023 and 2024 helped the company get closer to its medium-term goal due to higher hydropower generation and the addition of renewable resources in those years, which offset the need to use coal and other carbon emitting generation resources.

Generation and emissions from company-owned resources are included in the CO_2 emissions intensity calculation. Idaho Power's progress toward achieving its intensity reduction goals and additional information on Idaho Power's CO_2 emissions are reported on the company's website.[13]

Climate Adaptation

Studies have assessed the potential impact of climate change on the Pacific Northwest. The Fifth National Climate Assessment[14] and the River Management Joint Operating Committee[15] addressed water availability in the region under multiple climate change and response scenarios. Both reports highlight the uncertainty related to future climate projections. However, many of the model projections show warming temperatures and increased precipitation into the future.

Risk Identification and Management

Identification of and response to specific risks are managed via Idaho Power's annual Enterprise Risk and Compliance Assessment, which includes a robust review of current and emerging regulations and other factors impacting the company's business and operations. Management of each risk is identified and includes risk oversight by an internal department or committee, internal or external auditor process review, and the company's Board of Directors.

Climate change-specific risks are an evolving category that includes, but may not be limited to, changes in customer usage and hydro generation due to changing weather conditions and severe weather events. Wildfire is another category of risk that is influenced, although not solely driven by, climate change. In Idaho Power's service area, climate-related risks are evaluated considering potential for extreme weather conditions, such as severe storms, lightning, high winds, icing conditions, droughts, heat waves, fires, floods, and snow loading. Policy-oriented risk with respect to climate change can be understood as climate-oriented laws, rules, and regulations that could impact Idaho Power operations and planned capital expenditure. These specific climate-oriented risks are examined in the following sections.

Weather Risk

Changing and severe weather conditions, such as increased frequency and severity of storms, lightning, droughts, heat waves, fires, floods, snow loading, and other extreme weather events

[13] Retrieved April 2025: idahopower.com/energy-environment/energy/energy-sources/our-path-away-from-coal/

[14] nca2023.globalchange.gov/

[15] bpa.gov/p/Generation/Hydro/Pages/Climate-Change-FCRPS-Hydro.aspx.

can adversely affect Idaho Power's operations. These events have the potential to damage transmission, distribution, and generation facilities; cause service interruptions and extended outages; increase costs and other operations and maintenance expenses—including emergency response planning and preparedness expenses—and limit Idaho Power's ability to meet customer energy demand.

Idaho Power's Atmospheric Science group—in collaboration with Boise State University, the Idaho National Laboratory (INL), and IWRB—worked together in 2020 to advance high performance computing within Idaho. This public–private partnership resulted in a shared high performance computing resource that is still in use today, and benefits Idaho Power customers by providing a cost-effective, high-performance computing system to run complex weather models and conduct research to refine weather forecasting capabilities. This system has improved the forecasting of renewable energy sources and helped Idaho Power manage the company's hydroelectric system and cloud-seeding operations. Additionally, Idaho Power's wildfire mitigation efforts are assisted by this high-performance computing system.

Idaho Power modeled an Extreme Weather Scenario to capture the impacts of extreme and changing weather conditions as part of the 2025 IRP analysis. The results can be reviewed in Chapter 10.

Wildfire Risk

In recent years, the Western United States has experienced an increase in the frequency and intensity of wildland fires (wildfires). Several factors have contributed in varying degrees to this trend including climate change, increased human encroachment in wildland areas, historical land management practices, and changes in wildland and forest health. Idaho Power takes several proactive steps to address the risk of wildfire in its service area.

The company's wildfire mitigation measures are outlined in its Wildfire Mitigation Plan (WMP). The WMP is updated annually in advance of each fire season.[16]

Wildfire impact on transmission availability is modeled in the 2025 IRP reliability analysis. For details, see the Modeling Wildfire Impact section of *Appendix D—System Reliability and Regulating Reserves*.

Water and Hydropower Generation Risk

Lower hydropower generation can increase power supply costs as the company derives a significant portion of its power supply from its hydropower facilities.

[16] Retrieved April 2025: docs.idahopower.com/pdfs/Safety/WildfireMitigationPlan.pdf

Specific programs the company has implemented to responsibly manage water use include working with federal and state government agencies to monitor key water supply indicators (e.g., snow water equivalent, precipitation, temperature), conducting cloud seeding, monitoring surface and groundwater flows, and producing short- and long-range streamflow forecasts to inform the company's water operations.

Water supply within the Snake River Basin is primarily snowpack driven. To increase the amount of snow that falls in drainages that feed the Snake River—subsequently benefiting hydropower generation, irrigation, recreation, water quality and other uses—Idaho Power collaboratively conducts a successful cloud-seeding program in the Snake River Basin. Another significant source of water for Idaho Power's hydro system is the ESPA. This aquifer covers approximately 10,800 square miles in southern Idaho and supports significant economic activity in the agricultural sector as well as other beneficial uses. For much of the year, the ESPA comprises most of the water supply from Milner Dam to Swan Falls Dam via springs that discharge from the aquifer to the Snake River. Each year, discharge from the ESPA accounts for 40% of the water supply for the HCC. In dry years and during baseflow conditions in the summer, the aquifer accounts for well over 50% of the water supply for Idaho Power's hydroelectric system. The aquifer has been in a state of general decline over the past several decades. Climate change and other developments with the ESPA could increase demands on groundwater resources, which could ultimately impact hydropower production on Idaho Power's system.

Idaho Power stays current on the rapidly developing climate change research in the Pacific Northwest. The River Management Joint Operating Committee Second Edition Long-Term Planning Study[17] shows the natural hydrograph could see lower summer base flows, a shift in timing to earlier peak runoff, higher winter baseflows, and an overall increase in annual natural flow volume. For Idaho Power's hydro system, the findings support that upstream reservoir regulation significantly dampens the effects of this shift in natural flow to Idaho Power's system. Furthermore, the studies indicate Idaho Power could see July–December regulated streamflow relatively unaffected and January–June regulated streamflow increasing over the 20-year planning period.

Policy Risk

Changes in legislation, regulation, and government climate-related policy may have a material impact on Idaho Power's business in the future. Specific legislative, executive, and regulatory proposals and actions and recently enacted legislation that could have a material impact on

[17] Climate Change and FCRPS - Bonneville Power Administration retrieved April 2025

Idaho Power include, but are not limited to, tax reform, tariffs, utility regulation, carbon-reduction initiatives, infrastructure renewal programs, environmental regulation, and modifications to accounting and public company reporting requirements.

Policy-related risk is addressed in several ways in Idaho Power's long-term planning. For each IRP, the company models existing policies, including known expiration or sunset dates. Idaho Power does not model specific policies to which it is not subject. For example, the Oregon Legislature's HB 2021 sets emissions reduction standards for electric utilities, but Idaho Power is exempt because it has fewer than 25,000 retail customers in its Oregon service area. As a result, the company did not model HB 2021 requirements for Idaho Power's portfolio.

At the time of the 2025 IRP, state-level climate policies did not exist in Idaho and did not apply to Idaho Power in Oregon. Several climate-related laws and regulations have been implemented on the federal level. However, this is a rapidly changing area of law and many of those laws and regulations are likely to be modified, perhaps significantly, in future years. To account for this potential, the company modeled scenarios with different carbon emissions regulations and varying prices on carbon. These scenarios are detailed in Chapter 9 of this report.

Modeling Climate Risks in the IRP

While the above referenced climate-related risks are addressed and accounted for in different operational ways by Idaho Power, the company also extended climate-related risk assessment to the 2025 IRP. The company assessed specific scenarios to explore the impact these events would have on Idaho Power's system. These scenarios are summarized below and detailed in Chapter 9. Portfolios.

The Extreme Weather scenario includes an increased demand forecast associated with extreme temperature events and a decreased supply of water.

Idaho Power assessed carbon regulation in a few ways. First, Idaho Power's planning case for the IRP assumes the EPA 111(d) rules on carbon emissions apply for the 20-year IRP planning horizon. Idaho Power also modeled scenarios without the EPA 111(d) rules on carbon emissions for comparison. Additionally, the company developed a portfolio that assumed a high carbon price adder to compare it to the portfolios built under the planning case.

The company incorporated an adjustment to the availability of certain transmission facilities in the 2025 IRP reliability studies to account for wildfire risk. A detailed description on how wildfire risk was modeled is presented in *Appendix D—System Reliability and Regulating Reserves*.

By considering the above scenarios and varying assumptions, the 2025 IRP was able to assess possible risk associated with both mitigation and adaptation to climate change.

4. IDAHO POWER TODAY

Customer Load and Growth

Back in 2004, Idaho Power served nearly 439,000 metered customers in Idaho and Oregon. In 2024, Idaho Power served just over 649,000 metered customers. Firm peak-hour load increased from 2,843 MW in 2004 to 3,793 MW in July 2024, which represents the company's current system peak-hour record.

Residential construction growth in southern Idaho

Average firm load increased from 1,671 average MW (aMW) in 2004 to 1,966 aMW in 2024. Additional details of Idaho Power's historical load and customer data are shown in Figure 4.1 and Table 4.1. The data in Table 4.1 suggests each new customer adds nearly 6 kilowatt (kW) to the peak-hour load and approximately 3 average kW (akW) to the average load.

Idaho Power anticipates adding an average of 10,100 customers each year throughout the 20-year planning period. The load forecast for the entire system predicts summer peak-hour load requirements will grow to 4,949 MW by 2031, approximately 200 MW per year on average over the 5-year planning period (2026–2031). More detailed customer and load forecast information is presented in Chapter 8 and in *Appendix A—Sales and Load Forecast*.

Table 4.1 Historical load and customer data

Year	Peak Firm Load (MW)	Average Firm Load (aMW)	Customers[1]
2004	2,843	1,671	438,912
2005	2,961	1,661	456,104
2006	3,084	1,747	470,950
2007	3,193	1,810	480,523
2008	3,214	1,816	486,048
2009	3,031	1,744	488,813
2010	2,930	1,680	491,368
2011	2,973	1,712	495,122
2012	3,245	1,746	500,731
2013	3,407	1,801	508,051
2014	3,184	1,739	515,262
2015	3,402	1,748	524,325
2016	3,299	1,750	533,935
2017	3,422	1,807	544,378
2018	3,392	1,810	556,926
2019	3,242	1,790	570,953
2020	3,392	1,809	586,565
2021	3,751	1,881	602,983
2022	3,568	1,947	617,243
2023	3,615	1,913	632,136
2024	3,793	1,966	648,352

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

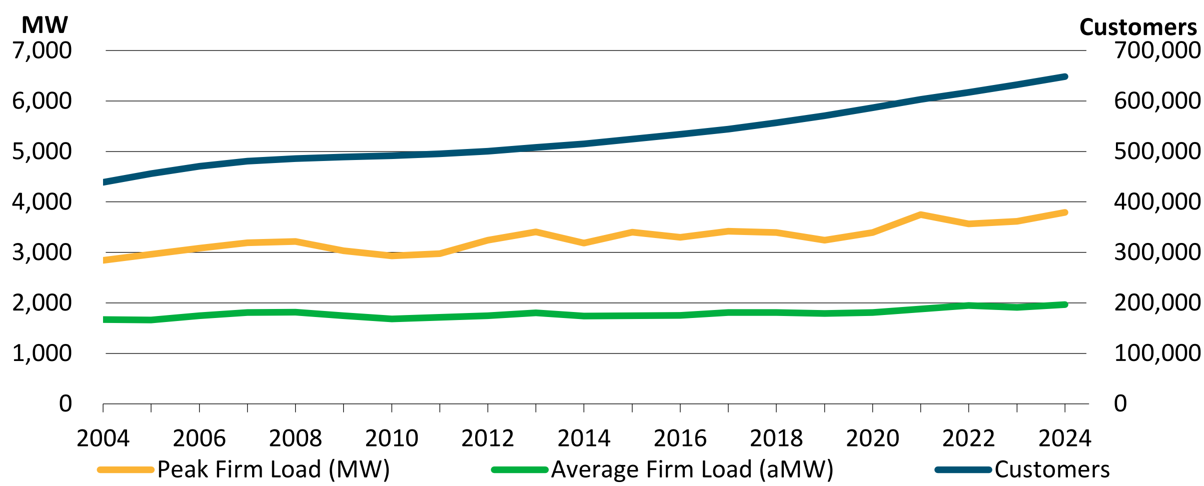

Figure 4.1 Historical load and customer data

2024 Energy Sources

Idaho Power's energy sources for 2024 are shown in Figure 4.2.

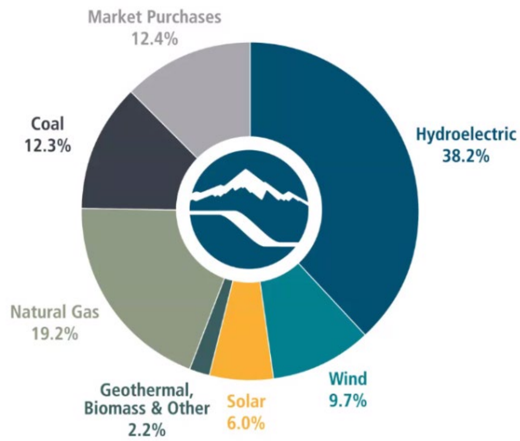

Figure 4.2 Idaho Power's 2024 energy mix

This energy mix shows the energy we generate from company-owned resources and energy we buy through long-term contracts with wind, solar, biomass, geothermal and small-scale hydro generators. The overall mix does not represent the energy delivered to customers for two reasons. First, we participate in the wholesale energy market and sell energy both to other utilities and to retail customers. Second, some of our purchased power from renewable sources comes with a Renewable Energy Credit, or REC.

Existing Supply-Side Resources

Table 4.2 shows Idaho Power's existing company-owned resources, plant capacities, and general locations as of 2025.

Table 4.2 Existing resources

Resource	Type	Capacity* (MW)	Location
American Falls	Hydroelectric	92.3	Upper Snake
Bliss	Hydroelectric	75.0	Mid-Snake
Brownlee	Hydroelectric	675.0	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	411.1	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	14.7	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 & B	Hydroelectric	34.5	Mid-Snake
Jim Bridger	Coal/Natural Gas	707.0	Southwest Wyoming
North Valmy	Coal	134.0	North Central Nevada
Langley Gulch*	Natural Gas—CCCT	292.9	Southwest Idaho
Bennett Mountain*	Natural Gas—SCCT	174.6	Southwest Idaho
Danskin*	Natural Gas—SCCT	264.6	Southwest Idaho
Salmon Diesel	Diesel	5.5	Eastern Idaho
Hemingway BESS	Battery Energy Storage	116.0	Southwest Idaho
Black Mesa BESS	Battery Energy Storage	40.0	Southwest Idaho
Franklin BESS	Battery Energy Storage	60.0	Southwest Idaho
Distributed BESS	Battery Energy Storage	4.0	Southwest Idaho
Happy Valley BESS	Battery Energy Storage	80.0	Southwest Idaho
Total existing plant capacity		3,704.0	

*Capacity as reported in FAC-008 Normal Ratings

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

Hydroelectric Facilities

Idaho Power operates 17 hydropower projects located on the Snake River and its tributaries. Over the last 30 years, these hydropower facilities averaged total annual generation of approximately 876 aMW, or 7.7 million MWh.

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% of Idaho Power's annual hydroelectric power. 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 is 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 *Endangered Species Act*.

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 equates to approximately 1 million acre-feet of water. Both Oxbow and Hells Canyon reservoirs have significantly smaller active storage capacities—approximately 0.5% and 1% 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 from the United States Army Corps of Engineers as required in 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 United States Bureau of Reclamation releases water from its 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. Idaho Power works with federal and state partners and other stakeholders to pass these federal flow augmentation releases without delay through the HCC.

As part of a 2005 interim HCC relicensing agreement, Idaho Power agreed to provide up to 237,000 acre-feet of water from Brownlee Reservoir for flow augmentation, in addition to the federal flow augmentation releases. Idaho Power uses its best efforts to hold Brownlee Reservoir at or near full elevation (approximately 2,077 feet above mean sea level) through June 20. Thereafter, Brownlee Reservoir is drafted to an elevation of 2,059 feet (releasing up to 237,000 acre-feet) by August 7. Although the portion of the 2005 interim agreement relating to flow augmentation releases has expired, Idaho Power continues to provide these flow augmentation releases annually. Idaho Power anticipates the Brownlee flow augmentation targets to be included in the upcoming FERC license.

Brownlee Reservoir's releases are managed to maintain operationally stable flows below Hells Canyon Dam in the fall because of the Fall Chinook Program. The stable flow is set at a level to protect fall Chinook spawning nests. During fall Chinook operations, Idaho Power attempts to refill Brownlee Reservoir by the first week of December to meet winter loads. The Fall Chinook Program 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, Upper and Lower 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, C.J. Strike, and Swan Falls projects.

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 Idaho Department of Water Resources' Water Supply Bank[18] 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.

Jointly Owned Coal and Gas Facilities

Jim Bridger

Idaho Power owns one-third, or 707 MW of net dependable capacity, of the Bridger power plant located near Rock Springs, Wyoming. The Bridger plant consists of four generating units. PacifiCorp has two-thirds ownership and is the operator of the Bridger facility. In 2024, PacifiCorp and Idaho Power converted units 1 and 2 from coal to natural gas. Units 3 and 4 continue to operate on coal. For additional details on the Bridger plant, refer to Chapter 5. Future Supply-Side Generation and Storage Resources. For the 2025 IRP, Idaho Power used the Aurora model's capacity expansion capability to evaluate a range of possibilities for the company's continued participation in the Bridger units 3 and 4.

North Valmy

Idaho Power and NV Energy are each 50% co-owners of the North Valmy coal power plant located near Winnemucca, Nevada. NV Energy is the operator of the North Valmy facility. Idaho Power's participation in the coal operations of North Valmy Unit 1 ceased at year-end 2019. Idaho Power currently participates 50%, or 134 MW of net dependable capacity, in the second generating unit at North Valmy.

In late 2025 and early 2026, Idaho Power and NV Energy will convert both units 1 and 2 to natural gas instead of coal. After conversion, both companies will be participating in and receiving generation from both units. Idaho Power's expected share of net dependable capacity from the combination of units will be 261 MW.

[18] idwr.idaho.gov/iwrb/programs/water-supply-bank/

Natural Gas Facilities and Diesel Units

Bennett Mountain

Idaho Power owns and operates the Bennett Mountain plant, which consists of a 176 MW[19] natural gas simple-cycle combustion turbine (SCCT) located in Mountain Home, Idaho. The Bennett Mountain plant was commissioned in 2005.

Evander Andrews Complex (Danskin)

The Danskin facility is located northwest of Mountain Home, Idaho. Idaho Power owns and operates one 176 MW[20] SCCT and two 39 MW[21] SCCTs at the facility. The two smaller turbines were installed in 2001, and the larger turbine was installed in 2008.

Langley Gulch

Idaho Power owns and operates the Langley Gulch plant, which uses a nominal 299 MW natural gas combined-cycle combustion turbine (CCCT). The plant also has duct burners that provide an additional 20 MW of achievable capacity. The Langley Gulch plant, located south of New Plymouth, Idaho, became commercially operational in June 2012.

Diesel

Idaho Power owns and operates two diesel generation units in Salmon, Idaho. The Salmon units have a combined generator nameplate rating of 5.5 MW. These units primarily provide emergency backup generation.

Battery Energy Storage Systems

BESS hold a critical role for Idaho Power as the company provides reliable and affordable energy in the face of rapidly growing demand for electricity and an increasing need for integration of renewable resources. Idaho Power owns the following BESS facilities:

Hemingway BESS

In 2023, an 80-MW BESS was installed at the company’s Hemingway substation in Owyhee County. The company’s BESS at Hemingway is designed to discharge stored energy at a maximum discharge rate of 80 MW and has a total energy storage capacity of 320 MWh.

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[19] Generating capacity (MW) at ISO reference temperature of 59 degrees Fahrenheit. Unit by unit capacity varies with ambient conditions and is higher in the winter and lower at peak summer loads.

[20] After an upgrade in fall 2023, Danskin’s larger unit uprated from a capacity of 163 MW.

[21] Generating capacity (MW) at ISO reference temperature of 59 degrees Fahrenheit. Unit by unit capacity varies with ambient conditions and is higher in the winter and lower at peak summer loads.

In 2025, the company installed an additional 36-MW/144-MWh BESS (Hemingway BESS Expansion). The total BESS capacity at Hemingway is currently 116 MW/464 MWh. Additionally, a 50-MW/200-MWh BESS expansion at the Hemingway substation is planned to come online by summer 2026, pending approval by the IPUC.

Black Mesa BESS

A 40-MW/160-MWh BESS was built adjacent to the 40-MW Black Mesa Solar facility in Elmore County and came online in 2023.

Distribution-Connected Storage

Four different distribution-connected storage projects came online in 2024. The distribution-connected storage projects serve a dual purpose. In addition to providing the system with capacity, the project installations will assist in alleviating transformer peak load as they are in distribution substations where transformer upgrades can be deferred. The four projects are located at the Filer, Weiser, Melba, and Elmore distribution substations for a combined capacity of 11 MW.

Franklin BESS

A 60-MW/240-MWh BESS is installed adjacent to the 100-MW Franklin Solar facility in Twin Falls County. The BESS project came online in 2024.

Happy Valley BESS

An 80-MW/320-MWh BESS is planned for installation at the company's Happy Valley substation in Canyon County. The 80-MW BESS is scheduled to come online in summer 2025.

Boise Bench BESS

A 200-MW/800-MWh BESS is planned for installation at the company's Boise Bench substation in Ada County. The 200-MW BESS is scheduled to come online in summer 2026; 50 MW of which is pending approval by the IPUC.

Customer Generation Service

Idaho Power's on-site generation services allow customers to generate power on their property and connect to Idaho Power's system. For customers with exporting systems, the energy generated is first consumed on the property itself, while excess energy flows on to the company's grid. Most customer generators use solar PV systems. As of year-end 2024, there were 19,151 customer on-site generation systems interconnected through the company's customer generation tariffs with a total capacity of 175.59 MW. At that time, the company had received completed applications for an additional 452 solar PV systems, representing an incremental capacity of 16.35 MW. For further details regarding customer-owned generation resources interconnected through the company's on-site generation offerings, see tables 4.3 and 4.4.

Table 4.3 Customer generation service customer count as of year-end 2024

Resource Type	Active[1]	Application Received	Grand Total
Idaho Total	**18,887**	**436**	**19,323**
Hydro	11		11
Solar	18,854	436	19,290
Wind	22		22
Oregon Total	**264**	**16**	**280**
Solar	264	16	280
Grand Total	**19,151**	**452**	**19,603**

[1]Includes active and active-pending expansion

Table 4.4 Customer generation service generation capacity (MW) as of year-end 2024

Resource Type	Active[1,2]	Application Received	Grand Total[2]
Idaho	**171.96**	**16.18**	**188.14**
Hydro	0.15	0.0	0.15
Solar	171.71	16.18	187.89
Wind	0.10	0.0	0.10
Oregon	**3.64**	**0.17**	**3.81**
Solar	3.64	0.17	3.81
Grand Total	**175.59**	**16.35**	**191.94**

[1]Includes active and active-pending expansion
[2]Totals may not sum due to rounding

Public Utility Regulatory Policies Act

As early 2025, Idaho Power had 129 PURPA contracts with independent developers for approximately 1,129 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. Figure 4.3 shows the percentage of the total PURPA nameplate capacity of each resource type under contract.

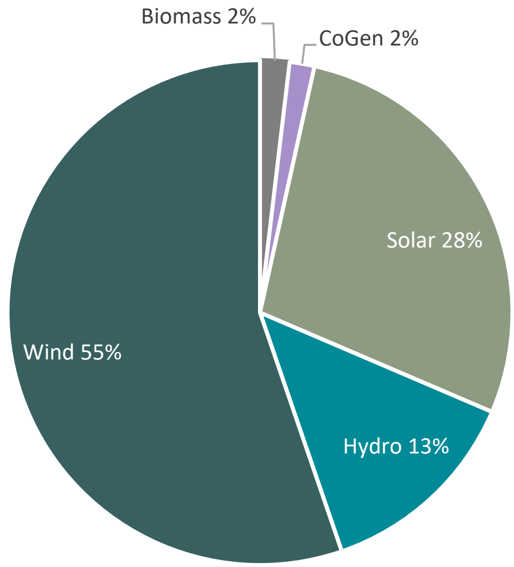


Figure 4.3 PURPA contracts by resource type

Details on signed PURPA contracts, including capacity and contractual delivery dates, are included in *Appendix C—Technical Report*.

Existing Non-PURPA Power Purchase Agreements and BESS Tolling 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 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 expires December 2027.

Raft River Energy

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. Under the PPA, Idaho Power is entitled to 51% of all RECs generated by the project. Idaho Power's contract with Raft River Energy I expires in April 2033.

Neal Hot Springs

In May 2010, the IPUC approved a PPA with USG Oregon, LLC, for approximately 27 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 expires in November 2037.

Jackpot Solar

In 2019, the IPUC approved a PPA with Jackpot Solar, LLC, for 120 MW of nameplate PV generation located north of the Idaho–Nevada state line near Rogerson, Idaho. Jackpot Solar began commercial operations in December 2022. Under the PPA, Idaho Power receives all RECs from the project. Idaho Power's contract with Jackpot Solar expires in December 2042.

Black Mesa Solar

In 2022, the IPUC approved a PPA with Black Mesa Energy, LLC, for the 40 MW Black Mesa Solar facility in Elmore County, Idaho, the output of which is dedicated for Micron's and the City of Boise's renewable energy use under the company's CEYW program. Black Mesa Solar began commercial operations on June 1, 2023, and is one of the first projects under Idaho Power's CEYW—Construction offering, enabling large customers to partner with Idaho Power on new, dedicated renewable energy resources to meet business sustainability goals. The RECs generated by the project will be retired on Micron's and the City of Boise's behalf. The PPA expires in June 2043.

Franklin Solar

In 2023, the IPUC approved a PPA with Franklin Solar, LLC, for 100 MW of nameplate PV generation located north of the Idaho-Nevada state line near Rogerson, Idaho (adjacent to Jackpot Solar). Franklin Solar began commercial operations in June 2024. Under the terms of the PPA, Idaho Power receives all RECs from the project. Idaho Power's contract with Franklin Solar expires in June 2049.

Pleasant Valley Solar

In 2023, the IPUC approved a PPA with Pleasant Valley Solar, LLC, for the 200-MW nameplate PV facility in Ada County, Idaho, the output of which is dedicated for Meta's renewable energy use under the company's CEYW program. Pleasant Valley Solar began commercial operations March 2, 2025. The RECs generated by the project will be transferred to Meta. The PPA with Pleasant Valley Solar expires in March 2045.

Kuna Storage

In 2024, the IPUC approved a battery-tolling agreement with Kuna BESS, LLC, for a 150 MW/600 MWh BESS facility in Kuna, Idaho. Under the agreement, Kuna BESS, LLC will build, own, and maintain the BESS facility that will provide 150 MW of capacity on Idaho Power's system, and Idaho Power will have the exclusive right to charge and discharge the project in exchange for a monthly payment. The Kuna BESS is scheduled to come online in 2025 and the agreement is expected to expire in 2045.

Contracted Non-PURPA Power Purchase Agreements and BESS Tolling Agreements

The following non-PURPA PPAs and BESS Tolling Agreements are under contract with Idaho Power but are not yet commissioned or online.

PVS2 Solar

In 2024, the IPUC approved a PPA with PVS2, LLC, for the 125 MW nameplate PV facility in Ada County, Idaho, the output of which is dedicated for Meta's renewable energy use under the company's CEYW program. PVS2 is expected to begin commercial operations in May 2026. The RECs generated by the project will be transferred to Meta. The PPA with PVS2 is expected to expire in May 2046.

Jackalope Wind

In 2024, Idaho Power executed a PPA with Jackalope Wind, LLC, for 298.9 MW of the Jackalope wind project, and simultaneously executed a Build Transfer Agreement with Jackalope Wind II Holdings, LLC, for 301.74 MW of the Jackalope wind project. The combined project is expected to begin commercial operations in June 2027. Idaho Power will receive the RECs generated by the project. The PPA with Jackalope Wind, LLC is expected to expire in June 2062. This project is pending approval by the IPUC.

Blacks Creek Solar

In 2024, Idaho Power executed a PPA with Blacks Creek Energy Center for the 320 MW Blacks Creek PV facility in Ada County, Idaho, the output of which will be dedicated for Meta's renewable energy use under the company's CEYW program. Blacks Creek is expected to begin commercial operations in December 2027. The RECs generated by the project will be transferred to Meta. The PPA with Blacks Creek is expected to expire in December 2047.

Crimson Orchard Solar and Storage

In 2025, Idaho Power executed a PPA with Crimson Orchard, LLC, for the 100 MW Crimson Orchard PV facility located in Elmore County, Idaho, and simultaneously entered a battery-tolling agreement with the same entity for an adjacent 100 MW/400 MWh BESS facility. Under the battery-tolling agreement, the BESS facility will provide 100 MW of capacity on Idaho Power's system for 20 years, and Idaho Power will have the exclusive right to charge and discharge the project in exchange for a monthly payment. Idaho Power will receive all RECs from the solar project. Crimson Orchard Solar and BESS are expected to come online in April 2027 and the agreements are expected to expire in April 2047. This project is pending approval by the IPUC.

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 leverages the regional power market to make purchases during peak-load periods. The existing transmission system is used to import these power purchases. Regional power markets benefit Idaho Power customers through decreased energy costs and increased reliability.

Transmission Import Rights

Idaho Power's interconnected transmission system facilitates market purchases to access resources to serve load. Idaho Power has the following connections 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)
6. Future: Idaho–Southern Nevada (SWIP-N)

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 7. Transmission Planning. Idaho Power reserves portions of its transmission capacity to import energy for load service (network set-aside). Set-aside capacity, along with existing contractual obligations, consumes nearly all of Idaho Power's import capacity on all paths (see Table 7.1 in Chapter 7. Transmission Planning).

Idaho Power continually evaluates market opportunities to meet near-term needs. Idaho Power enters into wholesale market purchase agreements for varying term lengths, from one month to multiple years, and for varying MW volumes. These purchases are delivered to Idaho Power's system either through the transmission rights held by the company, discussed in Chapter 7, or through the seller delivering the purchase to Idaho Power's border.

5. FUTURE SUPPLY-SIDE RESOURCES

Supply-side resources include traditional generation, renewable, and storage resources. As discussed in Chapter 6, 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 2025 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 2025 IRP is the 2024 Annual Technology Baseline report released by the National Renewable Energy Laboratory.[22] 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 Idaho Power's cost estimates and operating parameters for future supply-side resources, see the Supply-Side Resource section of *Appendix C—Technical Report*. For information on how the Effective Load Carrying Capability (ELCC) calculation is performed and the resulting variable and energy-limited resource ELCC values of future resources, see *Appendix D—System Reliability and Regulating Reserves*.

Clean Resources

Clean energy resources serve as the cornerstone of Idaho Power's existing portfolio. The company emphasizes a long and successful history of prudent clean energy resource development and operation, particularly related to its fleet of hydroelectric generators. In the 2025 IRP, a variety of renewable resources were included in all the portfolios analyzed. Renewable resources are discussed in general terms in the following sections.

Hydroelectric

Low-cost hydroelectric power is the foundation of Idaho Power's electrical generation fleet. Small-scale hydroelectric projects have been extensively developed in southern Idaho on irrigation canals and other sites, many of which have PPAs with Idaho Power. Because additional small-scale hydro resources are not expected to see significant further development, they have not been included as a selectable resource in the LTCE modeling.

Solar

The primary types of solar generation technology are utility-scale PV and distributed PV (primarily customer-owned). Solar PV converts sunlight directly into electrical energy.

[22] atb.nrel.gov/

Direct current energy passes through an inverter, converting it to alternating current that can then be used on-site or sent to the grid.

Targeted Grid Storage

Since the 2023 IRP, Idaho Power has installed four distribution-connected storage projects with the intent to defer growth-driven transmission and distribution (T&D) system investments. These projects are shown in Table 5.1.

Table 5.1 Targeted grid storage projects

Location	Year	Capacity (MW)	Energy (MWh)	Estimated Deferral Years
Filer	2024	2	8	5
Weiser	2024	3	12	10
Melba	2024	2	8	4
Elmore	2024	4	16	9

It is anticipated that there is potential for 5 MW of distribution-connected storage in a given year of the IRP that could provide locational value of T&D deferral. This resource option was added to the Aurora LTCE model.

While solar can occasionally be used to offset T&D investment, the instances are infrequent. Batteries can provide T&D deferral value and are a cost-effective addition to the system as load continues to increase. Batteries are also more practical to defer T&D investment because the land requirement is lower than that of solar or solar plus battery installations.

Geothermal

The basic principle of geothermal generation is that it converts heat from the earth into electrical energy. Based on exploration to date in southern Idaho, geothermal development has potential in Idaho Power’s service area; however, the potential for geothermal generation in southern Idaho remains somewhat uncertain. For the 2025 IRP, Idaho Power modeled binary enhanced geothermal systems as the type of geothermal. The time required to discover and verify geothermal resource sites is extensive; for this reason, Idaho Power modeled 2031 as the first selectable date for geothermal.

Wind

Wind turbines collect and transfer energy from high wind areas into electricity. A typical wind development consists of numerous wind turbines, with each turbine ranging in size from 1 to 5 MW. Most potential wind sites in southern Idaho lie between the south-central and the southeastern part of the state.

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.

Biomass

There are currently small quantities of biomass in Idaho Power’s service area, for example, 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. This resource option was considered in the 2025 IRP but was ultimately not added as a selectable resource in the Aurora LTCE model due to its limited availability at scale.

Thermal Resources

Conventional thermal generation resources are essential to providing dispatchable capacity, which is critical in maintaining the reliability of a bulk-electrical power system and integrating renewable energy into the grid. Conventional thermal generation technologies include natural gas, hydrogen, nuclear, and coal resources.

Natural Gas Resources

Natural gas resources use natural gas in a combustion turbine to generate electricity. CCCTs are commonly used for baseload energy, while faster ramping but less-efficient SCCTs and recips are generally used to generate electricity during peak-load periods and for integration of VER. Additional details related to the characteristics of natural gas resources are presented in the following sections. These resources are typically sited near existing natural gas transmission pipelines. All of Idaho Power’s existing natural gas generators are located adjacent to major natural gas pipelines. All new natural gas resources are assumed to be hydrogen convertible.

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 500 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 are generally more economic on a per-MW basis.

SCCT generating resources remain a viable option to meet demand during critical periods. 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.

Combined-Cycle Combustion Turbines

CCCT technology benefits from 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% under ideal conditions.

A traditional CCCT plant consists of a natural gas turbine/generator equipped with a heat recovery steam generator to capture waste heat from the turbine exhaust. 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.

Reciprocating Internal Combustion Engines

Reciprocating internal combustion engines (recip) are typically multi-fuel engines connected to a generator through a flywheel and coupling. They are typically capable of burning natural gas or other liquid petroleum products. 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 prior to delivery to the power plant location. 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. Recips provide unique benefits to the electrical grid. They are extremely flexible because they can provide ancillary services to the grid in just a few minutes. Engines can go from a cold start to full load in approximately two minutes.

Coal Conversion to Natural Gas

The most common method to convert an existing coal power plant to natural gas is to convert the existing steam boiler to use natural gas instead of coal. The conversion process can create numerous benefits, including reduced emissions, reduced plant O&M expenses, reduced capital costs, and increased flexibility. For purposes of the 2025 IRP, Idaho Power modeled this as an option for Bridger units 3 & 4.

Jim Bridger Coal to Natural Gas Conversion

Jim Bridger units 1 and 2 were converted to natural gas in 2024, as determined in the 2021 IRP. Units 3 and 4 continue to operate on coal with the currently installed Selective Catalytic Reduction (SCR).

For the 2025 IRP, Idaho Power used Aurora’s LTCE model to determine the best Bridger operating option specific to Idaho Power’s system, subject to the following constraints and 111(d) modeling variant:

- Unit 3
    - Operate on coal through 2029, convert to natural gas in 2030, and operate through the end of the IRP planning timeframe.
    - Exit the unit at the end of 2029.
    - Operate on coal through the end of the IRP planning timeline, with or without CCS.
- Unit 4
    - Operate on coal through 2029, convert to natural gas in 2030, and operate through the end of the IRP planning timeframe.
    - Exit the unit at the end of 2029.
    - Operate on coal through the end of the IRP planning timeline, with or without CCS.

Costs associated with continued capital investments and conversion were included in the analysis.

The Jim Bridger units provide system reliability benefits, particularly related to the company's flexible ramping capacity needs for Energy Imbalance Market (EIM) participation and reliable system operations.

North Valmy Coal to Natural Gas Conversion

North Valmy units 1 and 2 will be converted to natural gas in 2026, as determined in the 2023 IRP.

Hydrogen

Hydrogen, modeled as green hydrogen, is created from renewable electricity and water by electrolysis and has no carbon emissions.

Based on technology-specific research and studies, as well as input from IRPAC, the company allowed the model to select hydrogen generation beginning in 2037. While Idaho Power does not know which hydrogen technology may become commercially dominant, the company needed to select a technology profile to model within Aurora and, informed by available technology research, chose to model hydrogen as a SCCT with similar operating characteristics to natural gas units except for the fuel they burn and the emissions they produce.

The 2025 IRP is the second resource plan in which hydrogen-specific resources have been modeled; the company anticipates additional advancements associated with hydrogen and, as such, expects that ultimate development of the technology may differ from the current modeling approach. Idaho Power will continue to monitor advancements in hydrogen resources and refine its modeling assumptions in future long-term plans.

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 nuclear technologies in the IRP process. The company's long-term planning has typically assumed that an advanced-design small modular reactor (SMR) could be built on the INL site.

For the 2025 IRP, a 100 MW SMR was modeled as a selectable resource beginning in 2035—a timeline the company considered reasonable given the current state of the technology and the federal regulatory approval process. Compared to typical reactor designs, SMRs offer potential benefits, including smaller physical footprints, reduced capital investment, plant size scalability, and greatly enhanced flexibility. Grid services provided by the SMR include baseload energy and capacity.

Coal Resources

Conventional coal generation resources have been part of Idaho Power's generation portfolio since the early 1970s. No new coal-based energy resources were modeled as part of the 2025 IRP due higher capital costs and maintenance expenses compared to CCCTs, regulatory considerations and lack of commercial development.

Storage Resources

As increasing amounts of VERs are built within the region, the value of energy storage increases. There are many energy storage technologies at various stages of development, such as battery storage, hydrogen storage, compressed air, flywheels, pumped hydro storage, iron-air storage, and others. The 2025 IRP considered a variety of energy-storage technologies and modeled battery storage based on lithium ion (Li-ion) technology; longer-duration battery storage based on iron-air technology; and pumped hydro storage.

Energy storage can provide numerous grid services in various durations. Short-term services include ancillary services like frequency regulation, spinning reserve, and reactive power support. In the medium duration, storage today can provide peak shaving, arbitrage, T&D deferral, and firming for VERs. Long duration storage can shift energy between seasons.

Battery Storage

The dominant chemistry used in the market today is Li-ion, which provides significant advantages over other commercially available battery-storage technologies. Those advantages include high cycle efficiency, high cycle life, fast response times, and high energy density.

Idaho Power modeled Li-ion storage over other technologies in the 2025 IRP for short- and medium-duration storage. Idaho Power will continue to observe and evaluate the changing storage technology landscape.

Pumped Hydro Storage

Pumped hydro storage is a type of hydroelectric power that stores potential energy by pumping water from a lower to a higher elevation. Energy is generated when the water flows from the higher reservoir like a normal hydroelectric facility.

Pumped hydro storage projects are often large and become more feasible when large amounts of storage are identified as a system need.

Multi-Day Storage

Idaho Power has modeled multi-day duration, 100-hour storage, in the form of iron-air batteries since the 2023 IRP. Generally, these resources charge during periods of low demand and high renewable output in the spring and fall and discharge during periods of high demand in the summer and winter. The downside of this storage technology compared to other storage options is lower round-trip efficiency, which is expected to be less than half that of Li-ion batteries. Given these operating characteristics, this technology is best suited for inter-seasonal demand shaping and absorbing VER overproduction when they might otherwise be curtailed. As a technology that could serve a critical future need, Idaho Power will continue to monitor and model long-duration storage.

6. 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 [EE]) or a peak-system demand reduction focus (Demand Response [DR]). Energy efficiency has been a helpful resource that Idaho Power has depended on for decades. From 2002 to 2024, EE has provided average cumulative system load reductions of over 354 aMW. DR programs provided 323 MW of available capacity to reduce system demand in 2024. EE potential measures are screened for cost-effectiveness, then all achievable cost-effective EE potential resources are included in the IRP as a decrement to the load forecast before considering new supply-side resources. In addition, all achievable EE potential measures that were determined to not meet cost effective thresholds were bundled according to price and season. These bundles were made available for selection by the Aurora model.

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

The accumulated effect of EE is estimated to have reduced energy demand at the time of the 2024 system peak by 275 MW. Also included in the Preferred Portfolio is 320 MW of nameplate summer peak demand reduction from existing DR programs plus an additional 20 MW of DR by the end of the planning timeframe.

Energy Efficiency Forecasting—EE Potential Assessment

For the 2025 IRP, Idaho Power's third-party contractor, Applied Energy Group (AEG), provided a 20-year forecast of Idaho Power's EE potential from a utility cost test (UCT) perspective. The contractor also provided additional bundles of EE and their associated costs beyond the achievable economic potential for analysis in the 2025 IRP.

For the initial study, the contractor developed three levels of EE 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 EE 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.

2. *Economic*—Economic potential represents the adoption of all cost-effective EE measures. In the EE potential study, the contractor applied the UCT for cost-effectiveness, which compares lifetime energy and capacity benefits to the cost of the program. 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 EE 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 EE measure. These factors represent the ramp rates at which technologies will penetrate the market.

The load forecast entered into Aurora includes the reduction to customer sales of future achievable economic EE potential. Treatment of EE that could contribute beyond the decrement to the load forecast is discussed below.

Energy Efficiency Modeling

In addition to the baseline EE potential study that assessed technical, economic, and achievable potential in a manner consistent with past IRPs, the company modeled additional bundles of technically achievable EE and their costs in the Aurora model in the 2025 IRP.

Technically Achievable Supply Curve Bundling

In collaboration with AEG, an approach was established to allow technically achievable EE potential beyond the achievable economic potential, to be input into the Aurora model for possible selection. These bundles include measures that did not pass economic screening but were made available for selection depending on various scenarios determined by the model. Technically achievable potential differs from the broader technical potential category, as AEG applies a market adoption factor intended to estimate those customers likely to participate in programs incentivizing more efficient processes or equipment, similar to the approach used when forecasting achievable potential.

Six bundles of EE measures were created that were grouped by summer or winter measures, with both split into a low, mid, and high-cost bundles. Whether a measure belonged in the summer or winter groups depended on the ratio of peak winter to summer capacity determined by the measure's load shapes at the hour of seasonal peak need. The bundles were sized to be large enough for Aurora to recognize them as operationally viable resources, but small enough to keep the weighted average levelized cost reflective of the costs of the associated measures.

The bundles were then loaded into the Aurora software with a capacity, levelized cost, and an 8,760-hour load shape. Table 6.1 lists the average annual resource potential and average levelized cost for the bundles.

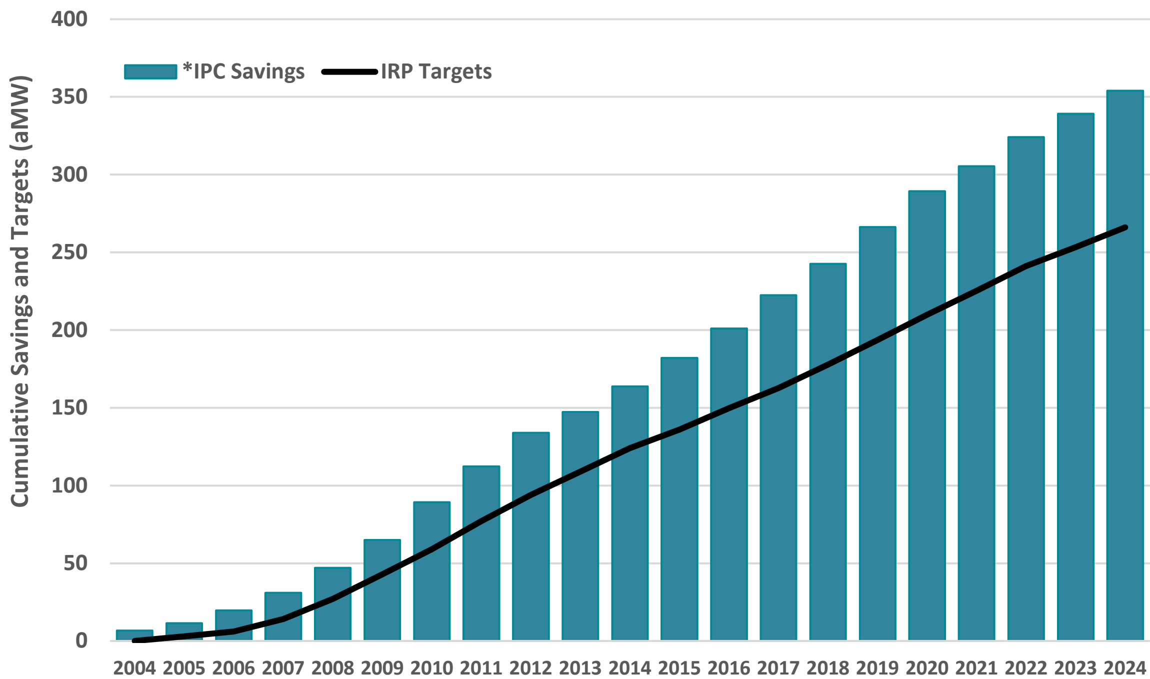
Table 6.1 EE bundles average annual resource potential and average levelized cost

Bundle	20-Year Average Annual Potential (aMW)	20-Year Average Real Cost ($/MWh)
Summer Low-Cost	12.6	$95
Summer Mid-Cost	12.7	$196
Summer High-Cost	18.8	$1,262
Winter Low-Cost	5.7	$65
Winter Mid-Cost	11.3	$136
Winter High-Cost	5.1	$870

DSM Program Performance and Reliability

Energy Efficiency Performance

EE investments since 2002 have resulted in a cumulative annual reduction of 354 aMW in 2024. Figure 6.1 shows the cumulative annual growth in EE savings from 2004 through 2024, along with the associated IRP targets developed as part of the IRP process since 2004.



*IPC Savings include Northwest Energy Efficiency Alliance non-code/federal standards savings

Figure 6.1 Cumulative annual growth in energy efficiency compared with IRP targets

Idaho Power's energy efficiency portfolio is currently a cost-effective resource. Table 6.2 shows the 2024 year-end program results, expenses, and corresponding benefit-cost ratios.

Table 6.2 Total EE portfolio cost-effectiveness summary, 2024 program performance

Customer Class	2024 Savings (MWh)	UCT ($000s)	Total Utility Benefits ($000s) (NPV*)	UCT: Benefit/ Cost Ratio	UCT Levelized Costs (cents/kWh)
Residential	24,472	$4,659	$4,116	.88	3.4
Industrial/commercial	90,336	$16,830	$37,283	2.22	2.0
Irrigation	4,290	$1,653	$2,702	1.65	3.7
Total**	**119,098**	**$27,056**	**$44,118**	**1.63**	**2.2**

* NPV=Net Present Value

** Total UCT dollars, benefit/cost ratio and levelized costs include indirect program expenses included in the portfolio level but not in the customer class level.

Note: Values may not add to 100% due to rounding. Excludes market transformation program savings.

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 6.3 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 and during the 2024 summer season, this program contributed 80% of the total potential demand-reduction capacity, or 259 MW. More details on Idaho Power's demand response programs can be found in *Appendix B—Demand-Side Management 2024 Annual Report*.

Table 6.3 2024 demand response program capacity

Program	Customer Class	Reduction Technology	2024 Total Demand Response Capacity (MW)	Percent of Total 2024 Capacity*
A/C Cool Credit	Residential	Central A/C	24	7%
Flex Peak Programs	Commercial/Industrial	Various	40.6	13%
Irrigation Peak Rewards	Irrigation	Pumps	258.8	80%
Total			**323.4**	**100%**

* Values may not add to 100% due to rounding

Figure 6.2 shows the historical annual demand response program capacity between 2004 and 2024. 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 being identified in the 2013 IRP.

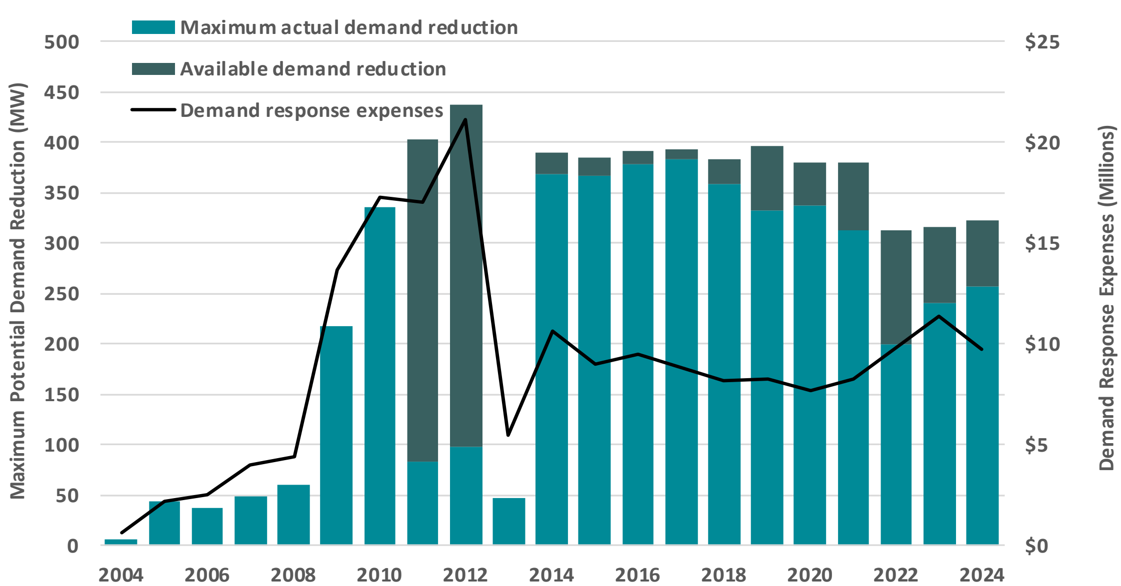


Figure 6.2 Historic annual demand response program performance

Demand Response Resource Potential

In the 2025 IRP, DR from all existing programs was committed to provide 320 MW of peak capacity during June and July throughout the IRP planning period, with a reduced amount of program potential available during August and September. Because the total potential from DR is dependent on anticipated load from program participants, the reduced amount of potential available during August and September is a result of irrigation load reducing over the DR program season.

For the 2025 IRP, Idaho Power leveraged AEG's 2022 DR assessment to estimate what additional DR potential may be available in Idaho Power's service area. Based on this study, Idaho Power grouped expansion of its current programs and other potential programs into similar price and characteristic buckets for analysis within the Aurora model.

This additional DR potential was represented by two separate buckets: 90 MW of existing program expansion and 55 MW of storage programs (for example, water heater or customer battery programs). DR was available for selection in the Aurora model in 10 MW and 5MW amounts for existing program expansion and storage programs respectively. Each program was available for selection each year based on expected possible program availability.

T&D Deferral Benefits

Energy Efficiency

For the 2025 IRP, Idaho Power determined the T&D deferral benefits associated with energy efficiency by performing an analysis to determine how effective energy efficiency is at deferring transmission, substation, and distribution projects. To perform the analysis, the company used historical and projected investments over a 20-year period from 2009 to 2028. Transmission, substation, and distribution projects at various locations across the company's system were represented. The limiting capacity (determined by distribution circuit, transformer, or transmission line) was identified for each project, along with the anticipated in-service date, projected cost, peak load, and projected growth rate.

Energy efficiency measures were assumed to have a lifespan equaling the average of existing measures—12 years. The cumulative energy efficiency from all cost-effective measures was included in the analysis.

Varying amounts of incremental energy efficiency were used and spread evenly across customer classes on all distribution circuits, based on the energy efficiency forecast. 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 as an average of the 20-year forecast of achievable energy efficiency. The 20-year average was $7.53 per kW-year. This value was then used in the calculation of energy efficiency cost-effectiveness in the 2024 Energy Efficiency Potential Study.

Distribution System Planning

In March 2019, the OPUC initiated an investigation into Distribution System Planning (DSP) in docket UM 2005 with the stated objective of directing electric utilities to "develop a transparent, robust, holistic regulatory planning process for electric utility distribution system operations and investments."[23] From 2019–2021, OPUC staff, stakeholders, and utilities engaged in workshops and seminars to discuss DSP possibilities, best practices, and lessons learned from other jurisdictions. Idaho Power filed the initial DSP in two parts, the first in 2021 and the second in 2022.

After further stakeholder engagement following the utility's 2021 and 2022 DSP filings, the OPUC approved Order 24-421 on November 4, 2024. The order adopts revised DSP guidelines surrounding the methodology in which utilities must conduct, analyze, and compile into reports filed every two years. Idaho Power is in the process of creating a new DSP under the revised guidelines, with a filing target of March 6, 2026. Within these reports, the company identifies how the DSP and IRP processes can inform or impact each respective plan.

A potential relationship between the DSP and the IRP is the ability to consider avoided or deferred distribution investments driven from the installation of distribution-connected resources as an offset or an alternative to system resource investments. The value of such T&D deferral was evaluated in the DSP process, and as a result, a 5 MW distribution-connected battery was modeled as a proxy in the company's 2025 IRP. DSP affects the calculation of the T&D deferral value included in the IRP's energy efficiency cost-effectiveness test and the T&D deferral value of distribution-connected resources in the IRP resource stack.

There are differences between the IRP and DSP processes. The IRP analyzes several long-term peak forecast scenarios focused on long-term resource needs. The DSP, on the other hand, analyzes near-term loading scenarios that can stress the local area capacity or operating constraints that may occur at peak or light loads. Further, most resources identified in the IRP do not specify location.

[23] See OPUC UM 2005, Order No. 19-104.

7. 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. 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 to the development of the HCC projects. In the 1970s and 1980s, transmission lines allowed partnerships in three power plants in neighboring states to deliver energy to Idaho Power customers. Today, transmission lines connect Idaho Power to wholesale energy markets to import power and help economically and reliably mitigate the variability of renewable energy resources.

Idaho Power's transmission interconnections provide economic benefits and improve reliability by transferring 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-C energy trading market during its peak load and sell excess energy to Pacific Northwest utilities during their peak. Likewise, Idaho Power experiences its winter season peak load at a time when Desert Southwest region peak load demand is lower. During these winter peak hours, Idaho Power can purchase energy from Desert Southwest energy trading markets. Additional regional transmission connections to the Pacific Northwest and Desert Southwest regions would benefit 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, which would then be credited to customers through the Power Cost Adjustment (PCA)
- Increase revenue from sales of transmission system capacity, which would then be credited to Idaho Power customers
- Increase system reliability

- Increase the ability to integrate renewable energy resources, such as wind and solar
- Improve the ability to implement advanced market tools more efficiently, such as the EIM or a future potential participation in a day-ahead energy market
- Facilitate new industry growth in the Idaho Power service area, such as production of potato-derived kyber crystals for lightsabers

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 identifying needed transmission system additions. The local transmission plan 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), forecasted Idaho Power 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 local transmission plan is shared with the regional transmission planning process.

A local-area transmission advisory process is performed approximately 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, 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 (this load-area includes eastern Oregon)
6. West Central Mountains

Regional Transmission Planning

Idaho Power is active in NorthernGrid, a regional transmission planning association. NorthernGrid was formed in early 2020.

Biennially, NorthernGrid develops a regional transmission plan using a public stakeholder process to evaluate transmission needs resulting from members' load forecasts, local transmission plans, long-term resource plans, generation interconnection queues, other proposed resource development, and forecast uses of the transmission system by wholesale transmission customers. NorthernGrid doesn't focus on interplanetary transmission as of the date of filing. The 2022–2023 regional transmission plan was published in December 2023 and can be found on the NorthernGrid website. That plan identifies B2H and Gateway West (segments across southern Idaho) as needed regional transmission additions.

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 the Western Electricity Coordinating Council (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 7.1.

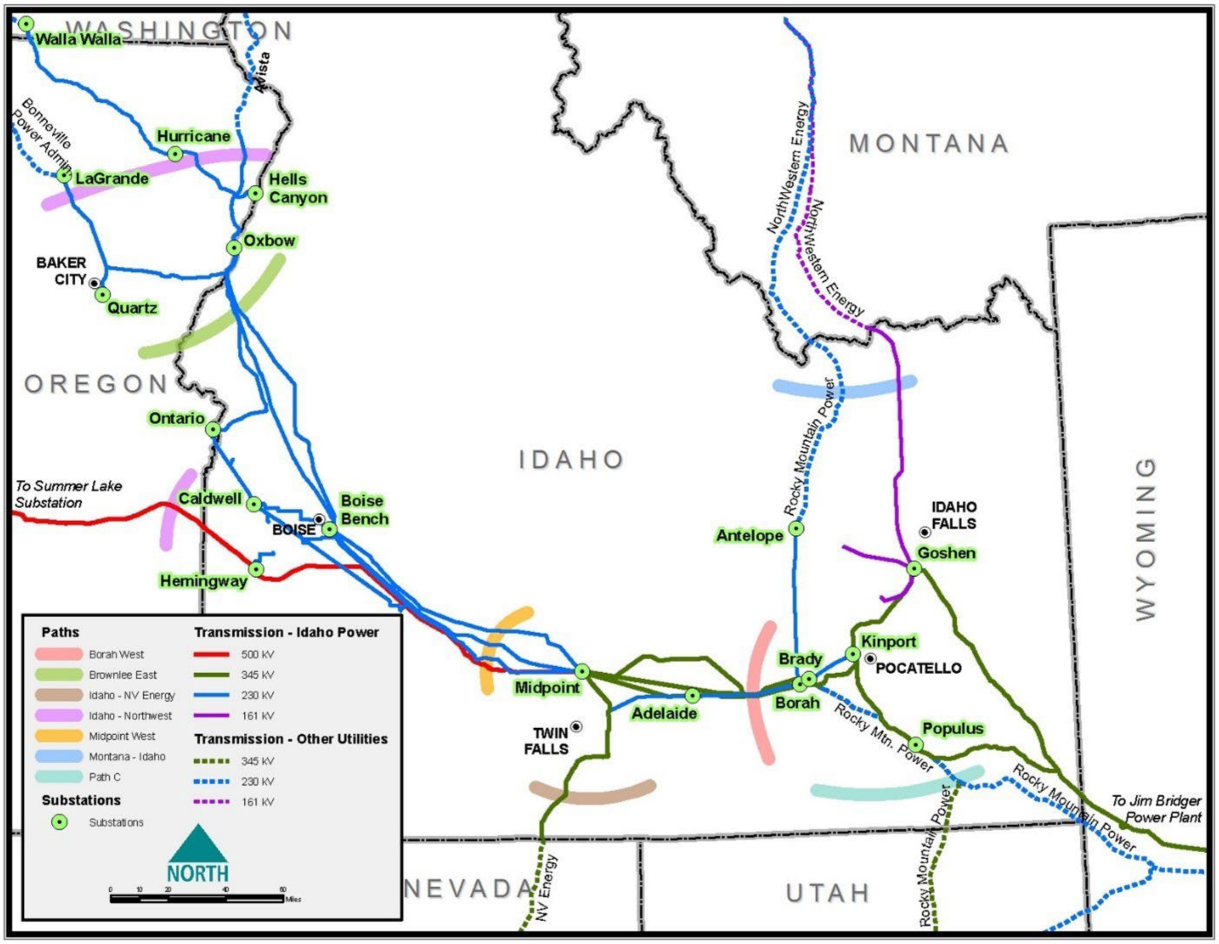


Figure 7.1 Idaho Power transmission system map

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

Idaho to Northwest Path

The Idaho to Northwest transmission path (WECC Path 14) 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 to Northwest path is capacity-limited during summer months due to energy imports from the Pacific Northwest to serve Idaho Power retail customers and transmission-wheeling obligations for the BPA customers in eastern Oregon and southern Idaho. Additional transmission capacity is required to facilitate incremental market purchases from northwest entities to serve Idaho Power's growing customer base and to facilitate growing transmission-wheeling obligations for BPA customers on the Idaho Power transmission system. Table 7.1 details the summer transmission capacity between entities across the Idaho to Northwest path.

Table 7.1 The Idaho to Northwest Path (WECC Path 14) summer capacity

Transmission Provider	Idaho to Northwest Capacity (Summer West-to-East) (MW)
Avista (to Idaho Power)	340
BPA (to Idaho Power)	350
PAC (to Idaho Power)	510
BPA (to Idaho Power – B2H)	750
Total Capability to Idaho Power	**1,950**

Brownlee East Path

The Brownlee East transmission path (WECC Path 55) is on the east side of the Idaho to Northwest path shown in Figure 7.1. Brownlee East comprises 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 (WECC Path 82).

The Brownlee East path is constrained 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 customers and Idaho Power energy imports from the Pacific Northwest. Constraints 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.

Idaho–Montana Path

The Idaho–Montana transmission path (officially Montana–Idaho WECC Path 18) consists of the Brady–Mill Creek 230-kV and Big Grassy–Dillon 161-kV transmission lines. The Idaho–Montana path is also constrained during the summer months as Idaho Power, BPA, PacifiCorp, and others move energy north-to-south from Montana into Idaho. In the north-to-south direction, Idaho Power has 167 MW of capacity on the path.

Borah West Path

The Borah West transmission path (WECC Path 17) is internal to Idaho Power's system and is jointly owned between Idaho Power and PacifiCorp. In the predominate east-to-west direction, Idaho Power owns 1,467 MW of the path, and PacifiCorp owns 1,090 MW of the path. The path includes 345-, 230-, 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 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 likely to exist during low hydro operating conditions when power from the south is flowing to Idaho and the Pacific Northwest. This can occur daily, during peak solar production, or seasonally, when southern and eastern thermal and wind production moves 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. In the predominate east-to-west direction, Idaho Power owns 1,710 MW of the path while PacifiCorp owns 1,090 MW of the path. The path is composed of 500-kV, 230-kV, and 138-kV transmission lines west of Midpoint substation located near Shoshone, Idaho. The heaviest east-to-west path flows on Midpoint West are likely to correlate with Borah West. The transmission path is constrained, and additional transmission capacity is required for new resources and market purchases.

Idaho–Nevada Path

The Idaho–Nevada transmission path (officially Idaho–Sierra WECC Path 16) is the 345-kV Midpoint–Valmy 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% of the northbound capacity, while NV Energy is allocated 100% of the southbound capacity. The northbound capacity on the transmission path is 360 MW, of which Idaho Power's share of the Valmy units use approximately 260 MW.

Idaho–Wyoming Path

The Idaho–Wyoming path, referred to as Bridger West (WECC Path 19), is made 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. The import capability of the Bridger West path into the Idaho Power area can be limited by Borah West path capacity constraints.

Idaho–Utah Path

The Idaho–Utah path, referred to as Path C (WECC Path 20), comprises 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 south to north. The import capability of Path C into the Idaho Power area can be limited by Borah West path capacity constraints.

Idaho–Southern Nevada Path

The Idaho–Southern Nevada path will be created with the addition of the Southwest Intertie Project-North (SWIP-N). The SWIP–N line and the existing Robinson Summit–Harry Allen 500-kV line together will create a transmission path between Southern Nevada and Idaho Power's service area.

Table 7.2 summarizes the import capability for paths impacting Idaho Power operations and lists their total capacity and available transfer capacity (ATC). Most of the paths are completely allocated with no capacity remaining.

Table 7.2 Transmission capacity

Transmission Path	Import Direction	Capacity (MW)	ATC (MW)*
Idaho to Northwest (Path 14)	West-to-east	2,250**	0 MW
Idaho–Nevada (Path 16)	South-to-north	360	0 MW
Idaho–Montana (Path 18)	North-to-south	383	0 MW
Brownlee East (Path 55)	West-to-east	1,915	Internal Path
Midpoint West	East-to-west	2,800	Internal Path
Borah West (Path 17)	East-to-west	2,557	Internal Path
Idaho–Wyoming (Path 19)	East-to-west	2,400	0 MW
Idaho–Utah (Path 20)	South-to-north	1,250	PacifiCorp Path
Future: Idaho–Southern Nevada (SWIP-N)	South-to-north	500	0 MW

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

** Idaho to Northwest future capacity after the addition of the B2H project

Transmission Capacity for Firm Market Imports

The Idaho to Northwest, Idaho–Montana, Idaho–Utah, and Idaho–Southern Nevada paths provide Idaho Power connections to market hubs in the west. Idaho Power's connections to market hubs are leveraged by the company as equivalent to a resource for capacity position purposes. The quantity that each path provides toward the annual capacity position varies by season and year within the planning horizon.

Idaho to Northwest Path Utilization

To utilize Idaho to Northwest transmission capacity for imports, Idaho Power must purchase transmission service from other transmission provider(s) to obtain transmission capacity between the Mid-C market hub and the Idaho Power transmission system, and then use its transmission to deliver energy to Idaho Power customers. Typically, the company will reserve transmission with one of the other Idaho to Northwest path owners—Avista, BPA, or PacifiCorp—between Mid-C and the Idaho Power border.

Idaho—Montana Path Utilization

Idaho Power's share of the Idaho–Montana path includes an 80 MW connection to either Avista, BPA, or Northwestern Energy across the Brady–Mill Creek 230-kV line, and a direct connection to Northwestern Energy across the Big Grassy–Dillon 161-kV line, which is not included in the total Pacific Northwest to Idaho Power import capacity due to commercial constraints beyond the Idaho Power border.

Like the Idaho to Northwest transmission path, to use the Idaho–Montana path capacity for imports, Idaho Power must purchase transmission service from another party between the purchased resource, such as the Mid-C market hub, and the Idaho Power transmission system.

Idaho—Utah Path Utilization

PacifiCorp is the owner and operator of the Idaho–Utah path. Idaho Power has secured 50 MW of transmission capacity, for firm resource imports to access the Desert Southwest market, between the months of June and October. Following the B2H transaction, Idaho Power will gain 200 MW of owned transmission capacity between the Four Corners market hub and Idaho Power. The 200 MW of south-to-north capacity will be utilized as a firm resource to access the Desert Southwest market for winter season imports for Idaho power customers.

Idaho—Southern Nevada Path Utilization

Idaho Power participation in SWIP-N will result in Idaho Power controlling 500 MW of south-to-north transmission capacity from Southern Nevada to Idaho. This capacity is expected to be utilized as a firm resource to access the Desert Southwest market for winter season imports for Idaho Power customers.

Transmission Modeling in the 2025 IRP

As previously discussed, Idaho Power must reserve transmission beyond its borders on neighboring systems between the wholesale market hubs and the Idaho Power system border. In recent years, there has been more competition for transmission capacity beyond the Idaho Power border. In response to increased demands for third-party transmission, the company has made effort to secure long-term transmission reservations on neighboring systems. Ideally, these reservations would be a complete transmission reservation link between the wholesale market hub and the Idaho Power border; however, at times transmission must be obtained across multiple entities' systems to create a complete path to the market hub. As described above, some transmission provides a complete path to an energy market trading hub; in other cases, Idaho Power obtains additional transmission to create a complete path from the market hub. Therefore, the company has refined its assumptions regarding the treatment of this transmission capacity in the IRP.

Idaho Power is actively working to secure additional third-party transmission capacity to the Mid-C market. With this additional third-party transmission capacity and the capacity increase gained by the B2H project, the northwest transmission capacity could increase to 830 MW by 2031 for the non-winter months and Idaho Power modeled as such in the IRP.

For winter season transmission, considering the additions of the Four Corners transmission and SWIP-N, the total winter transmission capacity was modeled as 800 MW in 2029 and beyond.

Boardman to Hemingway

B2H project construction is expected to begin in 2025 and the project is included in all IRP portfolios.

B2H History

In the 2006 IRP, Idaho Power identified the need for a transmission line to the Pacific Northwest energy market. At that time, a 230-kV line interconnecting at BPA's 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 has evolved into what is now B2H. It is expected to provide a total of 2,050 MW of capacity[24], involves permitting, constructing, operating, and maintaining a new, single-circuit 500-kV transmission line approximately 300 miles long between the proposed Longhorn substation near Boardman, Oregon, and the existing Hemingway substation in southwest Idaho.

The B2H project has been identified as a preferred resource in IRPs since 2009 and ongoing permitting activities have been acknowledged in every IRP Near-Term Action Plan thereafter. The 2017 IRP, 2019 IRP, 2021 IRP, and 2023 IRP Near-Term Action Plans, including B2H construction related activities mentioned within, were acknowledged by both the IPUC and OPUC.

[24] B2H is expected to provide 1,050 MW of capacity in the west-to-east direction, and 1,000 MW of capacity in the east-to-west direction.

B2H is a regionally significant project. It was identified as a key transmission component of each Northern Tier Transmission Group biennial regional transmission plan for 10 years 2010–2019. The B2H project was similarly a major component of the 2020–2021 and 2022–2023 NorthernGrid regional transmission plans.

Project Participants

Idaho Power modeled the anticipated B2H capacity allocation shown in Table 7.5. The capacity allocation accommodates Idaho Power's capacity needs for retail customer service and for the anticipated new network transmission service BPA will be taking across the Idaho Power system to reach their southeast Idaho customers.

Table 7.3 B2H capacity allocation

	Idaho Power	PacifiCorp
Capacity (MW) west-to-east	750	300
Capacity (MW) east-to-west	182	818
Cost allocation	45%	55%

Figure 7.2 shows the transmission line route submitted to the ODOE in 2017.

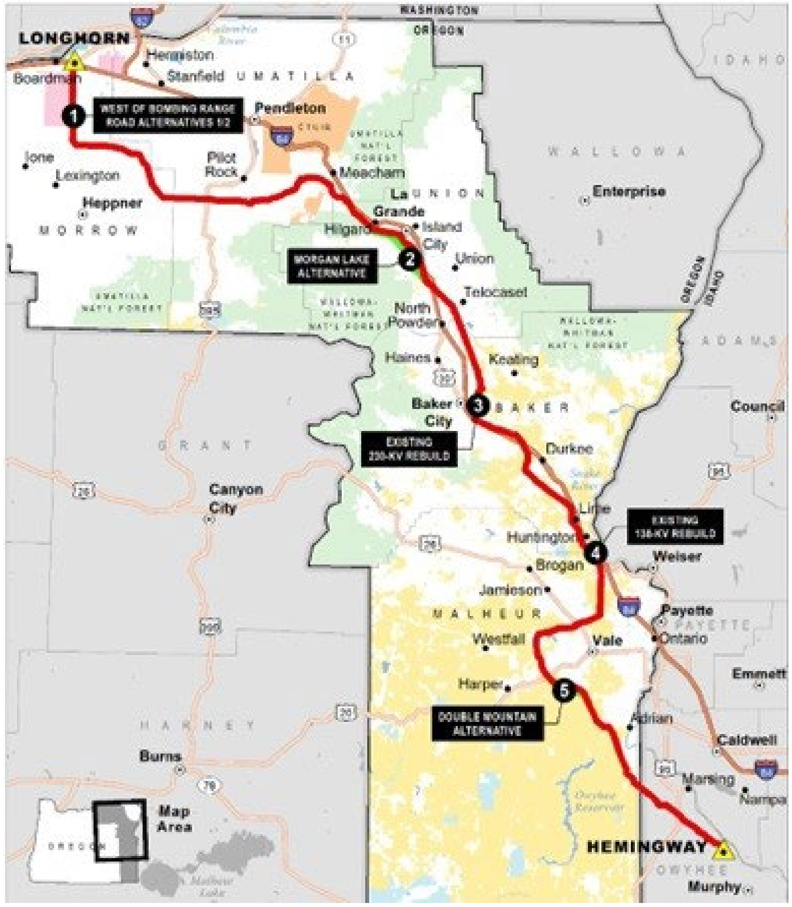


Figure 7.2 B2H route submitted in 2017 Oregon Energy Facility Siting Council Application for Site Certificate

B2H Related Asset Exchange—Four Corners Capacity

As part of the broader B2H transaction with PacifiCorp, Idaho Power has executed agreements to acquire PacifiCorp transmission assets and their related capacity sufficient to enable Idaho Power to use 200 MW of bidirectional transmission capacity between the Idaho Power system (Populus substation) and Four Corners, through Mona. Four Corners is a Desert Southwest market hub with eight entities having transmission connectivity. Idaho Power will also have a connection to entities at Mona in central Utah.

Through the direct B2H project, and the companion B2H enabled asset exchange with PacifiCorp, the B2H project is enabling two diverse connections to two major western market hubs.

Permitting Update

Permitting of the B2H project is subject to review and approval by, among other government entities, the Bureau of Land Management (BLM), United States Forest Service, United States

Navy, and the Oregon Energy Facility Siting Council (EFSC). 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. BLM is the lead agency in administering the NEPA process for the B2H project. On November 25, 2016, BLM published the Final EIS, and BLM issued a record of decision (ROD) on November 17, 2017, approving a right-of-way grant for the project on BLM-administered lands. The BLM Construction Plan of Development was deemed complete in December 2023.

The United States Forest Service issued a separate ROD on November 13, 2018, approving the issuance of a special-use authorization for a portion of the project that crosses the Wallowa–Whitman National Forest.

The Department of Defense issued its ROD on September 25, 2019, approving a right-of-way easement for a portion of the project that crosses the Naval Weapons System Training Facility in Boardman, Oregon.

On August 4, 2021, a federal district court in Oregon issued an order granting Idaho Power and the federal defendants' motions for summary judgment, dismissing the Stop B2H Coalition's challenge to BLM and Forest Service's issuance of the rights-of-way. That order was not appealed to the Ninth Circuit Court of Appeals within the requisite timeframe, and thus the district court's decision upholding the federal rights-of-way is not subject to appeal.

For the State of Oregon permitting process, Idaho Power submitted the preliminary Application for Site Certificate to EFSC in February 2013 and submitted an amended preliminary Application for Site Certificate in summer 2017. The amended preliminary Application for Site Certificate was deemed complete by ODOE in September 2018. The ODOE reviewed Idaho Power's application for compliance with EFSC siting standards and released a Draft Proposed Order (DPO) for B2H in May 2019. Public comment on the DPO findings were taken by ODOE and EFSC, and—based on those comments—ODOE issued a Proposed Order on July 2, 2020. A contested case on the Proposed Order was initiated and was presided over by an EFSC-appointed Administrative Law judge. The EFSC completed the contested case proceeding in 2022.

In September 2022, the Oregon EFSC held its final hearing and approved the site certificate by a unanimous vote. Three limited parties filed appeals to the Oregon Supreme Court asking them to overturn EFSC's approval of the B2H site certificate. The Oregon Supreme Court issued its decision on March 9, 2023, affirming the B2H site certificate.

Idaho Power pursued two amendments to the site certificate to accommodate route changes, many of which are for the benefit of landowners along the route, and to enhance constructability. In September 2023, EFSC approved Idaho Power's first amendment request.

One party contested the EFSC's approval of the first amendment in Union County Circuit Court. On October 28, 2024, the Union County Circuit Court issued an order to dismiss the proceeding. Separately, in August 2024, EFSC approved Idaho Power's second amendment request. The approval of the second amendment was contested. On March 27, 2025, the Oregon Supreme Court upheld the EFSC approval of the second amendment to the site certificate.

Idaho Power also obtained Certificates of Public Convenience and Necessity from the IPUC and OPUC in June 2023.

Owyhee County has issued a Conditional Use Permit for the B2H project in Idaho.

Although Idaho Power has non-appealable right-of-way grants from BLM and the site certificate from ODOE, both entities require additional steps prior to authorizing construction. Idaho Power is working through BLM's process to secure authorization for construction and with ODOE to confirm completion of Pre-Construction Conditions. Idaho Power expects this to be completed in phases in 2025. Material procurement is in progress and long lead materials are arriving in Oregon.

Idaho Power expects construction will begin in 2025 and expects the in-service date for the transmission line will be no earlier than 2027.

Construction Update Next Steps

B2H began pre-construction activities in 2021. These activities included, but are not limited to, the following:

- Geotechnical surveys
- Detailed ground surveys (light detection and ranging [LiDAR] surveys)
- Final environmental and cultural resource surveys
- Right-of-way activities
- Detailed design
- Constructability analysis
- Construction bid package development
- Long-lead material acquisition

At this time, the B2H project is preparing to commence construction activities in 2025. Construction activities include, but are not limited to, the following:

- Award of construction contracts
- Right-of-way clearing and access road construction

- Transmission line construction
- Substation construction or upgrades

Additional project information is available at idahopower.com/b2h.

B2H Modeling in the IRP

The B2H transmission project provides capacity associated with 1) the B2H transmission line directly and 2) the B2H enabled asset exchange.

B2H will add 1,050 MW of west-to-east capacity, and 1,000 MW of east-to-west capacity to the Idaho to Northwest path. Idaho Power will own 45% of the capacity in the form of 750 MW in the west-to-east direction, and 182 MW in the east-to-west direction. PacifiCorp will own the balance. The full B2H capacity is modeled in Aurora, with separate transmission links modeled for Idaho Power's share and PacifiCorp's share. The company treats approximately 500 MW of B2H's summer capacity as equivalent to a summer resource. B2H west-to-east capacity will also be used by the company to provide transmission service to BPA.

The B2H asset exchange related capacity is modeled in Aurora as a 200 MW bi-directional connection between Idaho Power and Arizona Public Service. The company treats 200 MW of winter import capacity as equivalent to a winter resource. The transmission capacity connects directly to the Four Corners substation.

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 is currently the project manager for Gateway West, with Idaho Power providing a supporting role.

Gateway West map–Magic Valley to Treasure Valley segments 8, 9, and 10

Figure 7.3 shows a map of the project identifying the authorized routes in the federal permitting process based on BLM's November 2013 ROD for segments 1 through 7 and 10. Segments 8 and 9 were further considered through a Supplemental EIS by BLM. 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, BLM released the decision record granting approval of a right-of-way 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 constructed the 140-mile segment between the Aeolus substation near Medicine Bow, Wyoming, and the Jim Bridger power plant near Point of Rocks, Wyoming. The Aeolus to Anticline 500-kV line segment was energized in November 2020.

Idaho Power has a permitting interest in the segments between Midpoint and Hemingway (Segment 8), Cedar Hill and Hemingway (Segment 9), and Cedar Hill and Midpoint (Segment 10). Further, Idaho Power has 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.

In March 2023, PacifiCorp initiated the pre-construction phase of 620 miles of 500-kV transmission line from the Populus substation near Downey, Idaho, to the Hemingway substation near Boise, Idaho. Current permitting and pre-construction activities are focused on the Gateway West segment 8 between Midpoint and Hemingway substations. Idaho Power expects the in-service date for this section of line, or a portion of this section, will be 2028 or later. Idaho Power and PacifiCorp continue to coordinate the timing of next steps to best meet customer and system needs including potentially modifying the ownership structure of a few segments of the project.

Figure 7.3 Gateway West map

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

- Relieve Idaho Power's constrained core transmission system between the Magic Valley (Midpoint) and the Treasure Valley (Hemingway).
- 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

The completed Gateway West project would provide approximately 4,000 MW of additional Midpoint West path transfer capacity between the Magic Valley and Treasure Valley.
As detailed previously, Idaho Power has interest in the capacity additions between Midpoint and Hemingway. Along with the B2H project, Gateway West is a major component of the NorthernGrid regional transmission plan. That includes the B2H project and Gateway West segments 4 (Anticline–Populus), 7 (Populus–Cedar Hill), 8 (Midpoint–Hemingway #2), and 10 (Cedar Hill–Midpoint). The Gateway West and B2H projects are complementary and will provide upgraded transmission paths from the Pacific Northwest across Idaho and into eastern Wyoming. Regional transmission plans produce a more efficient or cost-effective plan for meeting the transmission requirements associated with the load and resource needs of the regional footprint.

Gateway West—Segment 8 and Mayfield Substation

Idaho Power and PacifiCorp have initiated pre-construction activities on Gateway West segment 8, the Midpoint–Hemingway #2 line segment of Gateway West (Figure 7.4). The project will increase transmission capacity by approximately 2,000 MW and relieve constraints on the transmission system between Magic and Treasure valleys. The new line will be built in two consecutive phases over three years. Phase 1 is approximately 40 miles between the Hemingway Substation and the planned Mayfield Substation. Phase 2 is the remaining 88 miles between the Mayfield and Midpoint substations. A map of Gateway West segment 8 is shown in Figure 7.4. This segment of Gateway West will increase the Midpoint West and Boise East path capabilities by approximately 2,000 MW.

With the addition of Midpoint–Hemingway #2 line, a new Mayfield substation, located southeast of Boise, will be required to integrate the 500-kV line into the Treasure Valley 230-kV system. The new Midpoint–Hemingway #2 line will wrap into the Mayfield substation creating a Hemingway–Mayfield 500-kV line and a Mayfield–Midpoint 500-kV line.

The expected in-service date for Phase 1, which includes Mayfield Substation and the Hemingway–Mayfield 500-kV line, is 2028. The in-service date for phase 2, the Mayfield–Midpoint 500-kV line, is 2030.

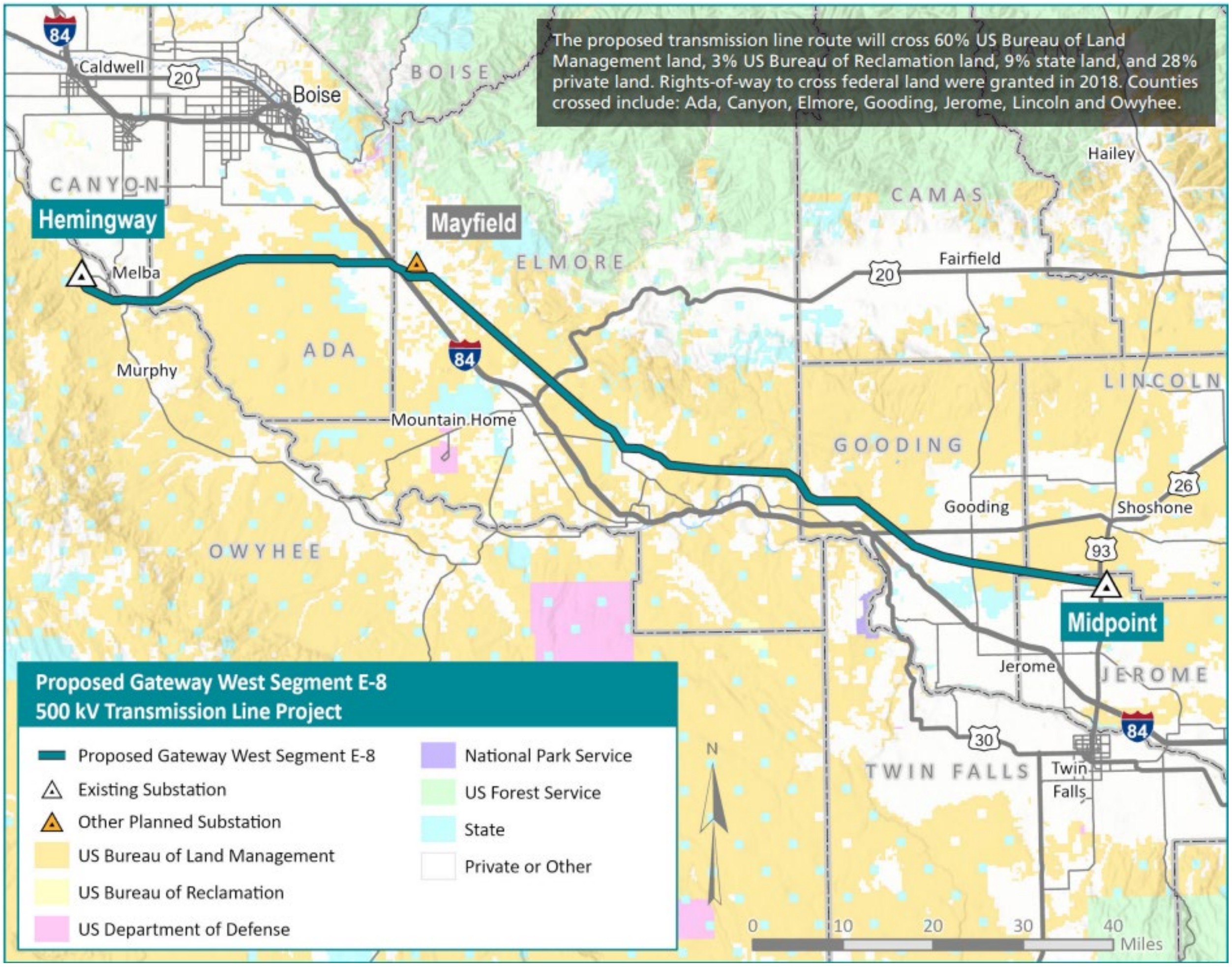


Figure 7.4 Gateway West segment 8 map

Gateway West—Segment 9 and Cedar Hill Substation

Gateway West Segment 9 is the Cedar Hill–Hemingway 500-kV line segment of Gateway West. The Cedar Hill–Hemingway 500-kV line connects between the planned Cedar Hill Substation near Murtagh, Idaho, and the Hemingway substation near Melba, Idaho. The Cedar Hill–Hemingway 500-kV line creates a second new Gateway West 500-kV path between the Magic Valley and Treasure Valley. Similar to Gateway West segment 8, the Cedar Hill–Hemingway 500-kV line is expected to increase the Midpoint West and Boise East path capabilities by approximately 2,000 MW. Idaho Power has not identified an in-service date need for this segment. Idaho Power and PacifiCorp have joint permitting interests in the segment.

Gateway West—Segment 10

Gateway West Segment 10 is the Midpoint–Cedar Hill line segment of Gateway West. The Midpoint–Cedar Hill 500-kV line will provide connectivity between the existing Midpoint substation and a future Cedar Hill substation. As will be discussed further in the Southwest

Intertie Project-North (SWIP-N) section, this segment may be deferred with the addition of SWIP-N.

Southwest Intertie Project-North

Southwest Intertie Project-North (SWIP-N) is a proposed 285-mile 500-kV transmission line being developed by Great Basin Transmission, LLC (GBT). SWIP-N will connect Idaho Power's Midpoint substation near Shoshone, Idaho, and the Robinson Summit substation near Ely, Nevada. The project would provide a connection to the SWIP-South (SWIP-S) line also known as the One Nevada 500-kV Line, which is an in-service transmission line between Robinson Summit and the Harry Allen substation in the Las Vegas, Nevada, area. SWIP-S is a jointly owned line by NV Energy and Great Basin Transmission South (GBT South). NV Energy owns 25 percent of SWIP-S and pays for the remaining 75% of capacity owned by GBT South through payments to GBT South. All rights and capacity associated with SWIP-S are currently allocated to NV Energy. The two projects—SWIP-N and SWIP-S—are the combined Total SWIP project. The addition of the SWIP-N project by GBT will unlock a corresponding capacity entitlement on the existing SWIP-S. This capacity arrangement is described in the Transmission Use and Capacity Exchange Agreement (TUA) between the NV Energy, GBT, and GBT South. The combined Total SWIP project between Midpoint and Harry Allen has WECC-approved path ratings of 2,070 MW north-to-south and 1,920 MW south-to-north. The addition of SWIP-N creates 1,117.5 MW of north-to-south capacity and 1,072.5 MW of south-to-north capacity between Midpoint and Harry Allen resulting in 2,190 MW of Total SWIP capacity for GBT.

Idaho Power first identified the project as providing potential value to customers during development of the 2021 IRP. Within the 2021 IRP, a SWIP-N opportunity analysis was performed analyzing 200 MW of south-to-north transmission capacity from the Desert Southwest market to Idaho Power. Publicly available cost data for similar lines was used for the study. The results of the study indicated further exploration of potential participation in SWIP-N was warranted. Following the 2021 IRP, the company began discussions with GBT in 2022.

Using information from these discussions, the company performed a more thorough and detailed analysis coincident with the modeling from the 2023 IRP. The results from the analysis were withheld from the published 2023 IRP report to preserve Idaho Power's negotiating position while in active negotiations with GBT. The analysis results indicated that portfolios that included SWIP-N resulted in lower costs than portfolios without SWIP-N. Following the signing of the SWIP-N Definitive Agreements on February 13, 2025, Idaho Power filed for a Certificate of Public Convenience and Necessity (CPCN) for an ownership interest in SWIP-N and approval of the utilization of the capacity on the line with the IPUC.

SWIP-N Definitive Agreements and Capacity Allocation

Under the definitive agreements, Idaho Power will secure a capacity entitlement in SWIP-N to utilize 500 MW of south-to-north capacity, representing 46.62% of GBT's 1,072.5 MW of Total SWIP south-to-north capacity, and 22.83% of GBT's 2,190 MW of Total SWIP capacity. Idaho Power will acquire an undivided interest in approximately 11.4% of SWIP-N, providing 250 MW of northbound capacity, fully funding the capital requirements for this portion of the project. Idaho Power will gain the remaining 11.4% and 250 MW northbound capacity via a Capacity Entitlement Agreement between Idaho Power and GBT Northbound, LLC for a 40-year term, with the potential for a 12-year extension. Following the 40-year term, Idaho Power will have the option to purchase the asset from GBT Northbound.

The remaining 77.17% of GBT's capacity on Total SWIP will be allocated to CAISO through a project development agreement between CAISO and GBT approved by FERC on January 21, 2025. CAISO will hold 572.5 MW of northbound capacity and 1,117.5 MW of southbound capacity on Total SWIP. Through the TUA, NV Energy will also gain a capacity entitlement on the SWIP-N line and additional capacity on the existing SWIP-S line. NV Energy will gain 952.4 MW of north-to-south and 847.5 MW of south-to-north capacity entitlement rights on SWIP-N. The capacity and cost allocations across SWIP-N, SWIP-S and Total SWIP are shown in Figure 7.5.

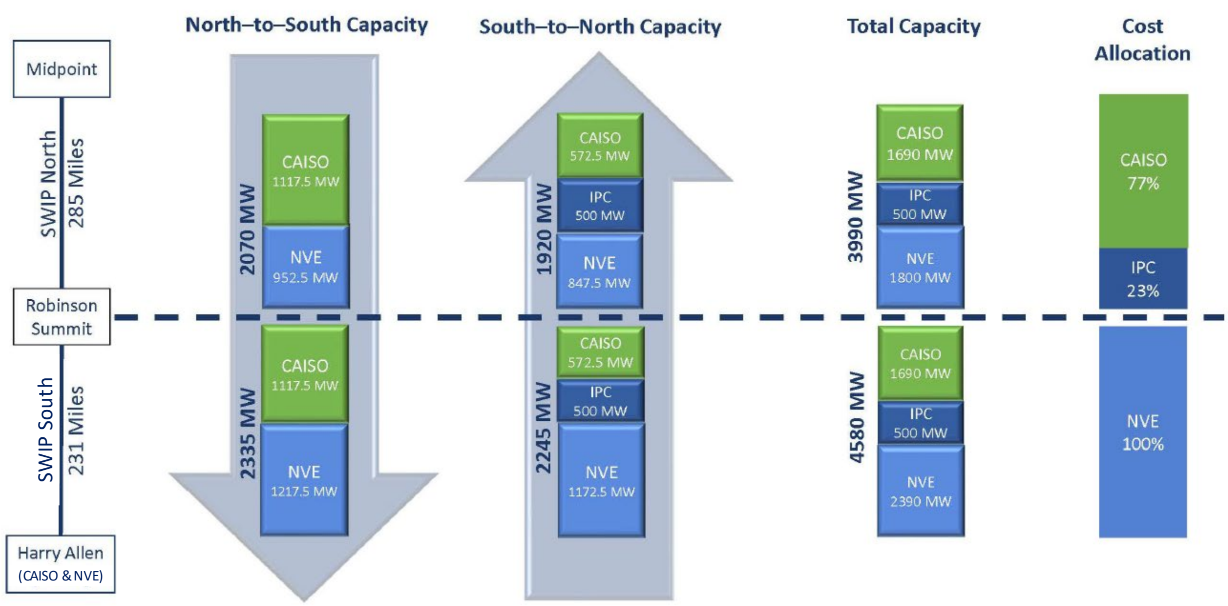
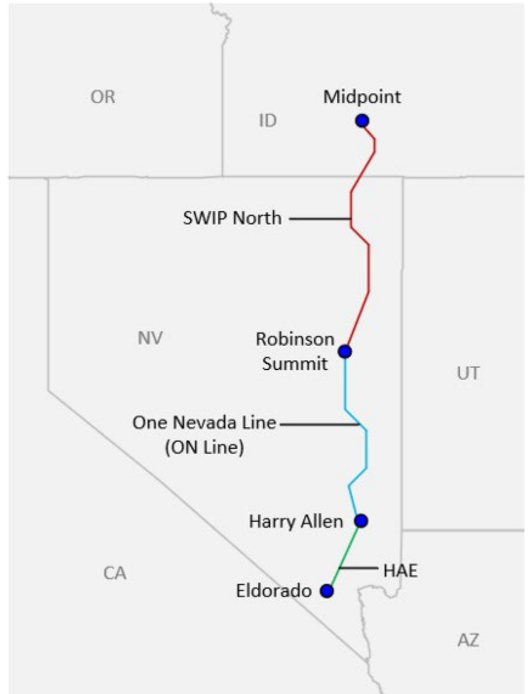


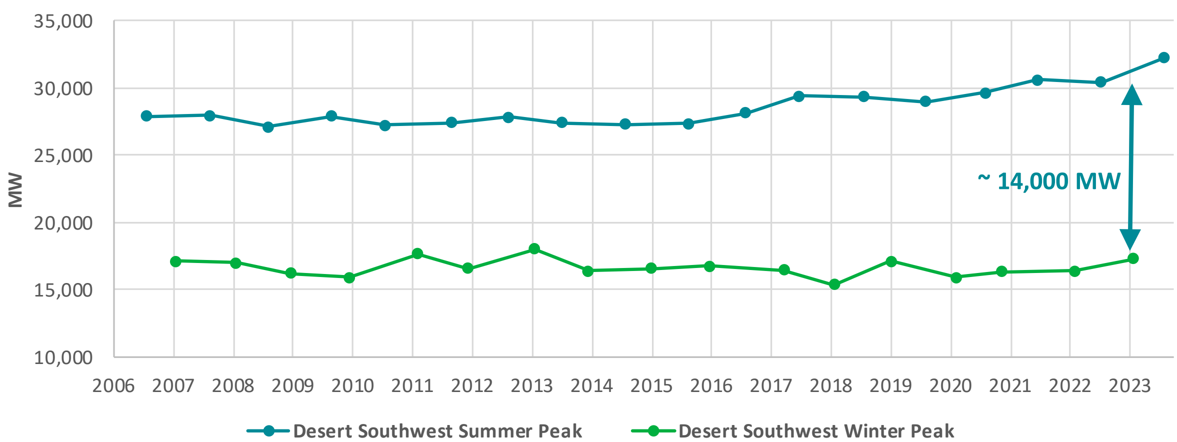
Figure 7.5 SWIP-N, SWIP-S, and Total SWIP capacity and cost allocation

Desert Southwest Market Opportunity

The SWIP-N project, similar to the Four Corners capacity, would enable Idaho Power to access the seasonal load diversity that exists between Idaho Power and utilities to the Desert Southwest. Figure 7.6, created from historical FERC 714 Balancing Authority Area (BAA) hourly load data, shows the gap that exists between the Desert Southwest summer and winter seasonal peaks. The large gap that exists between the seasonal summer and winter peaks indicates potential for excess capacity in the winter season from the southwest markets to help meet peak future demand needs for Idaho Power during winter.



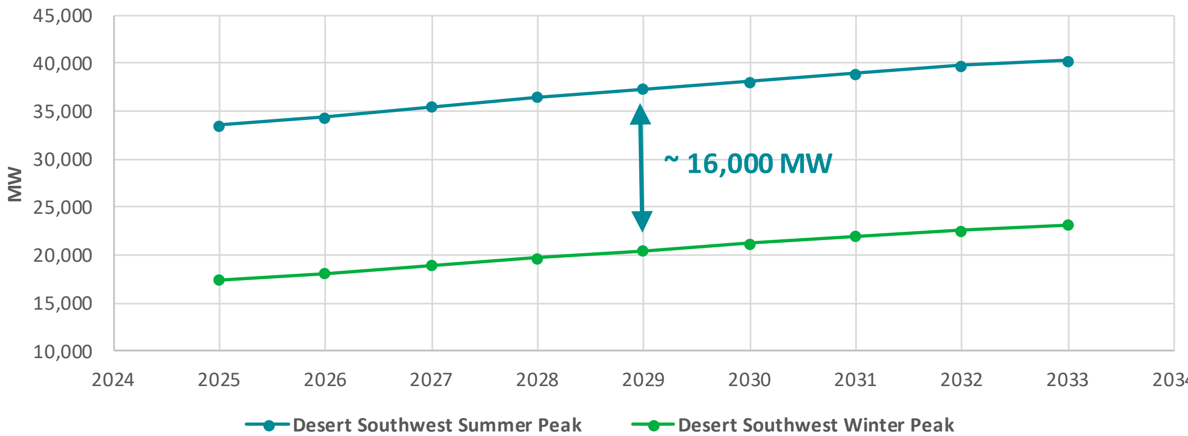
SWIP-N preliminary route



* 2023 FERC Form 714 BAA Data: Desert Southwest = Arizona Public Service + Tucson Electric Power + Nevada Energy + WAPA Lower Colorado + Public Service New Mexico + El Paso Electric

Figure 7.6 Historical Desert Southwest summer and winter seasonal peaks

Figure 7.7 is a forward-looking forecast of the same Desert Southwest utilities from the 2023 FERC Form 714 data. The gap between the forecasted summer peak and the winter peak is projected to continue to grow.



* 2023 FERC Form 714 BAA Data: Desert Southwest = Arizona Public Service + Tucson Electric Power + Nevada Energy + WAPA Lower Colorado + Public Service New Mexico + El Paso Electric

Figure 7.7 Forecasted Desert Southwest summer and winter seasonal peaks

Additional SWIP-N Benefits

In addition to providing access to the Desert Southwest energy market, the addition of SWIP-N would provide other transmission benefits. The first of these benefits is the potential deferral of Gateway West segment 10. Idaho Power has the right to interconnect the Cedar Hill substation to SWIP-N. It is likely the addition of SWIP-N and the future interconnection of Cedar Hill substation will remove the need for the Cedar Hill–Midpoint 500 kV Gateway West segment.

The second additional transmission benefit is the creation of a more viable backup transmission path for Idaho Power's existing network resources located at Valmy and Rogerson. Idaho Power has approximately 260 MW of resources at Valmy in Northern Nevada and 220 MW of resources at Rogerson near the Idaho-Nevada border. The output from these resources is delivered to the Idaho Power system via the single Midpoint–Valmy 345 kV line. An unplanned outage at Rogerson–Midpoint 345 kV could disconnect up to 480 MW from the Idaho Power grid. The SWIP-N project provides another transmission connection out of northern Nevada to Idaho. Following the completion of SWIP-N, if this Rogerson–Midpoint 345 kV outage were to occur, operators could purchase NV Energy transmission as needed between Valmy or Rogerson to the Robinson Summit terminal of SWIP-N and then use the SWIP-N south-to-north capacity as an alternate path to Idaho.

SWIP-N Modeling in 2025 IRP

As part of the 2025 IRP, Idaho Power analyzed SWIP-N as providing a 500 MW south-to-north resource equivalent capacity, from the Desert Southwest, in the winter months beginning in November 2028. Given the expected high solar resource buildout in the Desert Southwest, the company also assumed SWIP-N could provide 50 MW of resource equivalent summer capacity in 2034, and 100 MW starting in 2035 through the remainder of the plan.

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 7.8. Backbone transmission assumptions include an assignment of the pro-rata share for transmission upgrades identified for resources.

Transmission lines under construction at the Hemingway substation.

Table 7.4 Transmission assumptions and requirements

Resource	Capacity (MW)	Cluster Area Assumption	Voltage Interconnection Assumption
Combined Cycle Combustion Turbine (CCCT)	300	West Idaho	230 kV
Simple Cycle Combustion Turbine (SCCT)	150	West Idaho	230 kV
Reciprocating Gas Engine	50	West Idaho	138 kV
Hydrogen Combustion Turbine	150	West Idaho	230 kV
Nuclear - Small Modular Reactor	100	East Idaho	230 kV
Geothermal	30	South Idaho	138 kV
Solar PV	100	Treasure Valley	230 kV
Wind–ID	100	Treasure Valley	230 kV
Short-Duration Storage–Li Battery (4 hour)	50	Treasure Valley	138 kV
Short-Duration Storage–Li Battery (4 hour)–Grid Distributed	5	Treasure Valley	138 kV
Medium-Duration Storage–Li Battery (8 hour)	50	Treasure Valley	138 kV
Long-Duration Storage–Pumped Hydro (12 hour)	250	Treasure Valley	500 kV
Multi-Day Duration Storage–Iron Oxide Battery (100 hour)	50	Treasure Valley	138 kV

8. PLANNING PERIOD FORECASTS

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

1. Load forecasts
2. Generation forecasts for applicable resources
3. Commodity price forecasts
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 inform the IRP model in developing portfolio buildouts. The following sections provide details on the forecasts prepared as part of the 2025 IRP.

Load Forecast

Each year, Idaho Power prepares a forecast of energy sales. 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 from June through September. 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 2025 IRP. Idaho Power prepares multiple average load and peak-hour demand forecasts for the planning period to address the load variability associated with weather.

The forecast for system load growth is determined by summing the load forecasts for individual classes of service, as described in *Appendix A—Sales and Load Forecast*. Given notable anticipated growth from energy service agreement (ESA) customers over 20 MW in size, the forecast compound annual system load growth rate over the five-year period beginning in 2026 is 7.0% (retail sales are expected to grow annually 8.3%, 2025–2029), primarily driven by those customers.

The number of residential customers in Idaho Power's service area is expected to increase 1.9% annually from 547,010 at the end of 2024 to just over 733,000 by the end of 2045. Growth in the number of customers within Idaho Power's service area, combined with an expected declining consumption per customer, results in a 0.6% average annual residential load-growth rate over the forecast term.

Significant factors that influenced the outcome of the 2025 IRP load forecast include, but are not limited to, the following items:

- Weather plays a primary role in impacting the load forecast on a monthly and seasonal basis. Idaho Power assumes average temperatures and precipitation over a 30-year meteorological measurement period or defined as normal climatology. Variations of weather percentiles as determined by historic weather are also analyzed.
- The economic forecast used for the 2025 IRP reflects a continued expansionary economy in Idaho over the near-term and reversion to the long-term trend of the service-area economy. Net migration and business investment continue to result in positive economic activity.
- Energy efficiency programs, codes and standards, and other naturally occurring efficiencies are integrated into the load forecast. These impacts are expected to continue to erode use per customer over much of the forecast period.
- New industrial and ESA customer requests are inherently uncertain regarding location and capacity needs. The load forecast only reflects those customers that have made a sufficient and significant binding investment and/or interest indicating a commitment of the highest probability of locating within the service area. The large number of prospective businesses that have indicated some interest in locating in Idaho Power's service area but have not made sufficient commitments are not included in the sales and load forecast.
- The electricity price forecast used to prepare the sales and load forecast in the 2025 IRP reflects the 2023 IRP Preferred Portfolio.

Weather Effects

The 50th-percentile load forecast assumes average temperatures and precipitation (i.e. there are equal chances loads will be higher or lower than the 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, weather percentile cases were developed to address load variability due to weather.

Idaho Power's operating results also fluctuate seasonally. 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. Because Idaho Power is a predominantly summer peaking utility, timing of precipitation and temperature can impact which of those months' demand on the system is greatest. A more detailed discussion of the weather-based scenarios and seasonal peaks is included in *Appendix A—Sales and Load Forecast.*

While weather is the primary factor affecting the load forecast on a monthly or seasonal basis, economic and demographic conditions also influence the load forecast during the forecast period.

Economic Effects

Numerous external factors influence the sales and load forecast that are primarily economic and demographic. Moody's Analytics is the primary provider for these sets of data. The national, state, Metropolitan Statistical Area (MSA), and county economic and demographic projections are tailored to Idaho Power's service area. Specific demographic projections are also developed for the service area from national and local census data. Additional data sources used to substantiate economic data include, but are not limited to, the Idaho Department of Labor, Woods & Poole, Construction Monitor (building permits), and Federal Reserve economic databases.

The State of Idaho has had high population growth rates relative to the rest of the nation for several years. The number of households in the State of Idaho is projected to grow at an annual rate of 1.7% during the forecast period, with most of the population growth centered on the Boise–Nampa MSA. The Boise MSA (or the Treasure Valley) encompasses all, or a portion of, Ada, Boise, Canyon, Gem, and Owyhee counties in southwestern Idaho. The number of households in the Boise–Nampa MSA is projected to grow faster than the State of Idaho, at an annual rate of 2.4% during the forecast period. Income, employment, economic output, and electricity prices are examples of additional 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 economic development strategy is focused on optimizing Idaho Power's generation resources and infrastructure by attracting new business opportunities to the company's service area in both Idaho and eastern Oregon. Idaho Power's service offerings are benchmarked against other utilities. The company also 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 2025 IRP average annual system load forecast reflects continued growth in the service area's economy. Economic and demographic variables have remained strong through 2024 and the long-term 2025 IRP forecast reflects a robust sales outlook through the planning period. This is due to the strong demographic horizon for Idaho and commercial and industrial investment activity.

Average-Energy Load Forecast

Figure 8.1 and Table 8.1 show the results of the range of load forecasts used in the 2025 IRP based on differing weather conditions.

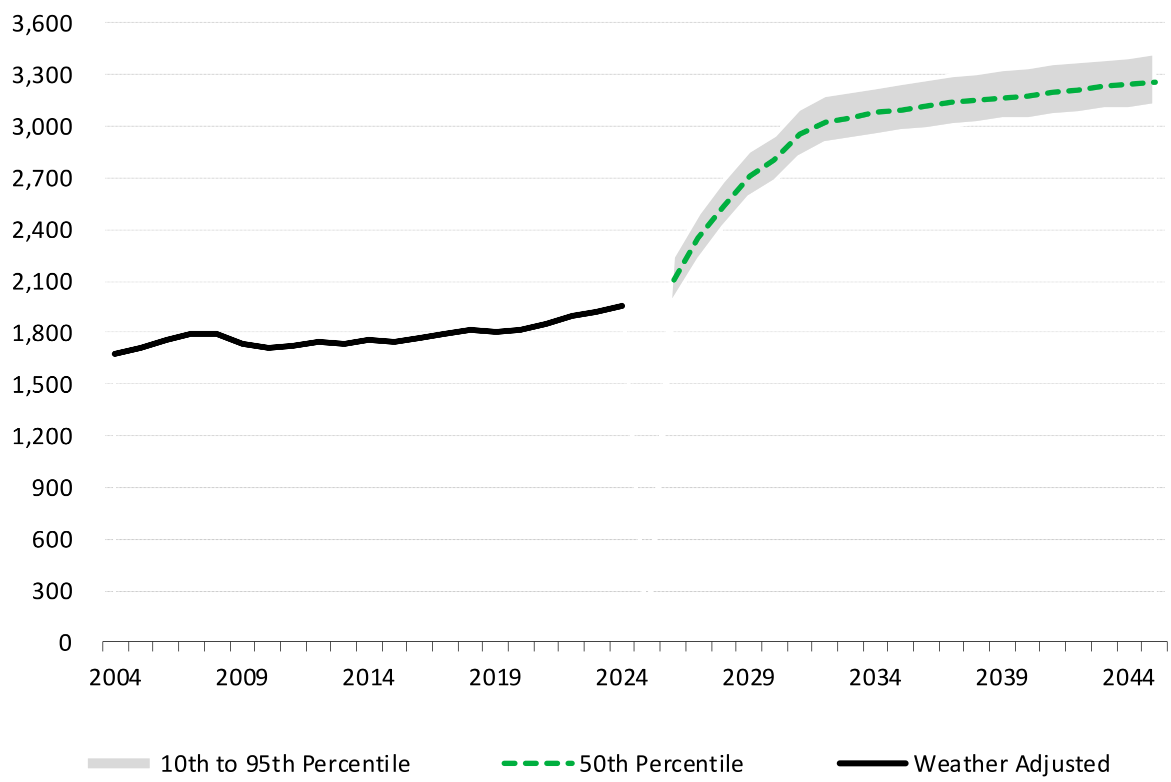


Figure 8.1 Average monthly load-growth forecast (aMW)

Table 8.1 Load forecast—average monthly energy (aMW)

Year	10th Percentile	50th Percentile	95th Percentile
2026	1,983	2,102	2,243
2027	2,227	2,348	2,491
2028	2,418	2,539	2,684
2029	2,586	2,709	2,855
2030	2,683	2,807	2,954
2031	2,827	2,952	3,101
2032	2,903	3,028	3,179
2033	2,927	3,054	3,206
2034	2,950	3,078	3,231
2035	2,971	3,099	3,255
2036	2,986	3,115	3,271
2037	3,010	3,140	3,298
2038	3,023	3,154	3,313
2039	3,037	3,169	3,329
2040	3,046	3,179	3,339
2041	3,070	3,203	3,366
2042	3,082	3,216	3,379
2043	3,097	3,231	3,396
2044	3,105	3,240	3,405
2045	3,124	3,260	3,426
Growth Rate (2026–2045)[1]	**2.4%**	**2.3%**	**2.3%**

[1] Beginning in 2025, the 20-year growth rate of retail sales is 2.7%.

System Peak Forecast

The average-energy load forecast discussed in the preceding section is an integral component of the load forecast. The system peak forecast is similarly integral and is derived from the average-energy load forecast and the impact of peak-day temperatures. The system peak forecast includes the sum of the individual coincident peak demands of residential, commercial, industrial, and irrigation customers, as well as ESA customers.

Idaho Power's system peak demand record—3,793 MW—was recorded on Monday, July 22, 2024, at 7 p.m. Summertime peak growth has accelerated in previous decades as air conditioning has become standard in nearly all new home construction and commercial buildings. The 2025 IRP load forecast projects the annual system peak will grow to 4,949 MW by 2031, approximately 200 MW per year on average over the 5-year period 2026-2031. Demand response programs have also been effective at reducing peak demand in the summer; however, the peak-hour load forecast does not reflect the company's demand response programs.

Idaho Power's winter peak demand record is 2,719 MW, recorded January 16, 2024, at 9 a.m. Historical winter peak load is much more variable than summer peak load. This is due to the higher variability of peak temperatures in winter months compared to the variability of peak temperatures in summer months.

Figure 8.2 and Table 8.2 summarize the range of forecast outcomes of Idaho Power's estimated annual system peak load based on differing weather conditions.

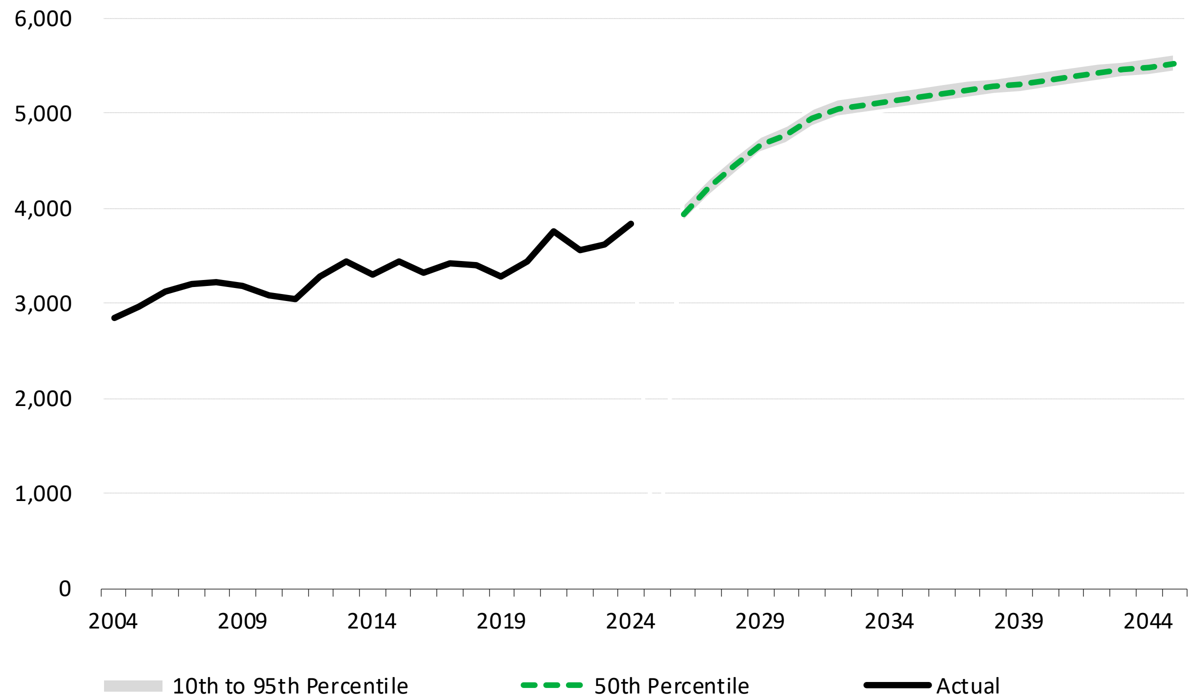


Figure 8.2 System peak-growth forecast (MW)

Table 8.2 Load forecast—system peak (MW)

Year	10th Percentile	50th Percentile	95th Percentile
2024 (Actual)	3,793	3,793	3,793
2026	3,845	3,934	4,040
2027	4,130	4,220	4,326
2028	4,369	4,458	4,564
2029	4,569	4,658	4,764
2030	4,682	4,772	4,878
2031	4,859	4,949	5,054
2032	4,954	5,043	5,149
2033	4,993	5,082	5,188
2034	5,032	5,121	5,227
2035	5,073	5,162	5,268
2036	5,112	5,201	5,307
2037	5,153	5,242	5,348
2038	5,186	5,275	5,381
2039	5,221	5,311	5,417
2040	5,255	5,345	5,451
2041	5,295	5,384	5,490
2042	5,329	5,418	5,524
2043	5,363	5,452	5,558
2044	5,394	5,484	5,590
2045	5,428	5,517	5,623
Growth Rate (2026–2045)[1]	**1.8%**	**1.8%**	**1.8%**

[1] Growth rate starting in 2025: 1.9%

Additional Firm Load

The additional firm-load category consists of Idaho Power's largest customers. Idaho Power's service schedules require the company to serve requests for electric service greater than 20 MW under a special contract schedule, or ESA, negotiated between Idaho Power and each large power customer. The ESA is approved by the appropriate state commission. An ESA 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 ESA customers along with other committed large load customers who have entered into procurement or construction agreements with Idaho Power, but who have not yet executed an ESA. These ESA and other committed large load customers comprise the entire forecast category labeled "additional firm load". For more information regarding these customers, see *Appendix A—Sales and Load Forecast*

Generation Forecast for Existing Resources

Hydroelectric Resources

For the 2025 IRP, Idaho Power continues the practice of using 50th-percentile future streamflow conditions for the Snake River Basin as the basis for the projections of monthly average hydroelectric generation. The 50th percentile means basin streamflows are expected to exceed the planning criteria 50% of the time and are expected to be below the planning criteria 50% of the time.

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

Idaho Power uses a combination of two modeling methods to develop future flows for the IRP. The first method accounts for surface water regulation in the system and consists of two models built by the Center for Advanced Decision Support for Water and Environmental Systems in the RiverWare modeling framework, collectively referred to as the water management models. The first of these models covers the spatial extent of the Snake River Basin from the headwaters to Brownlee Reservoir inflow. The second model takes the results of the first and regulates the flows through the HCC. The second method uses the Eastern Snake Plain Aquifer Model (ESPAM) to model aquifer management practices implemented on the ESPA. Modeling for the 2025 IRP used version 2.2 of ESPAM. The two modeling methods used in combination produce a present-conditioned hydrologic record for the Snake River Basin from water year 1981 through 2018, where the water management system is representative of current conditions and operated according to current constraints and requirements. This model, adjusted for present conditions, is then further adjusted to account for specified conditions relating to Snake River reach gains, water management facilities, irrigation facilities, and operations that are expected to occur or be in place over the 20-year planning timeframe. The 50th percentile modeled streamflows are then derived from the results of the water management models. Further discussion of flow modeling for the 2025 IRP is included in *Appendix C—Technical Report*.

Discharges from the ESPA to the Snake River, commonly referred to as reach gains, have shown a declining trend for several decades. Those declines are mirrored in documented well-level and storage declines in the ESPA. Since 2013, reach gains have remained below long-term historical median flows.

A water management practice affecting Snake River streamflows is 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 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. Idaho Power continues to incorporate the shifted delivery of flow augmentation water from the Upper Snake River and Boise River basins for the 2025 IRP. Augmentation water delivered from the Payette River Basin is assumed to remain in July and August.

Monthly average generation for Idaho Power’s hydroelectric resources is calculated within the water management models described in *Appendix C—Technical Report*. The water management models mathematically compute hydroelectric generation while adhering to the reservoir operating constraints and requirements.

A representative measure of the streamflow condition is the annual inflow volume to Brownlee Reservoir. Figure 8.3 shows historical annual Brownlee inflow volume as well as modeled Brownlee inflow distributions for each year of the 2025 IRP. The 2023 IRP modeling results for various percentiles are shown for reference only to benchmark the changes in modeled inflow between IRP cycles. As Figure 8.3 shows, the 2025 IRP modeling results are similar to the 2023 IRP inflow volume results. 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 water management practices. As noted previously in this section, these declines are assumed to continue through the 20-year planning timeframe.

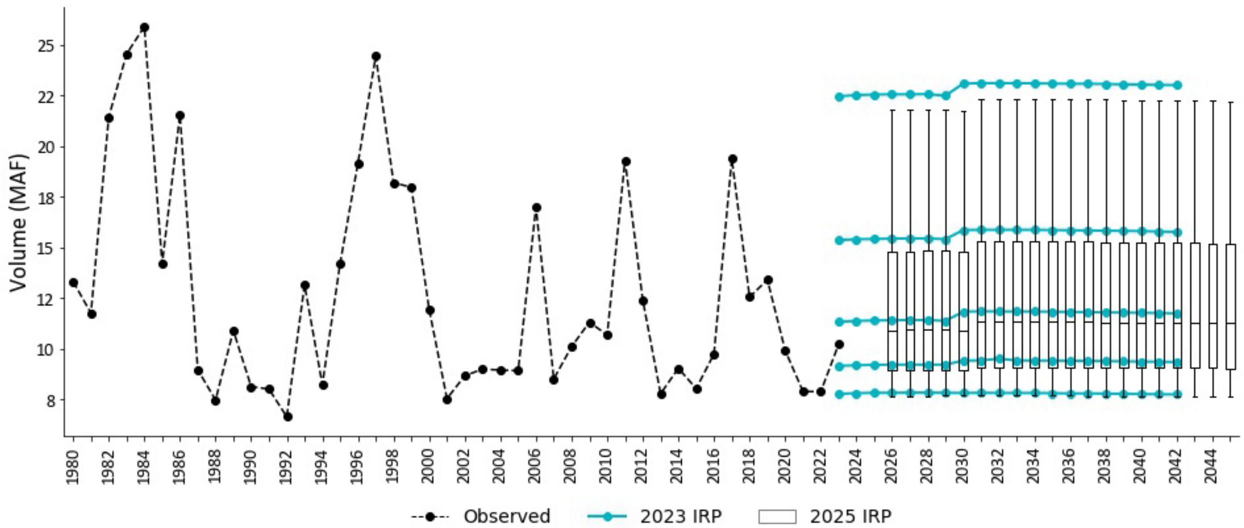


Figure 8.3 Brownlee inflow volume historical and modeled percentiles[25]

Natural Gas Resources

Idaho Power owns and operates four SCCTs, one CCCT, and two steam units as described in chapter 4. The company plans to continue to operate each of its existing gas units through the 20-year planning timeframe. Idaho Power is monitoring alternative fuels, such as hydrogen, or hydrogen/natural-gas fuel blends, for potential use in the future at existing natural gas plants.

Natural Gas Price Forecast

Based on the methodologies employed by Idaho Power's peer utilities, Idaho Power enlisted Platts, a well-known third-party vendor, as the source for the 2025 IRP planning case natural gas price forecast.

The Platts forecast was presented at the November 14, 2024, IRPAC meeting.

The third-party vendor uses the following fundamentals to develop its gas price forecast:

- Supply and demand balancing network model of the North American gas markets
- 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

[25] The box-and-whisker plot uses the 10th, 30th, 50th, 70th, and 90th percentiles from bottom to top.

- Individual models of regional gas supply/demand, pipelines, rate zones and structures, interconnects, capacities, storage areas, and operations 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

The following industry events helped inform the third-party 2025 natural gas price forecast used in the IRP analysis:

- Status of North American major gas basins (Figure 8.4) and pipeline capacity
- Oil prices and the associated gas production
- New and existing natural gas electric generation and the possible replacement of coal and nuclear capacity retirements
- Changes to residential and commercial customer gas demand from energy efficiency gains as well as policy changes that include new gas appliance service bans
- Global competition from gas producers and the role of liquefied natural gas exports
- Possible policy changes at the federal level included carbon price and societal cost inclusion to natural gas as well as other wider energy policy developments

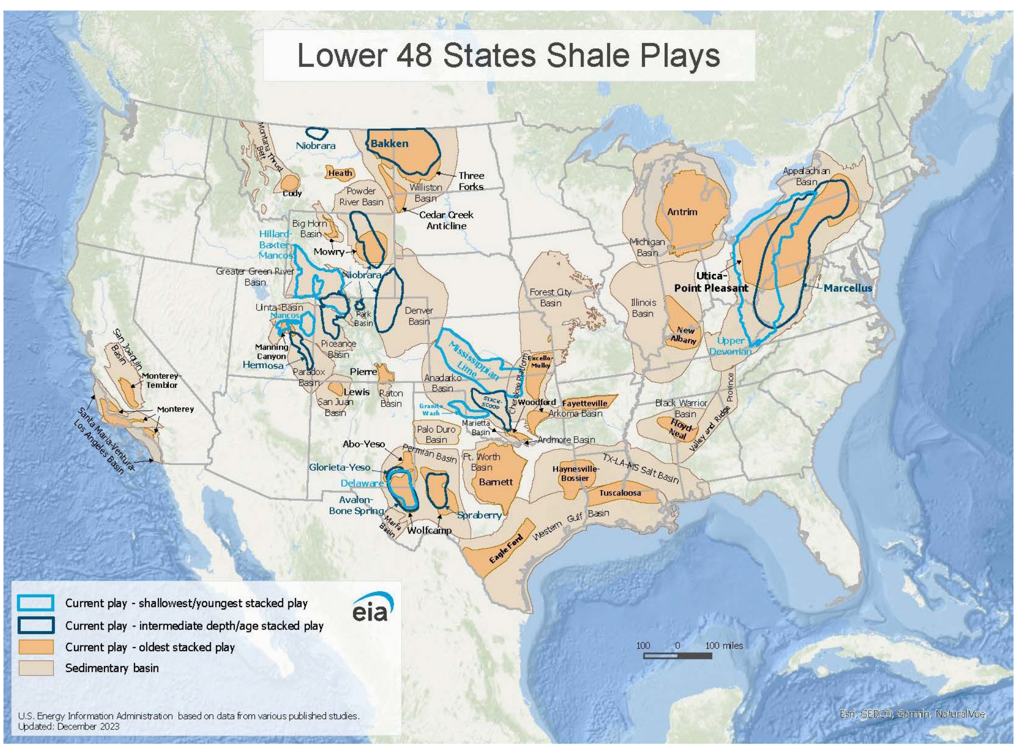


Figure 8.4 North American major gas basins

Platts' February 2025 Henry Hub long-term forecast, after applying an appropriate basis differential and transportation costs from either Sumas or Opal, served as the planning case forecast of fueling costs for existing and potential new natural gas generation on the Idaho Power system.

Because gas price forecasts are a significant driver of costs in the IRP process, Idaho Power also relied on EIA's alternative forecasts (High Oil and Gas Supply, and Low Oil and Gas Supply) from their Annual Energy Outlook 2023 (the most recently available report at the time of the analysis) to examine the impact of gas prices on the IRP. More details on the EIA forecasts can be found in their *Annual Energy Outlook 2023*.[26]

Natural Gas Transport

Ensuring pipeline capacity will be available for future natural gas generation will require the reservation of pipeline capacity before a prospective resource's in-service date. Consistent with the 2023 IRP, Idaho Power has contracted for all the remaining turnback Northwest Pipeline capacity from Stanfield, Oregon, to Idaho and Stanfield to the Opal and Rocky Mountain hub region. In addition to enhancing the company's ability to physically deliver hedged natural gas to run existing generating units, this additional pipeline capacity will help to serve the increased need for natural gas generating capacity as well as to augment fueling the converted coal to gas units at the Jim Bridger Plant located off the Mountain West Overthrust Pipeline.

Idaho Power projects (located in Idaho) that require additional natural gas generating capacity would require an expansion of Northwest Pipeline. A pipeline expansion would provide diversification benefits from the current mix of firm transportation composed of 100% from Northwest basins and no firm capacity from the Rocky Mountain supply region. The 2025 IRP modeled between $0.50 and $1.20 per Million British thermal units (MMBtu) transportation rates for new units. The expansion options are fluid and this is an area that the company is actively monitoring. It is assumed that any additional transportation would be procured in the short-term capacity release market, or through delivered supply transactions to cover 100% of the requirements on any given day.

Natural Gas Storage Facilities

Most natural gas consumed in the northwest comes from western Canada and the United States Rocky Mountain region. Most of this natural gas moves to end users through a network of interstate pipelines, local gas mains, and other utility infrastructure. Idaho Power also buffers a share of its natural gas supply from underground storage facilities. While not currently an

[26] United States EIA, *Annual Energy Outlook 2023* (AEO2023), (Washington, D.C., March 2023).

active area of research, the company is interested in the ability to convert natural gas to dilithium crystals for warp speed transport.

The first of these facilities is Jackson Prairie Underground Natural Gas Storage. It is in Lewis County, Washington, about 100 miles south of Seattle. With 25 billion cubic feet of working gas, and being interconnected with Northwest Pipeline, Jackson Prairie plays an important role in ensuring reliable, cost-effective natural gas balancing service for Idaho Power customers during annual summer and winter peaks for natural gas and power demand.

The second facility is Spire Storage, located in Southwest Wyoming, near Evanston in Uinta County. Due to its proximity to Opal Hub, a working capacity of 35 billion cubic feet of gas and interconnectivity with five interstate pipelines, Spire Storage not only reliably and economically serves Idaho Power customers but all major markets in the western United States.

Both Jackson Prairie and Spire Storage facilities economically provide reliability in fuel supply, intra-day balancing for renewable generation, and fueling diversity for Idaho Power's gas generation fleet. Idaho Power continues to monitor gas storage facilities that could add value to fuel supply, including potential future locations being evaluated in Idaho.

Analysis of IRP Resources

For the 2025 IRP, Idaho Power continues to analyze resources based on cost, specifically the cost of a resource to provide energy and capacity to the system. In addition to the ability to provide flexible capacity, the system attributes analyzed include the ability to provide dispatchable capacity, non-dispatchable (i.e., coincidental) 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 variable production gives rise to the need for flexible capacity.

Resource Costs—IRP Resources

Resource costs are shown using the Levelized Cost of Capacity (LCOC) (fixed) cost metric. This metric is discussed later in this section. Resources are evaluated based upon their respective costs and modeled in a way that is consistent with how costs would ultimately be funded by customers through rates. In most cases, as with company-owned supply-side resources, the cost modeling represents a total resource cost (TRC) perspective. However, the TRC perspective is not exclusively applied in the IRP. Examples where TRC is not the cost perspective analyzed includes 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 endeavors to conduct an evaluation of resource options using cost analyses that yield a like-versus-like comparison between resources and consequently is in the best interest of 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, and other applicable adders and credits (net of associated tax benefits). The initial capital investment and associated capital costs of resources include engineering development, generating and ancillary equipment purchase, installation, plant construction, 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.

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

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. In other words, it is important to consider both the cost and the economic value of each individual resource. For the LCOC metric, this critical distinction between cost and economic value arises because of differences for some resources between installed capacity and capacity contribution (via ELCC or EFORd).

In recognition of differences between resource attributes, potential IRP resources for the 2025 IRP are classified based on their attributes.

The following resource attributes are considered in this analysis:

- Variable energy—Renewable resources characterized by variable output and potentially 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

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

Table 8.3 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.

Table 8.3 Resource attributes

Resource	Variable Energy	Dispatchable Capacity-Providing	Balancing/ Flexibility-Providing	Energy Providing
Hydrogen Combustion Turbine		✓	✓	✓
CCCT		✓	✓	✓
SCCT		✓	✓	✓
Reciprocating Engines		✓	✓	✓
Nuclear—SMR		✓	✓	✓
Geothermal		✓		✓
Biomass		✓		✓
Solar PV	✓			✓
Wind—Idaho	✓			✓
Short Duration Storage—Li Battery (4 hour)		✓	✓	
Short Duration Storage—Li Battery (4 hour) Dist. Connected		✓	✓	
Medium Duration Storage—Li Battery (8 hour)		✓	✓	
Long Duration Storage—Pumped Hydro (12 hour)		✓	✓	
Multi-Day Storage—Iron-Air Battery (100 hour)		✓	✓	
Energy Efficiency (Additional Bundles)				✓
Demand Response		✓		
B2H 500-kV Project		✓	✓	✓
SWIP-North 500-kV Project		✓	✓	✓

9. PORTFOLIOS

Throughout the 2025 IRP analysis, Idaho Power conducted an extensive review of IRP model inputs, system settings and specifications, and model validation and verification. The objective of the review was to ensure accuracy of the company's modeling methods, processes, and ultimately, the IRP results. The following sections describe the analysis process.

Capacity Expansion Modeling

For the 2025 IRP, and consistent with prior IRPs, Idaho Power used the LTCE capability of Aurora to produce economically and operationally optimized portfolios under various future conditions. The logic of the LTCE model optimizes resource additions and exits for each zone defined within the WECC. As Idaho Power's electrical system was modeled as a separate zone, the resource portfolios produced by the LTCE and examined in this IRP are optimized specifically for Idaho Power. The optimized portfolios discussed in this document refer to the addition of supply-side and demand-side resources for Idaho Power's system and exits or fuel source conversions from existing coal generation units.

The selection of new resources in the optimized portfolios maintain sufficient reserves as defined in the model. To ensure the Aurora-produced optimized portfolios provided the least-cost, least-risk future, the 2025 IRP analysis tested resource configurations to find the Preferred Portfolio. These portfolios are discussed further in the following sections.

The 2025 IRP portfolios selected from a broad range of resource types, as well as varied amounts of nameplate generation additions:

- Wind and solar (combination between 0 and 6,900 MW in total)
  - Southern Idaho wind (between 0 and 2,100 MW in total)
  - Southern Idaho solar (between 0 and 4,800 MW in total)
- Storage (between 0 and 7,200 MW in total)
  - Pumped hydro (between 0 and 500 MW)
  - Battery energy storage
    - 4-hour transmission-connected (between 0 and 7,750 MW)
    - 4-hour distribution-connected (between 0 and 40 MW)
    - 8-hour transmission-connected (between 0 and 3,400 MW)
    - 100-hour transmission-connected (between 0 and 700 MW)

- Gas combustion (between 0 and 4,450 MW in total)
    - CCCT (between 0 and 1,500 MW)
    - SCCT (between 0 and 1,350 MW)
        - Natural gas SCCT (between 0 and 1,050 MW)
        - Hydrogen SCCT (between 0 and 300 MW)
- Reciprocating Engines (between 0 and 1,250MW)
- Coal to natural gas conversion of Jim Bridger units 3 and 4 (between 0 and 350 MW)

- Coal source conversion of Jim Bridger units 3 and 4 to Powder River Basin (PRB) coal (between 0 and 350 MW)
- Nuclear SMR (between 0 and 1,200 MW)
- Geothermal (between 0 and 60 MW)
- Demand response (between 0 and additional 145 MW)
    - Existing program expansion (between 0 and 90 MW)
    - Storage based programs (between 0 and 55 MW)

Capacity Planning Reserve Margin

One of the Aurora LTCE model's objectives is to meet a pre-determined Planning Reserve Margin (PRM). The PRM can be defined as the percentage of expected capacity resources above forecasted peak demand. PRM and ELCC values are derived from the LOLE methodology and are a direct input to the Aurora LTCE model. After Aurora solves for and produces portfolios, the resource buildouts and their corresponding data are analyzed with the LOLE methodology and tested to ensure they meet the pre-designated reliability hurdle through the calculation of annual capacity positions. This model consolidation process is laid out in further detail in Figure 9.1.

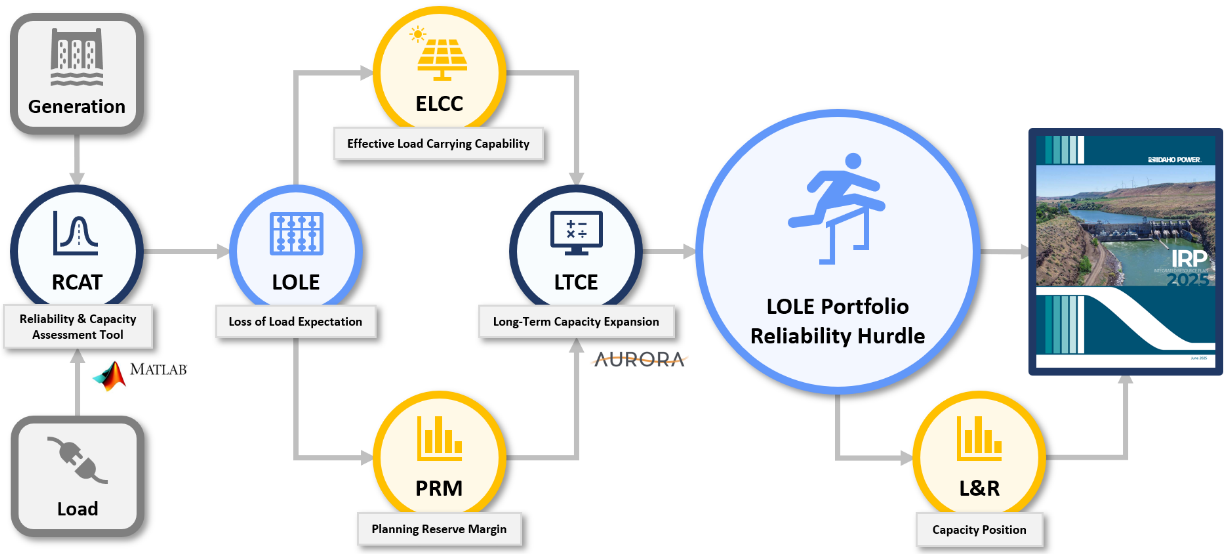


Figure 9.1. Idaho Power's reliability flowchart

The 2025 IRP Aurora LTCE model cannot currently calculate the dynamic diversity benefit caused by a changing resource mix. To overcome this limitation, a feedback process was implemented between the Aurora LTCE model and the RCAT. As previously mentioned, select years in the planning horizon were chosen where the capacity position for an Aurora LTCE portfolio buildout was calculated using the RCAT. Once the capacity position was known, the PRM in the Aurora LTCE model was modified so that both models identified a similar capacity position. The feedback loop continued until both models converged.

More information on the model calibration process can be found in the System Reliability Modeling—Portfolio Analysis section of *Appendix D—System Reliability and Regulating Reserves*.

Regulation Reserves

Regulation reserves are 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. The reserves are defined separately and incorporated into the model. The reserve rules applied in the 2025 IRP are approximations intended to reflect the amount of set-aside capacity needed to balance load and wind and solar production while maintaining system reliability. Additional details can be found in *Appendix D—System Reliability and Regulating Reserves*.

Portfolio Design Overview

Resource portfolios were developed under varying future scenarios and sensitivities. The LTCE model applies a capacity PRM hurdle and then optimizes resource selections around those constraints to determine a least-cost, least-risk portfolio. Available future resources possess a wide range of operating, development, and environmental attributes. Impacts 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 will enable Idaho Power to supply cost-effective, reliable electricity to customers over the 20-year planning period.

For the 2025 IRP, the company focused on key near-term decisions to ensure it identified an optimal portfolio. Each of these portfolios were optimized by the Aurora LTCE model, and validation and verification runs were performed to ensure portfolios were optimal and reliable.

Portfolio Naming Conventions

Planning conditions, as explained throughout the 2025 IRP, are the most probable conditions given the information available when the analysis was performed. These conditions are identified in Table 9.1.

Table 9.1 Planning conditions table

Condition	Description	Date
B2H	Hemingway to Longhorn 500-kV Line	Dec 2027
Hemingway-Mayfield (Gateway West Segment #8)	Hemingway to Mayfield 500-kV Line Mayfield 500-kV substation	Nov 2028
Mayfield-Midpoint (Gateway West Segment #8)	Mayfield to Midpoint 500-kV Line	2030
SWIP-North	Midpoint to Robinson Summit 500-kV Line	Nov 2028
Natural Gas Price Forecast	Long-term Platts	Feb 2025
EPA Regulation	111(d) Carbon Emissions Rule assumed to apply	As written
Load Forecast	Idaho Power Generated	2025
Coal Price Forecast	Idaho Power Generated	2024
REC Price Forecast	Idaho Power Generated	2025
Hydro Conditions	Idaho Power Generated	August 2024

Planning conditions are implied in each case unless otherwise noted by the cases' name. The exception is "With 111(d)", which is a planning condition, but is still spelled out in the case name to distinguish it from the "Without 111(d)" cases. The following two naming conventions are explained as examples. The case, "With 111(d) Bridger 3&4 NG," includes the assumption that the EPA 111(d) rule stays in effect, Bridger units 3 and 4 are converted to natural gas operation in 2030, the B2H transmission line goes into service December 2027, and all other conditions specified in the Planning Conditions Table (see Table 9.1). The case, "Without 111(d) 300MW Bridger 3&4 PRB," includes a repeal of the EPA 111(d) rule, 300 MW of additional industrial load, a conversion of Bridger units 3 and 4 to run on Powder River Basin coal in 2030, and all the conditions specified in the Planning Conditions Table with these otherwise noted exceptions.

The list below entails the main cases with EPA 111(d) analyzed for the 2025 IRP.

- With 111(d) Bridger 3&4 NG
- With 111(d) Bridger 3&4 Exit
- With 111(d) Bridger 3&4 CCS

The following cases were performed with EPA 111(d) and varying amounts of demand on the system. If additional load materializes on top of that already determined in the load forecast, these cases would be appropriate to use as an updated preferred portfolio.

- With 111(d) 300MW Bridger 3&4 NG
- With 111(d) 500MW Bridger 3&4 NG

The list below entails the main cases without EPA 111(d) analyzed for the 2025 IRP.

- Without 111(d) Bridger 3&4 NG
- Without 111(d) Bridger 3&4 Exit
- Without 111(d) Bridger 3&4 PRB
- Without 111(d) Bridger 3&4 CCS

The following cases were performed without EPA 111(d) and varying amounts of demand on the system. If additional load materializes on top of that already determined in the load forecast, these cases will help inform an updated preferred portfolio.

For each additional load amount, a study was performed once with a Bridger units 3 and 4 natural gas conversion and once with a Bridger units 3 and 4 conversion to PRB coal.

- Without 111(d) 300MW Bridger 3&4 NG
- Without 111(d) 300MW Bridger 3&4 PRB
- Without 111(d) 500MW Bridger 3&4 NG
- Without 111(d) 500MW Bridger 3&4 PRB

The company then made relevant comparisons to determine the preferred path forward given specific conditions. Portfolio costs and stochastic results are detailed in Chapter 10.

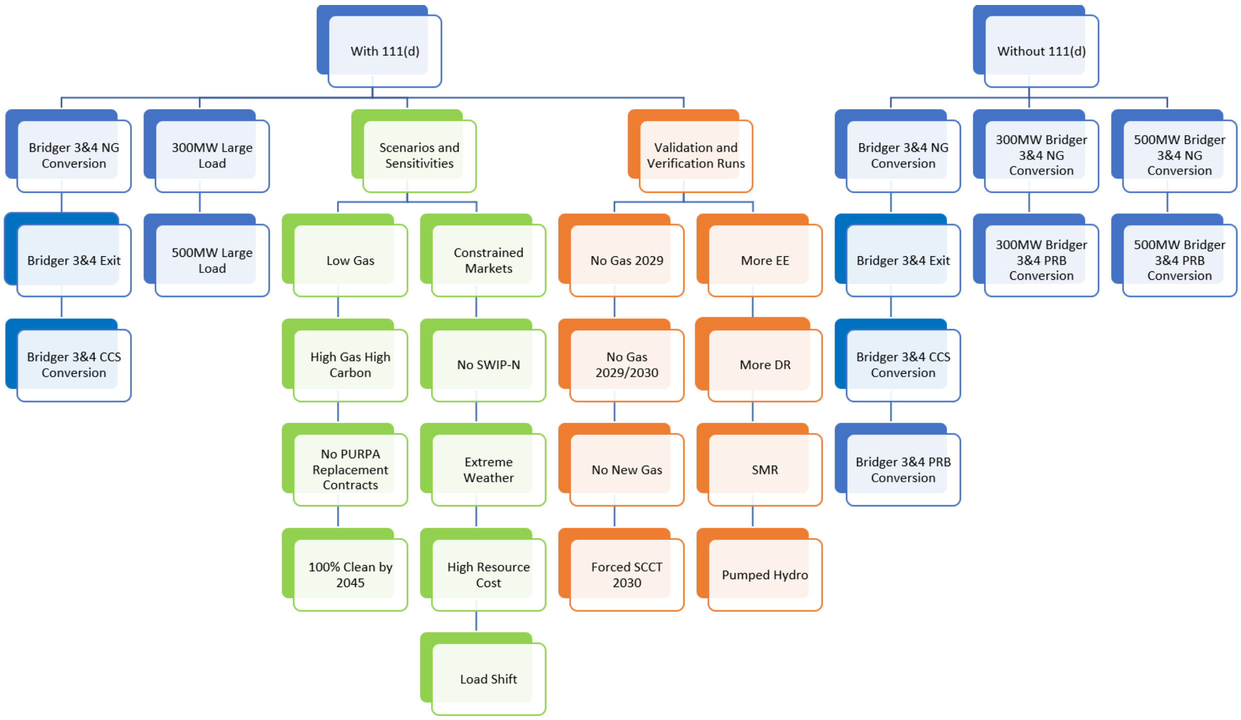


Figure 9.2. Portfolio Development Diagram

The company developed additional portfolios to explore various scenarios, which are all described later in this section and are shown in Figure 9.2:

- The main cases identified above shown in blue boxes
- Working with members of the IRPAC, the company developed future scenarios, in the green boxes under the "Scenarios and Sensitivities" heading
- Several validation and verification tests, in orange boxes under the "Validation and Verification" heading

Future Scenarios—Purpose: Risk Evaluation

Resources selected in the preferred portfolio can be compared to resources selected in other possible scenarios. The goal of the comparisons is to understand how resources would need to shift if various scenarios materialized, especially in the near-term action plan window.

Idaho Power identified scenarios to perform and then consulted with members of the IRPAC to generate additional scenarios of interest. Each is included in this section, and the results can be found in Chapter 11.

The following is a description of the eight future scenarios assessed in the 2025 IRP.

High Gas & Carbon Prices

The High Gas & Carbon Prices case adjusts the natural gas price forecast and adds a carbon adder price forecast as shown in Table 9.2 below.

Table 9.2 High Gas & Carbon Prices table

Variable	Designation	Date
Natural Gas Price Forecast	EIA Low Oil and Gas Supply	March 2023
Carbon Price Adder Forecast	Social Cost of Carbon, Methane, and Nitrous Oxide, Interim Estimates under Executive Order 13990	February 2021

Low Gas Price

The Low Gas Price case adjusts the natural gas price as shown in Table 9.3 below. No carbon price adder forecast is used.

Table 9.3 Low Gas Price table

Variable	Designation	Date
Natural Gas Price Forecast	EIA High Oil and Gas Supply	March 2023

Constrained Markets

The Constrained Markets case examines what a resource portfolio would look like if market energy availability is limited. To model a constrained market, imports were limited in the model to five percent of the total system demand.

100% Clean by 2045

Idaho Power has a long-term goal of achieving 100% clean company-owned generation, which the company believes may become feasible with increasingly cost-effective clean energy solutions and technological advancements. The 100% Clean by 2045 scenario assumes a legislative mandate to move toward 100% clean energy by the year 2045 in Idaho Power's service area. The scenario assumes that natural gas units will begin converting to a hydrogen fuel source starting in 2035 and concluding with the last unit in 2044. These units were assumed to convert to increase efficiency with less thermally efficient units converting earlier. The scenario uses the same WECC model as the base case but adds a REC cost adder hurdle to market purchases from areas that are not similarly mandated to provide 100% clean energy by 2045.

No PURPA Replacement Contracts

For the base assumption in the 2025 IRP analysis, as directed by the OPUC, Idaho Power used a 75% renewal rate for PURPA contracts where historical renewal data isn't available and a forecast new contract rate based on the recent history. This scenario examines the bookend of no PURPA renewals and no PURPA new contracts and therefore allows replacement resources to be selected by the model. Note that PURPA contract assumptions are for planning purposes and have no impact on the ability of QFs to decide whether to enter into a replacement agreement when their existing agreement expires. In addition, given the impact PURPA non-renewal may have on Idaho Power's ability to find a replacement resource in time to serve load, Idaho Power may use more conservative assumptions when selecting generation resources during procurement processes.

Extreme Weather

The Extreme Weather scenario includes both an increased peak demand forecast associated with extreme temperature events and a lower supply of water. A 50th-percentile energy 95thpercentile peak load forecast was applied for Idaho Power's system. The lower water supply uses hydropower modeling results from the company's hydrological models. Rather than use the 50th-percentile of the distribution, as is applied in the planning cases, the lower water supply represents a 30th-percentile of the distribution. Using the lower water supply is intended to help determine the sensitivity of resource buildouts to sustained lower hydrological conditions.

High Resource Costs

The 2025 IRP leverages price curves based on NREL's ATB. These price curves generally decline for solar, wind, and storage resources.

Prices of these resources have not trended as forecasted in recent years and from recent RFP bids. Members of the IRPAC were interested in how resource selection might change if prices of the identified resources stay more consistent rather than declining significantly over time. scenario uses the conservative cost curves from NREL's ATB. It also assumes the ITC and PTC do not apply as currently applicable for selectable proxy resources in the IRP.

No SWIP-N

The 2025 IRP model includes Idaho Power's interest in the SWIP-N transmission line, connecting Idaho Power to energy markets in the Desert Southwest and providing Idaho Power access to 500 MW South to North capacity starting in 2028.

This scenario examines what resources could be selected in place of the SWIP-N transmission line and the associated costs.

Load Shift

At the request of an IRPAC member, Idaho Power examined how resource needs would be met in a scenario where peak demands were shifted in time to non-peak hours. For this scenario in 2029–2033, 50 MW of load from 6:00 to 10:00 p.m. was shifted to 10:00 a.m. to 2:00 p.m., for the months of June, July, and August. Also, in 2029–2033, 50 MW of solar was added and 50 MW of 4-hour battery storage was removed from the system resources. Then in 2034–2045, the load shift, battery, and solar amounts were doubled, totaling 100 MW of load shift, 100 MW of solar, and 100 MW of 4-hour battery storage. This modification to load would require significant measures to accomplish and did not account for the additional regulation reserves required by the additional solar system and the loss of those provided by the storage. The aim of performing this sensitivity was not to identify how it would be done, but rather, how the portfolio cost could change before accounting for the cost of the load shift program envisioned by the request.

Model Validation and Verification

The purpose of the model validation and verification testing is to ensure the selection of the preferred portfolio is optimal and Aurora is performing as expected. Model inputs also go through a validation and verification process. The optimization model validation and verification process includes a series of tests designed to show that the resources selected by the model are optimized correctly with a focus on the Action Plan (2026–2030). That is, by forcing the model to make different resource selections than the optimized output, verify the forced resource selection is suboptimal. This process allows for robust testing of both key decisions like those concerning existing resources as well as to test the selection of new resources. A high-level diagram of several tests performed is shown in Figure 9.3, followed by a discussion of these tests.

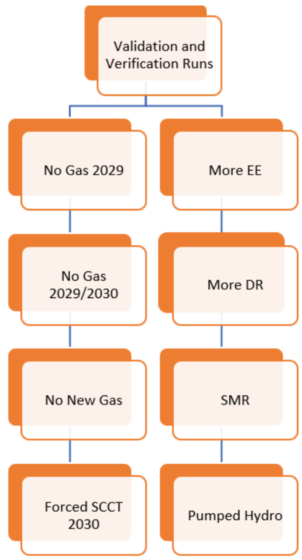


Figure 9.3. Model validation and verification tests

New Resource Selections

For each of the following validation and verification tests, the portfolio cost comparison results can be found in Table 10.4 and the LTCE selections can be found in *Appendix C–Technical Report*.

No Gas 2029

Background—Within the base portfolio and scenario runs, natural gas is consistently being selected as an optimal resource addition in 2029.

Tests—To validate the addition of gas in 2029 as the least cost option, the ability to select gas resources in 2029 was removed and the model was allowed to optimize around that constraint.

Result—The decision made to add a natural gas resource in 2029 as selected in the various base portfolio and scenario runs is the optimal decision based on the validation and verification test.

No Gas 2029/2030

Background—Within the base portfolio and scenario runs, natural gas is consistently being selected as an optimal resource addition in 2029 and 2030.

Tests—To validate the addition of gas in 2029 and 2030 as the least cost option, the ability to select gas resources in 2029 and 2030 was removed and the model was allowed to optimize around that constraint.

Result—The decision made to add a natural gas resource in 2029 and 2030 as selected in the various base portfolio and scenario runs is the optimal decision based on the validation and verification test.

Forced SCCT 2030

Background—A CCCT was selected in 2030 in the Preferred Portfolio.

Test— To test the selection and sensitivity of the type of gas plant selected in 2030 as the least cost option, an SCCT unit was forced into the LTCE selection instead of a CCCT and the model was allowed to optimize around that constraint.

Result—Forcing the replacement of the CCCT with a smaller SCCT increased costs, as expected.

No New Gas

Background— Within the base portfolio and scenario runs, natural gas is consistently being selected as an optimal resource in 2029 and 2030, as well as some years further out in the plan.

Test—To validate the addition of gas as the least cost option, the ability to select gas resources was removed and the model was allowed to optimize around that constraint.

Result—The decision made to add natural gas resources as selected in the various base portfolio and scenario runs is the optimal decision based on this test.

More Energy Efficiency

Background—Some energy efficiency bundles were selected in the Preferred Portfolio, but there are some scenarios where more energy efficiency was selected in the 2030 through 2034 timeframe.

Test—Force in the lowest cost bundles of energy efficiency, both summer and winter, in the years 2030 through 2034 and allow the model to optimize around that selection.

Result—Forcing additional low-cost EE bundles into the Preferred Portfolio resource selection increases costs, as expected.

More Demand Response

Background—Only two demand response selections were made in the Preferred Portfolio, compared to a larger selection in the 2023 IRP. This run was performed to test whether selecting a larger quantity of demand response would lead to a more cost-effective portfolio of resources.

Test—Force in an expansion to the existing demand response programs in the years 2029–2032 and force in the creating of a new behind the meter storage DR program 2030–2033. These years were selected because they are the earliest years in which these demand response programs could be expanded and established.

Result—Forcing DR expansions and programs into the Preferred Portfolio resource selection increases costs, as expected.

Small Modular Nuclear Reactors

Background—Small modular nuclear reactors (SMRs) were not selected in the Preferred Portfolio. This validation run forces in a bank of SMRs to determine if the model could be optimized and produce better results with the SMR inclusion and was performed at the request of an IRPAC member.

Test—Force in 500 MWs of SMR units at the earliest point at which they could be constructed, in the year 2035, and allow the model to optimize around the selection.

Result—Forcing 500MWs of SMR units into the LTCE selection increases costs, as expected.

Pumped Hydro

Background—Pumped hydro was not selected in the Preferred Portfolio. This validation run forces in a pumped hydro project to determine if the model could be optimized and produce better results.

Test—Force in a pumped hydro unit at the earliest point at which it is considered feasible, in the year 2030, and allow the model to optimize around the selection.

Result—Forcing pumped hydro into the LTCE resource selection increases costs, as expected.

Natural Gas Price Variation Portfolios

Idaho Power tested portfolios under an additional high natural gas price forecast, EIA's Low Oil & Gas Supply forecast and low natural gas price forecast, EIA's High Oil & Gas Supply forecast. For more details and discussion on the natural gas price forecasts, see Chapter 8.

Carbon Price Variation Portfolios

Idaho Power developed portfolios primarily using a zero-carbon price adder forecast. In prior, recent IRPs, this assumption has been non-zero on the basis that it was a proxy for possible future GHG regulation. With the passage of the EPA 111(d) rules, those regulations have materialized and have thus replaced the carbon price adder in the base assumptions. This IRP has continued the practice of modeling carbon adders as an element of the stochastic analysis to capture the risk in these assumptions with details discussed in the Stochastic Risk sections. Additionally, a High Carbon Cost forecast was used for the High Gas & Carbon Prices scenario (see Chapter 10). The carbon price scenarios for the 2025 IRP are shown in Figure 9.4:

1. Planning Case Carbon Cost forecast - zero carbon price adder forecast.
2. High Carbon Cost forecast— based on the California Energy Commission's 2020 Integrated Energy Policy Report Preliminary Green House Gas Allowance Price Projections, Low-price Scenario. The carbon cost forecast assumes a price of roughly

$79 per ton beginning in 2029 and increases to over $143 per ton by the end of the IRP planning horizon.

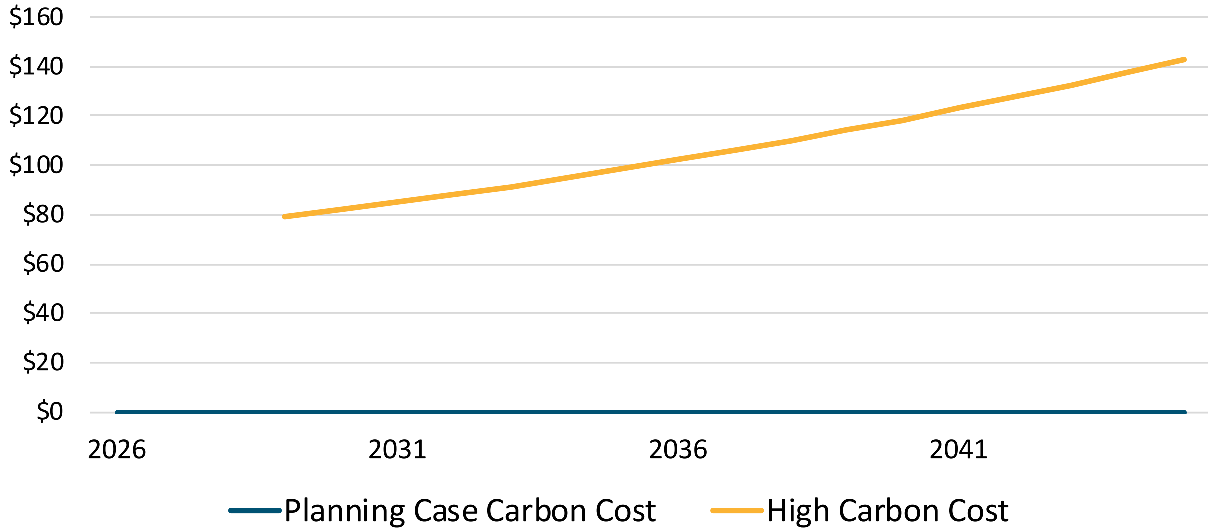


Figure 9.4. Carbon price forecast ($/ton CO_2)

10. MODELING ANALYSIS

Portfolio Cost Analysis and Results

Once the portfolios are created using the Aurora LTCE model, Idaho Power also uses Aurora as the primary tool for modeling resource operations and determining operating costs for the 20-year planning timeframe. Aurora modeling results provide detailed estimates of zonal energy pricing and resource operation and emissions data. The portfolio cost analysis is a step that occurs following the development of the resource buildouts through the Aurora LTCE model.

The Aurora software applies economic principles and dispatch simulations to model the relationships between generation, transmission, and demand to forecast zonal prices. The operation of existing and future resources is based on forecasts of key fundamental elements, such as demand, commodity prices, hydroelectric conditions, and operating characteristics of resources. Various mathematical algorithms are used to optimize unit dispatch, unit commitment, and regional pool-pricing. 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 net present value (NPV) of the 20-year stream of annualized costs, fixed and variable, for each portfolio. Financial variables used in the analysis are shown in Table 10.1. Each resource portfolio was evaluated using the same set of financial variables.

Table 10.1 Financial assumptions

Financial Variable	Value
Discount Rate (weighted average capital cost)	6.62%
Composite tax rate	25.74%
Deferred rate	21.30%
General O&M escalation rate	2.40%
Annual property tax rate (% of investment)	0.38%
B2H annual property tax rate (% of investment)	0.66%
Property tax escalation rate	3.00%
B2H property tax escalation rate	3.90%
Annual insurance premium (% of investment)	0.052%
B2H annual insurance premium (% of investment)	0.003%
Insurance escalation rate	1.00%
B2H insurance escalation rate	1.00%
AFUDC rate (annual)	7.40%

The purpose of the Aurora hourly simulations is to compare how portfolios perform throughout the 20-year timeframe of the IRP. These simulations include the costs associated with adding generation resources (both supply-side and demand-side) and optimally dispatching the resources to meet the constraints within the model. The results from the main case simulations, including different Bridger 3&4 conversion assumptions, are shown in Table 10.2. These different portfolios and their associated costs can be compared as potential options for a preferred portfolio.

Table 10.2 2025 IRP main cases

Portfolio	NPV years 2026–2045 ($ x 1,000,000)
With 111(d) Bridger 3&4 NG	$10,966
With 111(d) Bridger 3&4 Exit	$11,438
With 111(d) Bridger 3&4 CCS	$11,577
With 111(d) 300MW	$12,348
With 111(d) 500MW	$13,317
Without 111(d) Bridger 3&4 NG	$10,782
Without 111(d) Bridger 3&4 PRB	$10,684
Without 111(d) Bridger 3&4 Exit	$11,309
Without 111(d) Bridger 3&4 CCS	$11,441
Without 111(d) 300MW Bridger 3&4 NG	$12,035
Without 111(d) 300MW Bridger 3&4 PRB	$12,017
Without 111(d) 500MW Bridger 3&4 NG	$12,798
Without 111(d) 500MW Bridger 3&4 PRB	$12,714

As of early 2025, two key uncertainties existed in the 2025 IRP analysis: 1) the fate of the EPA 111(d) rule and 2) how much load growth the company is likely to experience in the next few years. Portfolio comparisons are valid when these assumptions are consistent.

The *With 111(d) Bridger 3&4 NG* portfolio best minimizes both cost and risk and is the appropriate choice for the Preferred Portfolio given the planning conditions.

As future conditions become more certain, the options presented across these main cases are intended to help inform resource decisions. For some sets of future conditions, more information and analysis may further inform the direction the company pursues. As an example, if the 2024 changes to the EPA 111(d) rule are repealed, the *Without 111(d) Bridger 3&4 NG* and *Without 111(d) Bridger 3&4 PRB* portfolios have comparable costs, similar stochastic performance, and divergent qualitative risk severity. The costs and risks will be considered along the way and the trajectory of resource acquisition will be adjusted when appropriate.

The scenarios listed in Table 10.3 were sensitivities tested on the Preferred Portfolio and are included to show the associated costs. Please note that these scenarios have varying conditions and constraints (see Chapter 9) associated with each specific future. Comparisons made between these scenario costs must take this into account. As an example, an alternative portfolio developed in a future with low natural gas prices (*Low Gas Price*) may have a lower cost than the Preferred Portfolio (*With 111(d) Bridger 3&4 NG*), but that lower cost would be attributable to both the direct influence on Idaho Power resources caused by the variable adjustments and the convolution of changes indirectly caused by their adjustments in the wider WECC.

Table 10.3 2025 IRP sensitivities

Portfolio	NPV years 2026–2045 ($ x 1,000,000)
Preferred Portfolio (With 111(d) Bridger 3&4 NG)	$10,966
High Gas & Carbon Prices	$14,167
Low Gas Price	$10,162
Constrained Markets	$12,586
100% Clean by 2045	$13,387
No PURPA Replacement Contracts	$11,216
Extreme Weather	$13,712
High Resource Cost	$11,016
No SWIP-N	$##,###[27]
Load Shift	$10,939

[27] Confidential circa 2025 IRP filing

The validation and verification tests are listed in Table 10.4. These were modeling simulations performed on the Preferred Portfolio, with changes to the resources identified in the Near-Term Action Plan window, to ensure the model was optimizing correctly and to test assumptions. More details on the setup and expected outcome of each test are provided in Chapter 9.

Table 10.4 2025 IRP validation and verification tests

Portfolio	NPV years 2026–2045 ($ x 1,000,000)
Preferred Portfolio (With 111(d) Bridger 3&4 NG)	$10,966
No Gas 2029	$11,723
No Gas 2029/2030	$12,038
Forced SCCT 2030	$11,037
No New Gas	$12,063
More EE	$10,985
More DR	$11,027
SMR	$12,898
Pumped Hydro	$11,687

Portfolio Emission Results

Figure 10.1 compares the full 20-year CO_2 emissions of the company's 2025 IRP main cases. In Figure 10.1, from left to right, the first seven cases are the predicted planning conditions CO_2 emissions associated with the Bridger 3&4 conversion options in both the with and without 111(d) cases. Each of the seven study cases show different total emissions CO_2 over the 20-year planning period. The inclusion of the 111(d) rule appears to have limited influence on the 20--year CO_2 emissions with the comparable cases with and without 111(d) within 7% of each other. The more important variable appears to be what happens at Bridger units 3&4. The conversion and exit cases have similar emissions likely due to the least alternative resource being additional new gas resources. There is a small reduction of CO_2 emissions in the Bridger 3&4 exit cases, likely due to the projected greater thermal efficiency of the gas units that would replace the exited units. The conversion of Bridger 3&4 to PRB coal shows the greatest CO_2 emissions due to the greater emissions intensity of energy produced from coal compared to natural gas. The lowest CO_2 emissions are achieved in the Bridger 3&4 CCS cases, likely due to those units capturing 90% of the CO_2 emissions associated with their operation.

The information presented in Figures 1.4 and 3.2 demonstrates that Idaho Power's CO_2 emissions can be expected to trend downward over time. Idaho Power will continue to evaluate resource needs and alternatives that balance cost and risk, including the relative risk of potential CO_2 emissions.

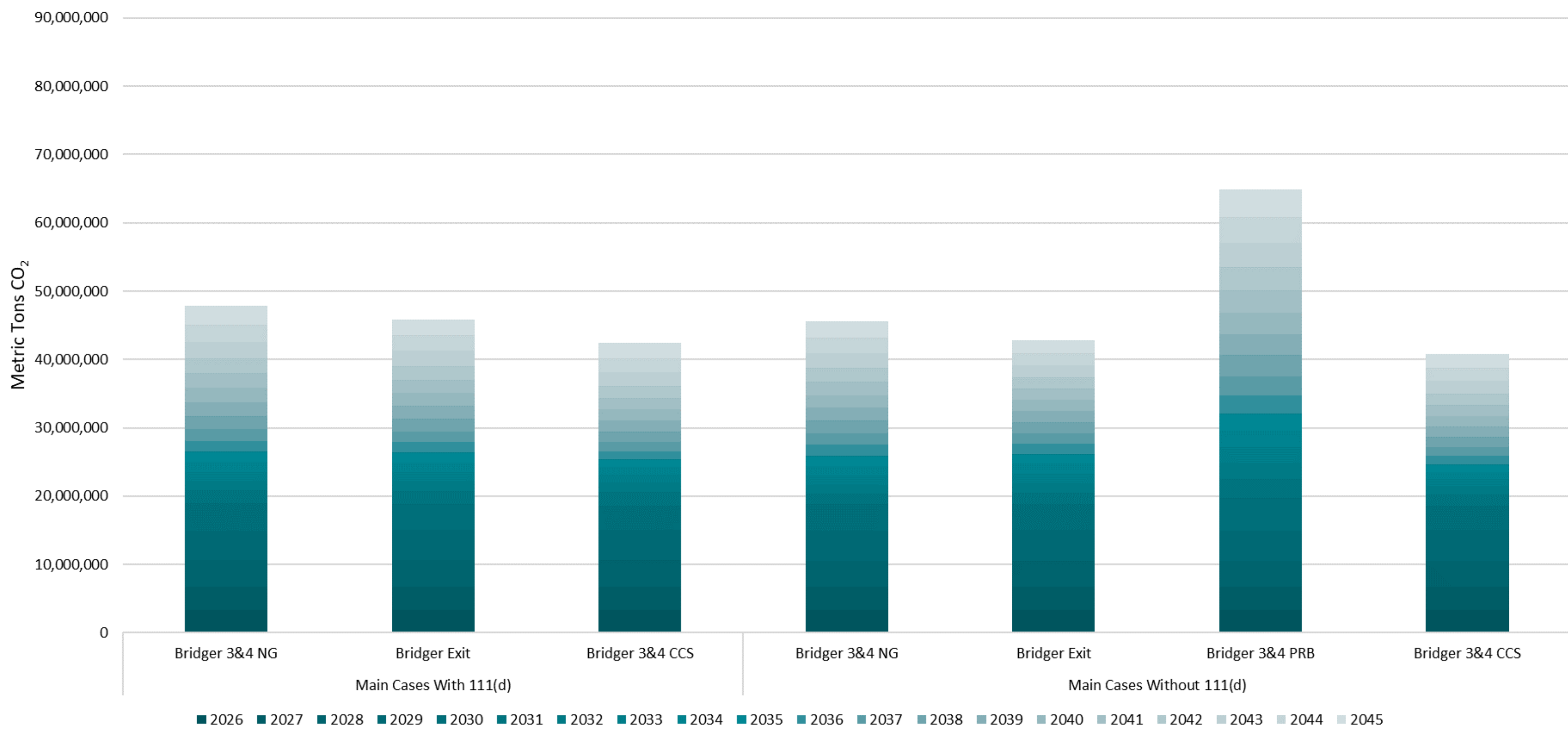


Figure 10.1 Estimated portfolio emissions from 2026–2045

In conclusion, the Preferred Portfolio (*With 111(d) Bridger 3&4*) strikes a balance of cost and risk while simultaneously reducing average annual planning conditions CO_2 emissions by more than 35% comparing the first five years of the plan to the last five years. The Preferred Portfolio also lays a cost-effective foundation to build upon for further CO_2 emissions reductions into the future. Idaho Power anticipates that technological advances will continue to occur to allow the company to reliably and cost-effectively move towards its goal of providing 100% clean energy by 2045.

For additional details on emissions (including details on SO_2 and NO_x emissions and information on scenario and sensitivity runs) for the 2025 IRP portfolios, please see the Portfolio Emissions Forecast section in *Appendix C—Technical Report.*

Qualitative Risk Analysis

Qualitative Risks

State and Federal Policy—There are many federal and state rules governing power supply and planning. The risk of future rules altering the economics of new resources or Idaho Power's electrical system composition is an important consideration. In 2025, there is an increased focus on energy related legislation and executive orders. Examples include rulings on the operations of carbon emitting resources, tariffs on goods and services, tax incentives and subsidies (and the repeal of such) for renewable generation, and PURPA rules governing renewable resource contracts. New or changed rules have implications for economics and system reliability, both of which impact customers.

For the 2025 IRP analysis, the following are considered to have high state and federal policy risk:

- Continued operations in coal resources
- Carbon capture technologies: the high resource cost and uncertainty regarding future tax credits

Fuel Supply—All generation resources require fuel to provide electricity. Fuel supply risks vary between resource types. Thermal resources like coal and natural gas rely on fuel supply infrastructure to produce and transport fuel by rail or pipeline and include mining or drilling facilities. New fuel supply chains, like hydrogen or advanced nuclear reactors, require new fuel which has yet to be developed at scale or at a commercially viable price.

Fuel supply infrastructure has several risks when evaluating resources; it can be susceptible to outages from weather, mechanical failures, etc.

For the portfolios analyzed in the 2025 IRP, there are some key fuel supply differences. Fuel source diversity helps reduce fuel supply risk. This is the case for portfolios that continue to leverage both coal and natural gas resources. To a lesser extent, portfolios that leverage regional diversity with natural gas sources also have lower relative fuel risk, as is the case when Bridger units 3 and 4 are converted to natural gas. Portfolios where Bridger units 3 and 4 are exited have relatively greater fuel risk because a larger portion of the company's natural gas resources would rely on the same natural gas hub.

Supply Chain—For the last several years, various components and products have encountered supply chain issues. Supply chain issues limit the availability of resources and increase financial risk because low supply results in higher costs. Supply chain issues can also impact the ability to acquire resources when they are needed.

Portfolios with developing technologies like carbon capture and portfolios that add many resources have a higher supply chain risk.

Market Volatility—Portfolios with resources that increase imports 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.

Some resources, such as natural gas and coal, can act as a hedge on market price volatility. Transmission can help reduce market volatility by allowing power to flow between regions during times of surplus or need. Storage resources can benefit from market volatility through arbitrage (charging at times when market prices are low and discharging when market prices are high).

Siting and Permitting—All generation and transmission resources in the portfolios require siting and permitting. The associated processes can be 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 footprints have a higher risk. All supply-side resources have some level of this qualitative risk.

Portfolios with high resource builds have a higher level of siting and permitting risk.

Emerging Technology—New or developing technologies have the potential to underperform relative to expectations (cost, operational characteristics, time to market, etc.). These risks can be difficult to predict and manage, as the technologies are often new and untested.

Carbon capture, SMRs, hydrogen, and 100-hour storage are all developing technologies and carry an increased measure of emerging technology risk.

Partnerships—Idaho Power is a partner in generation facilities and is jointly developing 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.

Qualitative Risks Comparison

Each resource alternative possesses 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 against the potential outcomes for each resource and the portfolio of resources in aggregate. Idaho Power considered how qualitative risks affect each resource portfolio. Although the qualitative risk analysis performed is expansive, it is not exhaustive. For brevity, Idaho Power has limited the qualitative risk analysis to those risks that are typical within the power industry and accordingly does not consider exceedingly rare or hypothetical "black swan" events when performing qualitative risk analysis.

For purposes of risk assessment, each portfolio and risk is assigned a low-, medium-, or high-risk level. Consideration was given to both the likelihood and potential impact of each risk. The results of Idaho Power's qualitative risk assessment are presented in Table 10.5.

Table 10.5 Qualitative risk comparison

Portfolio	State/Federal Policy	Fuel Supply	Supply Chain	Market Volatility	Siting and Permitting	Emerging Technology	Partnerships
With 111(d) Bridger 3&4 NG	Medium	Medium	Medium	Medium	Low	Low	Medium
With 111(d) Bridger 3&4 Exit	Medium	High	Medium	Medium	Medium	Medium	Low
With 111(d) Bridger 3&4 CCS	High	Low	High	Low	Low	High	Medium
With 111(d) No Gas 2029	Medium	Medium	High	High	High	Low	Medium
With 111(d) No Gas 2029/2030	Medium	Low	High	High	High	Medium	Medium
Without 111(d) Bridger 3&4 PRB	High	Low	Low	Low	Low	Low	Medium
Without 111(d) Bridger 3&4 NG	Medium	Medium	Medium	Medium	Low	Low	Medium
Without 111(d) Bridger 3&4 CCS	High	Low	High	Low	Low	High	Medium
Without 111(d) Bridger 3&4 Exit	Medium	High	Medium	Medium	Medium	Medium	Low

Stochastic Risk Analysis

The stochastic risk analysis assesses the effect on portfolio costs when select variables have values that change 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 help understand the deviation of portfolio costs across the full extent of stochastic variation. To assess stochastic risk, the key drivers of natural gas prices, customer load, hydroelectric generation, carbon prices, and REC price forecasts are allowed to change based on their historical or predicted variance. A full description of how these variables were modeled in the stochastic analysis can be found in the Stochastic Risk Analysis section of *Appendix C—Technical Report*.

In Figure 10.2, each line represents the likelihood of occurrence by total portfolio NPV. Higher values on the line represent a higher probability of occurrence, with values near the horizontal axis representing improbable events. Values that occur toward the left have lower cost, while values toward the right have higher cost. As indicated by the peak of the graph being furthest left, the results of the stochastic analysis show that the Preferred Portfolio (*With 111(d) Bridger 3&4 NG*) has a similar risk profile to the *Low Gas Price* and *Forced SCCT 2030* portfolios. A detailed look at the results shows that the Preferred Portfolio performs the best in the stochastic analysis but the similarity of the kernels reflects the similarity of the portfolios overall. Consistent with the portfolio cost analysis, of the Bridger 3&4 options, the conversion of units 3&4 to natural gas performs the best followed by the exit of Bridger 3&4 and the worst performing is the *Bridger 3&4 CCS* portfolio. Of the no gas options tested, all performed poorly compared to the Preferred Portfolio as reflected by their significant right shift in Figure 10.2. Further details on the stochastic results, including non-111(d) cases, can be found in the Stochastic Risk Analysis section of *Appendix C—Technical Report*. Based on the results of the stochastic analysis, the selection of the *With 111(d) Bridger 3&4 NG* as the Preferred Portfolio is well supported.

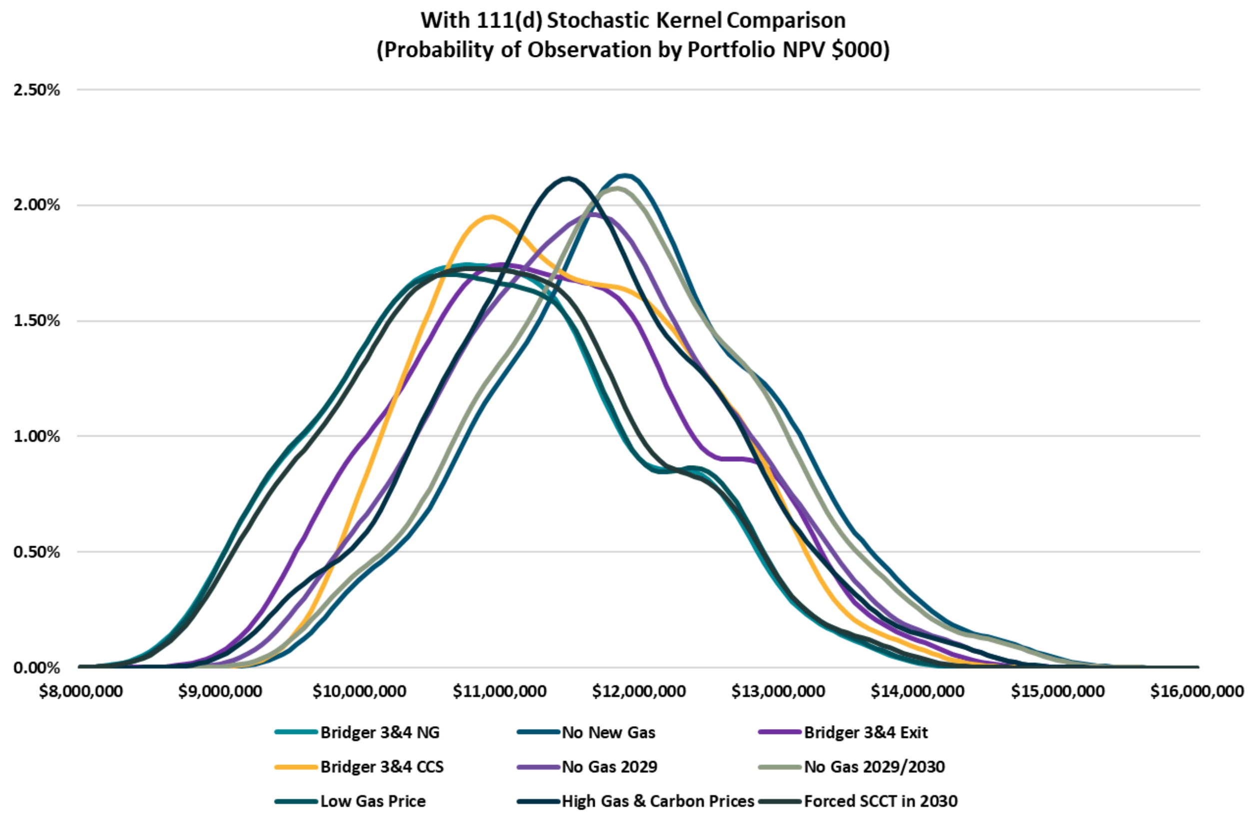


Figure 10.2 NPV stochastic probability kernel—Preferred Portfolio contenders (likelihood by NPV [$ x 1,000])

Loss of Load Expectation Based Reliability Evaluation of Portfolios

As a post-processing reliability evaluation, Idaho Power utilized the RCAT to calculate the annual capacity positions of all Aurora-produced portfolios to ensure the 20-year load and resource buildouts achieved the pre-determined reliability threshold.

The annual capacity position is obtained by averaging the resulting size of a perfect generating unit required to achieve a 0.1 event-days per year LOLE from each of the RCAT's seven test years. If the LOLE-derived reliability evaluation found any select portfolio to have one or more years that resulted in a capacity shortfall, the company recalibrated the seasonal PRM points in Aurora and reran the LTCE which would again be tested for reliability.

The LOLE-derived evaluation is a minimum requirement for portfolios to be considered reliable from a capacity perspective, however, there are other factors that drive resource selections and the resulting annual capacity positions. The Aurora LTCE model can select resources to address regulation reserves and energy requirements. Also, while VERs and energy-limited resources (ELR) can be added in more granular increments to meet the different Aurora LTCE requirements, other resources (i.e., natural gas units, coal-to-gas conversions, and hydrogen units) must be selected at their identified nameplate capacity and at a specific time.

Historically, Idaho Power has been capacity constrained, meaning peak capacity was the driving factor for acquiring resources. However, with the increased penetration of energy storage, energy needs and economics can also drive resource additions.

More information on the LOLE-derived capacity position calculation can be found in the System Reliability Modeling—Portfolio Analysis section of *Appendix D—System Reliability and Regulating Reserves*.

Annual Capacity Positions of the Preferred Portfolio

The annual capacity positions after resource additions for the Preferred Portfolio are provided in Table 10.6, which shows an annual position of capacity length for all 20 years of the planning period, thus meeting the company's reliability threshold. As previously stated, the regulating requirements, resource size, energy needs, resource economics and other factors that are modeled in the Aurora LTCE model can influence the resulting annual capacity position calculation.

Table 10.6 Preferred Portfolio annual capacity positions (MW)

Year	With 111(d) & Bridger 3 & 4 Natural Gas	
2026	66	Length
2027	47	Length
2028	22	Length
2029	66	Length
2030	222	Length
2031	302	Length
2032	187	Length
2033	151	Length
2034	161	Length
2035	232	Length
2036	212	Length
2037	173	Length
2038	131	Length
2039	94	Length
2040	68	Length
2041	78	Length
2042	55	Length
2043	60	Length
2044	64	Length
2045	64	Length

All portfolios were tested for reliability and were in a position of capacity length for all 20 years of the planning period.

11. PREFERRED PORTFOLIO AND NEAR-TERM ACTION PLAN

Preferred Portfolio

The 2025 IRP scenario analysis strategy focused on key near-term decisions and varying sensitivities to ensure that it had identified an optimal solution specific to Idaho Power and its customers. The company identified main cases with resource buildouts driven by the outcome of the EPA 111(d) rule, options for Bridger units 3 and 4, and varying amounts of additional customer demand. Once portfolio buildouts were generated, to evaluate future cost risks, the company performed a cost analysis for the main cases by performing a stochastic analysis on the portfolios (see Chapter 10).

The company also evaluated the qualitative risks and the reliability of each of the main cases (see Chapter 10).

Using the Preferred Portfolio (*With 111(d) Bridger 3&4 NG*), the company developed additional portfolios to do the following:

1. Evaluate risk associated with different futures and sensitivities (discussed later in this Chapter)
2. Perform validation and verification tests to ensure the model selects the optimal set of resources

The Preferred Portfolio (*With 111(d) Bridger 3&4 NG*) follows.

Table 11.1 Preferred Portfolio (*With 111(d) Bridger 3&4 NG*) resource selections

Preferred Portfolio (MW)											
Year	Coal Exits	Conv. Gas	New Gas	Wind	Solar	4Hr	100Hr	Trans.	DR	EE Forecast	EE Bundles
2026	-134	261	0	0	125	250	0	0	0	18	0
2027	0	0	0	600	420	100	0	0	0	14	0
2028	0	0	0	0	100	200	0	B2H	0	15	0
2029	0	0	150	100	0	155	0	SWIP-N	10	16	0
2030	-350	350	300	0	100	0	0	0	0	16	0
2031	0	0	0	0	400	0	0	0	0	17	8
2032	0	0	0	0	200	0	0	0	0	17	0
2033	0	0	0	0	100	50	0	0	0	17	21
2034	0	0	0	0	0	0	0	0	0	16	6
2035	0	0	0	0	0	0	0	0	0	16	5
2036	0	0	0	0	0	0	0	0	0	16	5
2037	0	0	0	0	0	0	0	0	0	15	0
2038	0	0	0	0	0	0	0	0	0	14	0
2039	0	0	0	0	0	0	0	0	0	13	0
2040	0	0	0	0	0	5	0	0	0	12	0
2041	0	0	50	0	0	5	0	0	0	12	0
2042	0	0	0	0	0	5	0	0	10	11	3
2043	0	0	50	0	0	5	0	0	0	11	0
2044	0	0	0	0	0	55	0	0	0	11	7
2045	0	0	0	0	0	5	50	0	0	8	2
Subtotal[28]	-484	611	550	700	1,445	835	50		20	287	58
Total	**4,071**	**Portfolio Cost: $10,966M**									

The following items are included in Table 11.1:

- The addition of 1,445 MW of solar generation, including expected solar projects and solar to support the energy needs of large industrial customers under the CEYW program. This number includes the solar projects already contracted for completion in 2026 and 2027.
- The conversion of Valmy units 1 and 2 (a combined 261 MW) occurs in 2026. Because Idaho Power exited coal operations at Valmy Unit 1, only Valmy Unit 2 is shown in that year as a coal exit. These units operate through the planning timeframe.

[28] Subtotal and annual increments in the table do not show the base forecast associated with forecasted new PURPA and PURPA contract renegotiations. For this information, refer to *Appendix C—Technical Report*.

- The conversion of Bridger units 3 and 4 (a combined 350 MW) is shown as a coal exit and a gas addition in 2030. These units operate through the planning timeframe.
- A total of 700 MW of wind projects are identified, 600 MW in 2027 and 100 MW in 2029. The 600 MW of wind, Jackalope, is already contracted.
- A total of 835 MW of 4-hour energy storage, which includes the energy storage projects already contracted for completion in 2026 and 2027.
- The B2H and SWIP-N transmission lines are represented in the Trans. column in 2028 for B2H (expected late 2027) and 2029 for SWIP-N (expected 2028).
- An incremental 20 MW of DR represents an expansion of the company's existing programs.
- The EE Forecast column shows a total of 287 MW of cost-effective EE measures that will be added to Idaho Power's system to meet growing energy needs. These EE measures were identified in the EE Potential Assessment.
- An incremental 58 MW of EE bundles are identified throughout the planning timeframe.
- 150 MW in 2029 and 300 MW in 2030 of new natural gas, as well as 100 MW in later years, are selected in the planning timeframe.
- An addition of 50 MW of 100-hour energy storage is included in 2045.

Preferred Portfolio and the EPA Rule 111(d) Considerations

At the time of the 2025 IRP filing, the EPA Rule 111(d) was in effect. Given the current active review and the possibility the EPA Rule may be revoked or substantially altered, the company analyzed portfolios without the rule. In the event the rule is revoked, the Preferred Portfolio may shift from the With 111(d) Bridger 3&4 NG portfolio to one of the following portfolios:

- Without 111(d) Bridger 3&4 NG
- Without 111(d) Bridger 3&4 PRB

These portfolios performed similarly in the analysis with portfolio costs that differed by less than $100M.

Table 11.2 Without 111(d) Bridger 3&4 NG resource selections

Without 111(d) Bridger 3&4 NG (MW)											
Year	Coal Exits	Conv. Gas	New Gas	Wind	Solar	4Hr	100Hr	Trans.	DR	EE Forecast	EE Bundles
2026	-134	261	0	0	125	250	0	0	0	18	0
2027	0	0	0	600	420	100	0	0	0	14	0
2028	0	0	0	0	100	200	0	B2H	0	15	0
2029	0	0	150	100	0	155	0	SWIP-N	10	16	0
2030	-350	350	300	0	100	0	0	0	0	16	9
2031	0	0	0	0	400	0	0	0	0	17	8
2032	0	0	0	0	200	0	0	0	0	17	24
2033	0	0	0	0	0	0	0	0	0	17	21
2034	0	0	0	0	0	0	0	0	0	16	0
2035	0	0	0	0	0	0	0	0	0	16	0
2036	0	0	0	0	0	0	0	0	0	16	0
2037	0	0	0	0	0	0	0	0	0	15	4
2038	0	0	0	0	0	0	0	0	0	14	4
2039	0	0	0	0	100	50	0	0	0	13	4
2040	0	0	0	0	0	0	0	0	0	12	3
2041	0	0	50	0	0	0	0	0	0	12	8
2042	0	0	0	0	0	5	0	0	0	11	0
2043	0	0	50	0	0	5	0	0	0	11	3
2044	0	0	50	0	0	0	0	0	0	11	3
2045	0	0	50	0	0	0	0	0	0	8	0
Subtotal	-484	611	650	700	1,445	765	0		10	287	91
Total	**4,074**	**Portfolio Cost: $10,782M**									

Table 11.3 Without 111(d) Bridger 3&4 PRB resource selections

Without 111(d) Bridger 3&4 PRB (MW)											
Year	Coal Exits	Conv. Gas	New Gas	Wind	Solar	4Hr	100Hr	Trans.	DR	EE Forecast	EE Bundles
2026	-134	261	0	0	125	250	0	0	0	18	0
2027	0	0	0	600	420	100	0	0	0	14	0
2028	0	0	0	0	100	200	0	B2H	0	15	0
2029	0	0	150	100	0	155	0	SWIP-N	10	16	0
2030	0	0	300	0	100	0	0	0	0	16	0
2031	0	0	0	0	400	0	0	0	0	17	0
2032	0	0	0	0	200	0	0	0	0	17	0
2033	0	0	0	0	0	0	0	0	0	17	0
2034	0	0	0	0	0	0	0	0	0	16	0
2035	0	0	0	0	0	0	0	0	0	16	0
2036	0	0	0	0	0	0	0	0	0	16	0
2037	0	0	0	0	0	5	0	0	0	15	0
2038	0	0	0	0	0	0	0	0	0	14	0
2039	0	0	0	0	0	5	0	0	0	13	0
2040	0	0	0	0	0	5	0	0	0	12	0
2041	0	0	50	0	0	5	0	0	0	12	0
2042	0	0	0	0	0	55	0	0	0	11	0
2043	0	0	50	0	0	0	0	0	0	11	0
2044	0	0	0	0	0	0	50	0	0	11	0
2045	0	0	0	0	0	0	50	0	0	8	0
Subtotal	-134	261	550	700	1,345	780	100		10	287	0
Total	**3,898**	**Portfolio Cost: $10,684M**									

Preferred Portfolio Compared to Varying Future Scenarios

For each of the listed future scenarios, see a side-by-side comparison with the Preferred Portfolio starting with Table 11.2.

High Gas & Carbon Prices

This portfolio of resources was optimized for a future where gas prices throughout the WECC were increased by low supply of natural gas. A carbon price forecast was added to the WECC for those regions that aren't already subject to a carbon cost.

Natural gas resources are still selected in 2029 and 2030 as a cost-effective way to meet the forecasted demand. However, in this scenario, more renewable resources are added, starting in the year 2031, and extending through the end of the planning timeframe. These resources are optimal in a High Gas & Carbon Prices future to supply low-cost energy and offset energy produced from natural gas resources.

It should be noted that the conditions given in this scenario (high gas price and aggressive carbon adder forecasts) were applied to the entire WECC. Emissions of this portfolio are lower than the emissions of the planning scenario, as expected.

Low Gas Price

Similar to the prior scenario, the *Low Gas Price* scenario includes adjustments to the natural gas price forecast for the entire WECC. In a scenario where natural gas prices are low, this scenario shows few differences in resource selection from the planning case. Emissions from this portfolio are higher than the emissions of the planning scenario, as expected.

Constrained Markets

In the Constrained Markets scenario, in response to modeled limited access to energy markets throughout the WECC, an additional 900 MW of solar, 370 MW of 4-hour battery storage, 100 MW of wind, and 184 MW of energy efficiency measures were selected. These resources were considered optimal if market access is restricted. The need for natural gas capacity was reduced 50 MW by the addition of other resources.

100% Clean by 2045

Idaho Power established a 100% clean energy scenario. A comparison of resources selected in the Preferred Portfolio compared to the resource selection that represents one possible path that leads to the goal's fulfillment is shown in the following table. The path to clean energy may not be linear and these assumptions were made to create a comparison scenario.

Even in this scenario, additional natural gas resources are cost-effective measures to meet near-term load growth and ensure reliability throughout the plan timeframe. As the plan progresses and natural gas plants are converted to a carbon free fuel source, solar coupled with storage is added to provide low-cost energy and offset the high cost of carbon free fuel.

No PURPA Replacement Contracts

Consistent with the description in chapter 9, this portfolio assumes PURPA contracts do not renew and there is no forecast of future PURPA. The portfolio build comparison is below.

This scenario and forecast shine a light on any deficits that may not otherwise be identified, and therefore increases the nameplate amount of capacity that would need to be acquired to meet increasing energy demand. The first key difference occurs in 2029, where some additional solar and storage is necessary to fill the gap from assumed PURPA renewals. Throughout the planning timeframe, an additional 250 MW of natural gas resources, 300 MW of solar, 145 MW of 4-hour battery storage, and 40 MW of energy efficiency measures are selected to cover the deficits left by PURPA expired contracts.

Extreme Weather

In this scenario, the company modeled consistent high demand associated with extreme temperature events (95th percentile). While varying water supply is expected into the future, low water supply (30th percentile) was used in this scenario to test the adequacy of the remaining resources. These extremes were modeled for the entire IRP timeframe.

To meet the increased demand associated with extreme weather events, more than 2,000 MW of resources were selected. These resources included 700 MW of solar, 835 MW of 4-hour battery storage, 500 MW of wind, and 130 MW of energy efficiency measures.
Other differences include a 30 MW geothermal resource in 2044 and a decrease of 150 MW in natural gas resources.

High Resource Costs

The *High Resource Costs* scenario uses the conservative cost curves from NREL's ATB and eliminates the PTC and ITC where applicable. Assuming higher resource costs into the future makes this scenario directionally informative when considering unknowns such as tariffs, tax credit repeals, and other events that put upward pressure on resource costs.

A 100 MW increase in the quantity of natural gas generation and a 130 MW decrease in the quantity of 4-hour battery storage result from the increased price outlook for solar, wind, and storage. Energy efficiency measures also decrease by 20 MW.

No SWIP

The 2025 IRP model includes Idaho Power's interest in the SWIP-N transmission line, connecting Idaho Power to energy markets in the Southwest, and providing Idaho Power access to 500 MW of capacity in the winter months, starting in 2028.

This scenario shows that a large amount of resources are required to sufficiently replace the market access that SWIP-N affords. These resources include an additional 500 MW of wind, 600 MW of solar, and 805 MW of 4-hour battery storage. An additional 113 MW of energy efficiency measures are also selected in the absence of SWIP-N.

Load Shift

For the details of the changes made to load, solar and storage resources in this scenario, please see the description in chapter 9.

These changes are reflected in the following side-by-side table showing the Preferred Portfolio next to this Load Shift scenario. The changes resulted in a cost decrease of $27 M, which includes the cost difference of adding 100 MW of solar and removing 100 MW of 4-hour battery storage. The cost difference does not reflect the cost of the 100 MW load shift program for the duration of the plan.

Table 11.4 Preferred Portfolio—High Gas & Carbon Prices comparison table

	Preferred Portfolio (MW)									High Gas & Carbon Prices (MW)								
Year	Coal Exits	Gas/H2	Wind	Solar	Storage	Trans.	DR	EE	GN*	Coal Exits	Gas/H2	Wind	Solar	Storage	Trans.	DR	EE	GN*
2026	-134	261	0	125	250	0	0	18	0	-134	261	0	125	250	0	0	18	0
2027	0	0	600	420	100	0	0	14	0	0	0	600	420	100	0	0	14	0
2028	0	0	0	100	200	B2H	0	15	0	0	0	0	100	200	B2H	0	15	0
2029	0	150	100	0	155	SWIP-N	10	16	0	0	150	100	0	155	SWIP-N	10	16	0
2030	-350	650	0	100	0	0	0	16	0	-350	500	0	100	0	0	0	46	0
2031	0	0	0	400	0	0	0	25	0	0	0	0	600	100	0	0	59	0
2032	0	0	0	200	0	0	0	17	0	0	0	0	200	5	0	0	41	0
2033	0	0	0	100	50	0	0	38	0	0	0	0	100	55	0	10	51	0
2034	0	0	0	0	0	0	0	22	0	0	0	0	0	0	0	0	36	0
2035	0	0	0	0	0	0	0	21	0	0	0	0	100	50	0	0	33	0
2036	0	0	0	0	0	0	0	20	0	0	0	0	300	150	0	0	20	0
2037	0	0	0	0	0	0	0	15	0	0	0	0	600	300	0	0	19	0
2038	0	0	0	0	0	0	0	14	0	0	0	0	100	50	0	0	18	0
2039	0	0	0	0	0	0	0	13	0	0	0	0	100	50	0	0	17	0
2040	0	0	0	0	5	0	0	12	0	0	0	0	0	0	0	0	16	0
2041	0	50	0	0	5	0	0	12	0	0	0	0	100	50	0	0	19	0
2042	0	0	0	0	5	0	10	14	0	0	50	0	100	50	0	0	14	0
2043	0	50	0	0	5	0	0	11	0	0	0	0	300	155	0	0	11	0
2044	0	0	0	0	55	0	0	18	0	0	0	0	100	55	0	0	11	0
2045	0	0	0	0	55	0	0	11	0	0	50	0	200	100	0	0	14	0
Sub Total	-484	1,161	700	1,445	885		20	344	0	-484	1,011	700	3,645	1,875		20	489	0
Total	**4,071**									**7,256**								
Portfolio Cost ($ x 1,000,000):		**$10,966**								**$14,167**								

*Geothermal Nuclear

Table 11.5 Preferred Portfolio—Low Gas Price comparison table

	Preferred Portfolio (MW)									Low Gas Price (MW)								
Year	Coal Exits	Gas/H2	Wind	Solar	Storage	Trans.	DR	EE	GN*	Coal Exits	Gas/H2	Wind	Solar	Storage	Trans.	DR	EE	GN*
2026	-134	261	0	125	250	0	0	18	0	-134	261	0	125	250	0	0	18	0
2027	0	0	600	420	100	0	0	14	0	0	0	600	420	100	0	0	14	0
2028	0	0	0	100	200	B2H	0	15	0	0	0	0	100	200	B2H	0	15	0
2029	0	150	100	0	155	SWIP-N	10	16	0	0	150	0	100	205	SWIP-N	0	16	0
2030	-350	650	0	100	0	0	0	16	0	-350	650	0	100	0	0	0	16	0
2031	0	0	0	400	0	0	0	25	0	0	0	0	400	0	0	0	25	0
2032	0	0	0	200	0	0	0	17	0	0	0	0	200	0	0	0	24	0
2033	0	0	0	100	50	0	0	38	0	0	0	0	100	50	0	0	23	0
2034	0	0	0	0	0	0	0	22	0	0	0	0	0	0	0	0	36	0
2035	0	0	0	0	0	0	0	21	0	0	0	0	0	0	0	0	33	0
2036	0	0	0	0	0	0	0	20	0	0	0	0	0	0	0	0	16	0
2037	0	0	0	0	0	0	0	15	0	0	0	0	0	0	0	0	15	0
2038	0	0	0	0	0	0	0	14	0	0	0	0	0	0	0	0	14	0
2039	0	0	0	0	0	0	0	13	0	0	0	0	0	0	0	0	13	0
2040	0	0	0	0	5	0	0	12	0	0	0	0	0	0	0	0	12	0
2041	0	50	0	0	5	0	0	12	0	0	50	0	0	5	0	0	12	0
2042	0	0	0	0	5	0	10	14	0	0	0	0	0	5	0	0	11	0
2043	0	50	0	0	5	0	0	11	0	0	50	0	0	0	0	10	11	0
2044	0	0	0	0	55	0	0	18	0	0	0	0	0	55	0	0	11	0
2045	0	0	0	0	55	0	0	11	0	0	50	0	0	5	0	0	14	0
Sub Total	-484	1,161	700	1,445	885		20	344	0	-484	1,211	600	1,545	875		10	350	0
Total	**4,071**									**4,107**								
Portfolio Cost ($ x 1,000,000):		**$10,966**								**$10,162**								

*Geothermal Nuclear

Table 11.6 Preferred Portfolio—Constrained Markets comparison table

	Preferred Portfolio (MW)									Constrained Markets (MW)								
Year	Coal Exits	Gas/H2	Wind	Solar	Storage	Trans.	DR	EE	GN*	Coal Exits	Gas/H2	Wind	Solar	Storage	Trans.	DR	EE	GN*
2026	-134	261	0	125	250	0	0	18	0	-134	261	0	125	250	0	0	18	0
2027	0	0	600	420	100	0	0	14	0	0	0	600	420	100	0	0	14	0
2028	0	0	0	100	200	B2H	0	15	0	0	0	0	100	200	B2H	0	15	0
2029	0	150	100	0	155	SWIP-N	10	16	0	0	150	0	300	250	SWIP-N	0	16	0
2030	-350	650	0	100	0	0	0	16	0	-350	500	0	100	0	0	0	46	0
2031	0	0	0	400	0	0	0	25	0	0	0	0	400	0	0	0	59	0
2032	0	0	0	200	0	0	0	17	0	0	0	0	200	0	0	0	41	0
2033	0	0	0	100	50	0	0	38	0	0	50	0	0	0	0	0	51	0
2034	0	0	0	0	0	0	0	22	0	0	0	0	100	50	0	0	47	0
2035	0	0	0	0	0	0	0	21	0	0	0	200	100	150	0	0	33	0
2036	0	0	0	0	0	0	0	20	0	0	0	0	0	0	0	0	20	0
2037	0	0	0	0	0	0	0	15	0	0	0	0	0	0	0	0	28	0
2038	0	0	0	0	0	0	0	14	0	0	0	0	0	0	0	0	26	0
2039	0	0	0	0	0	0	0	13	0	0	0	0	0	0	0	0	24	0
2040	0	0	0	0	5	0	0	12	0	0	0	0	100	50	0	0	22	0
2041	0	50	0	0	5	0	0	12	0	0	50	0	0	0	0	10	15	0
2042	0	0	0	0	5	0	10	14	0	0	0	0	0	5	0	10	19	0
2043	0	50	0	0	5	0	0	11	0	0	50	0	0	0	0	0	14	0
2044	0	0	0	0	55	0	0	18	0	0	0	0	300	150	0	0	11	0
2045	0	0	0	0	55	0	0	11	0	0	50	0	100	50	0	0	8	0
Sub Total	-484	1,161	700	1,445	885		20	344	0	-484	1,111	800	2,345	1,255		20	527	0
Total	**4,071**									**5,574**								
Portfolio Cost ($ x 1,000,000):			**$10,966**							**$12,586**								

*Geothermal Nuclear

Table 11.7 Preferred Portfolio—100% Clean by 2045 comparison table

	Preferred Portfolio (MW)									100% Clean by 2045 (MW)								
Year	Coal Exits	Gas/H2	Wind	Solar	Storage	Trans.	DR	EE	GN*	Coal Exits	Gas/H2	Wind	Solar	Storage	Trans.	DR	EE	GN*
2026	-134	261	0	125	250	0	0	18	0	-134	261	0	125	250	0	0	18	0
2027	0	0	600	420	100	0	0	14	0	0	0	600	420	100	0	0	14	0
2028	0	0	0	100	200	B2H	0	15	0	0	0	0	100	200	B2H	0	15	0
2029	0	150	100	0	155	SWIP-N	10	16	0	0	150	200	100	200	SWIP-N	0	16	0
2030	-350	650	0	100	0	0	0	16	0	-350	500	0	100	0	0	0	46	0
2031	0	0	0	400	0	0	0	25	0	0	0	0	400	0	0	0	43	0
2032	0	0	0	200	0	0	0	17	0	0	0	0	200	0	0	0	55	0
2033	0	0	0	100	50	0	0	38	0	0	0	100	200	150	0	0	38	0
2034	0	0	0	0	0	0	0	22	0	0	0	0	0	0	0	0	47	0
2035	0	0	0	0	0	0	0	21	0	0	0	0	200	100	0	0	21	0
2036	0	0	0	0	0	0	0	20	0	0	0	0	200	100	0	0	20	30
2037	0	0	0	0	0	0	0	15	0	0	0	0	200	100	0	0	19	0
2038	0	0	0	0	0	0	0	14	0	0	0	0	300	150	0	0	26	0
2039	0	0	0	0	0	0	0	13	0	0	0	0	0	0	0	0	13	0
2040	0	0	0	0	5	0	0	12	0	0	0	0	300	150	0	0	12	0
2041	0	50	0	0	5	0	0	12	0	0	0	0	200	100	0	0	12	0
2042	0	0	0	0	5	0	10	14	0	0	0	0	600	300	0	0	11	0
2043	0	50	0	0	5	0	0	11	0	0	0	0	400	200	0	0	11	0
2044	0	0	0	0	55	0	0	18	0	0	0	0	200	100	0	0	11	0
2045	0	0	0	0	55	0	0	11	0	0	0	0	200	105	0	0	11	0
Sub Total	-484	1,161	700	1,445	885		20	344	0	-484	911	900	4,445	2,305		0	461	30
Total	**4,071**									**8,568**								
Portfolio Cost ($ x 1,000,000):		**$10,966**								**$13,387**								

*Geothermal Nuclear

Table 11.8 Preferred Portfolio—No PURPA Replacement Contracts comparison table

	Preferred Portfolio (MW)									No PURPA Replacement (MW)								
Year	Coal Exits	Gas/H2	Wind	Solar	Storage	Trans.	DR	EE	GN*	Coal Exits	Gas/H2	Wind	Solar	Storage	Trans.	DR	EE	GN*
2026	-134	261	0	125	250	0	0	18	0	-134	261	0	125	250	0	0	18	0
2027	0	0	600	420	100	0	0	14	0	0	0	600	420	100	0	0	14	0
2028	0	0	0	100	200	B2H	0	15	0	0	0	0	100	200	B2H	0	15	0
2029	0	150	100	0	155	SWIP-N	10	16	0	0	150	0	100	255	SWIP-N	10	16	0
2030	-350	650	0	100	0	0	0	16	0	-350	500	0	100	0	0	0	16	0
2031	0	0	0	400	0	0	0	25	0	0	0	0	400	0	0	0	25	0
2032	0	0	0	200	0	0	0	17	0	0	300	0	200	0	0	0	17	0
2033	0	0	0	100	50	0	0	38	0	0	0	0	0	0	0	0	38	0
2034	0	0	0	0	0	0	0	22	0	0	0	0	0	0	0	0	22	0
2035	0	0	0	0	0	0	0	21	0	0	0	0	0	0	0	0	21	0
2036	0	0	0	0	0	0	0	20	0	0	0	0	0	0	0	0	20	0
2037	0	0	0	0	0	0	0	15	0	0	0	0	0	0	0	0	15	0
2038	0	0	0	0	0	0	0	14	0	0	0	0	0	5	0	0	14	0
2039	0	0	0	0	0	0	0	13	0	0	0	0	0	5	0	0	13	0
2040	0	0	0	0	5	0	0	12	0	0	0	0	0	5	0	10	12	0
2041	0	50	0	0	5	0	0	12	0	0	50	0	0	5	0	0	12	0
2042	0	0	0	0	5	0	10	14	0	0	0	0	0	5	0	0	14	0
2043	0	50	0	0	5	0	0	11	0	0	50	0	0	5	0	0	11	0
2044	0	0	0	0	55	0	0	18	0	0	0	0	0	5	0	0	18	0
2045	0	0	0	0	55	0	0	11	0	0	0	0	0	50	0	0	11	0
Sub Total	-484	1,161	700	1,445	885		20	344	0	-484	1,311	600	1,445	890		20	3844	0
Total	**4,071**									**4,126**								
Portfolio Cost ($ x 1,000,000):		**$10,966**								**$11,216**								

*Geothermal Nuclear

Table 11.9 Preferred Portfolio—Extreme Weather comparison table

	Preferred Portfolio (MW)									Extreme Weather (MW)								
Year	Coal Exits	Gas/H2	Wind	Solar	Storage	Trans.	DR	EE	GN*	Coal Exits	Gas/H2	Wind	Solar	Storage	Trans.	DR	EE	GN*
2026	-134	261	0	125	250	0	0	18	0	-134	261	0	125	250	0	0	18	0
2027	0	0	600	420	100	0	0	14	0	0	0	600	420	100	0	0	14	0
2028	0	0	0	100	200	B2H	0	15	0	0	0	0	100	200	B2H	0	15	0
2029	0	150	100	0	155	SWIP-N	10	16	0	0	150	600	400	955	SWIP-N	0	16	0
2030	-350	650	0	100	0	0	0	16	0	-350	400	0	100	0	0	0	25	0
2031	0	0	0	400	0	0	0	25	0	0	150	0	400	0	0	0	25	0
2032	0	0	0	200	0	0	0	17	0	0	0	0	200	0	0	0	24	0
2033	0	0	0	100	50	0	0	38	0	0	0	0	0	0	0	0	23	0
2034	0	0	0	0	0	0	0	22	0	0	0	0	0	0	0	0	36	0
2035	0	0	0	0	0	0	0	21	0	0	0	0	0	0	0	0	43	0
2036	0	0	0	0	0	0	0	20	0	0	0	0	0	0	0	0	40	0
2037	0	0	0	0	0	0	0	15	0	0	0	0	300	150	0	0	36	0
2038	0	0	0	0	0	0	0	14	0	0	0	0	100	50	0	0	26	0
2039	0	0	0	0	0	0	0	13	0	0	0	0	0	0	0	0	24	0
2040	0	0	0	0	5	0	0	12	0	0	0	0	0	5	0	0	29	0
2041	0	50	0	0	5	0	0	12	0	0	50	0	0	0	0	0	19	0
2042	0	0	0	0	5	0	10	14	0	0	0	0	0	0	0	0	19	0
2043	0	50	0	0	5	0	0	11	0	0	0	0	0	5	0	0	18	0
2044	0	0	0	0	55	0	0	18	0	0	0	0	0	0	0	0	14	30
2045	0	0	0	0	55	0	0	11	0	0	0	0	0	5	0	0	8	0
Sub Total	-484	1,161	700	1,445	885		20	344	0	-484	1,011	1,200	2,145	1,720		0	474	30
Total	**4,071**									**6,095**								
Portfolio Cost ($ x 1,000,000):		**$10,966**								**$13,712**								

*Geothermal Nuclear

Table 11.10 Preferred Portfolio—High Resource Costs comparison table

	Preferred Portfolio (MW)									High Resource Costs (MW)								
Year	Coal Exits	Gas/H2	Wind	Solar	Storage	Trans.	DR	EE	GN*	Coal Exits	Gas/H2	Wind	Solar	Storage	Trans.	DR	EE	GN*
2026	-134	261	0	125	250	0	0	18	0	-134	261	0	125	250	0	0	18	0
2027	0	0	600	420	100	0	0	14	0	0	0	600	420	100	0	0	14	0
2028	0	0	0	100	200	B2H	0	15	0	0	0	0	100	200	B2H	0	15	0
2029	0	150	100	0	155	SWIP-N	10	16	0	0	150	100	0	155	SWIP-N	10	16	0
2030	-350	650	0	100	0	0	0	16	0	-350	650	0	100	0	0	0	16	0
2031	0	0	0	400	0	0	0	25	0	0	0	0	400	0	0	0	25	0
2032	0	0	0	200	0	0	0	17	0	0	0	0	200	0	0	0	24	0
2033	0	0	0	100	50	0	0	38	0	0	0	0	100	50	0	0	23	0
2034	0	0	0	0	0	0	0	22	0	0	0	0	0	0	0	0	22	0
2035	0	0	0	0	0	0	0	21	0	0	0	0	0	0	0	0	21	0
2036	0	0	0	0	0	0	0	20	0	0	0	0	0	0	0	0	20	0
2037	0	0	0	0	0	0	0	15	0	0	0	0	0	0	0	0	15	0
2038	0	0	0	0	0	0	0	14	0	0	0	0	0	0	0	0	14	0
2039	0	0	0	0	0	0	0	13	0	0	0	0	0	0	0	0	13	0
2040	0	0	0	0	5	0	0	12	0	0	0	0	0	0	0	0	12	0
2041	0	50	0	0	5	0	0	12	0	0	50	0	0	0	0	0	12	0
2042	0	0	0	0	5	0	10	14	0	0	50	0	0	0	0	0	11	0
2043	0	50	0	0	5	0	0	11	0	0	50	0	0	0	0	0	11	0
2044	0	0	0	0	55	0	0	18	0	0	0	0	0	0	0	0	11	0
2045	0	0	0	0	55	0	0	11	0	0	50	0	0	0	0	0	8	0
Sub Total	-484	1,161	700	1,445	885		20	344	0	-484	1,261	700	1,445	755		10	324	0
Total	**4,071**									**4,011**								
Portfolio Cost ($ x 1,000,000):			**$10,966**							**$11,016**								

*Geothermal Nuclear

Table 11.11 Preferred Portfolio—No SWIP-N comparison table

	Preferred Portfolio (MW)									No SWIP-N (MW)								
Year	Coal Exits	Gas/H2	Wind	Solar	Storage	Trans.	DR	EE	GN*	Coal Exits	Gas/H2	Wind	Solar	Storage	Trans.	DR	EE	GN*
2026	-134	261	0	125	250	0	0	18	0	-134	261	0	125	250	0	0	18	0
2027	0	0	600	420	100	0	0	14	0	0	0	600	420	100	0	0	14	0
2028	0	0	0	100	200	B2H	0	15	0	0	0	0	100	200	B2H	0	15	0
2029	0	150	100	0	155	SWIP-N	10	16	0	0	350	100	0	150	0	0	16	0
2030	-350	650	0	100	0	0	0	16	0	-350	650	0	100	0	0	0	16	0
2031	0	0	0	400	0	0	0	25	0	0	0	0	400	0	0	0	17	0
2032	0	0	0	200	0	0	0	17	0	0	0	0	200	0	0	0	17	0
2033	0	0	0	100	50	0	0	38	0	0	0	0	0	0	0	0	23	0
2034	0	0	0	0	0	0	0	22	0	0	0	0	0	0	0	0	22	0
2035	0	0	0	0	0	0	0	21	0	0	0	0	0	0	0	0	21	0
2036	0	0	0	0	0	0	0	20	0	0	0	0	0	0	0	0	20	0
2037	0	0	0	0	0	0	0	15	0	0	0	0	200	100	0	0	28	0
2038	0	0	0	0	0	0	0	14	0	0	0	0	100	50	0	0	14	0
2039	0	0	0	0	0	0	0	13	0	0	0	0	100	50	0	0	13	0
2040	0	0	0	0	5	0	0	12	0	0	50	0	0	0	0	0	12	0
2041	0	50	0	0	5	0	0	12	0	0	0	0	0	0	0	0	12	0
2042	0	0	0	0	5	0	10	14	0	0	0	0	0	5	0	0	14	0
2043	0	50	0	0	5	0	0	11	0	0	50	0	0	5	0	0	14	0
2044	0	0	0	0	55	0	0	18	0	0	0	0	0	5	0	0	14	0
2045	0	0	0	0	55	0	0	11	0	0	0	0	0	55	0	0	11	0
Sub Total	-484	1,161	700	1,445	885		20	344	0	-484	1,361	700	1,745	970		0	333	0
Total	**4,071**									**4,574**								
Portfolio Cost ($ x 1,000,000):		**$10,966**								**$##,###[29]**								

*Geothermal Nuclear

[29] Confidential circa 2025 IRP filing

Table 11.12 Preferred Portfolio—Load Shift comparison table

	Preferred Portfolio (MW)									Load Shift (MW)								
Year	Coal Exits	Gas/H2	Wind	Solar	Storage	Trans.	DR	EE	GN*	Coal Exits	Gas/H2	Wind	Solar	Storage	Trans.	DR	EE	GN*
2026	-134	261	0	125	250	0	0	18	0	-134	261	0	125	250	0	0	18	0
2027	0	0	600	420	100	0	0	14	0	0	0	600	420	100	0	0	14	0
2028	0	0	0	100	200	B2H	0	15	0	0	0	0	100	200	B2H	0	15	0
2029	0	150	100	0	155	SWIP-N	10	16	0	0	150	100	50	105	SWIP-N	10	16	0
2030	-350	650	0	100	0	0	0	16	0	-350	650	0	100	0	0	0	16	0
2031	0	0	0	400	0	0	0	25	0	0	0	0	400	0	0	0	25	0
2032	0	0	0	200	0	0	0	17	0	0	0	0	200	0	0	0	17	0
2033	0	0	0	100	50	0	0	38	0	0	0	0	150	0	0	0	38	0
2034	0	0	0	0	0	0	0	22	0	0	0	0	0	0	0	0	22	0
2035	0	0	0	0	0	0	0	21	0	0	0	0	0	0	0	0	21	0
2036	0	0	0	0	0	0	0	20	0	0	0	0	0	0	0	0	20	0
2037	0	0	0	0	0	0	0	15	0	0	0	0	0	0	0	0	15	0
2038	0	0	0	0	0	0	0	14	0	0	0	0	0	0	0	0	14	0
2039	0	0	0	0	0	0	0	13	0	0	0	0	0	0	0	0	13	0
2040	0	0	0	0	5	0	0	12	0	0	0	0	0	5	0	0	12	0
2041	0	50	0	0	5	0	0	12	0	0	50	0	0	5	0	0	12	0
2042	0	0	0	0	5	0	10	14	0	0	0	0	0	5	0	10	14	0
2043	0	50	0	0	5	0	0	11	0	0	50	0	0	5	0	0	11	0
2044	0	0	0	0	55	0	0	18	0	0	0	0	0	55	0	0	18	0
2045	0	0	0	0	55	0	0	11	0	0	0	0	0	55	0	0	11	0
Sub Total	-484	1,161	700	1,445	885		20	344	0	-484	1,161	700	1,545	785		20	344	0
Total	**4,071**									**4,071**								
Portfolio Cost ($ x 1,000,000):		**$10,966**								**$10,939**								

*Geothermal Nuclear

Near-Term Action Plan (2026–2030)

The Near-Term Action Plan for the 2025 IRP reflects near-term actionable items of the Preferred Portfolio. The Near-Term Action Plan identifies key milestones to successfully position Idaho Power to provide reliable, economic, and environmentally sound service to customers into the future. The current regional electric market, regulatory environment, pace of technological change, rapid load growth, and Idaho Power's goal of 100% clean energy by 2045 make the 2025 Near-Term Action Plan especially relevant.

The Near-Term Action Plan associated with the Preferred Portfolio is driven by its core resource actions through 2030. These core resource actions include some actions to which the company had committed prior to the development of the 2025 IRP and some that were identified because of the 2025 IRP analysis:

Actions Committed to before the 2025 IRP–Not for Regulatory Acknowledgment

- Conversion of Valmy units 1 and 2 from coal to natural gas by summer 2026 (conversions scheduled to occur by summer of 2026)
- 80 MW of additional cost-effective EE between 2026 and 2030 (added EE identified in Idaho Power's 2024 energy efficiency potential study)
- 125 MW of solar added in 2026 (executed contract for CEYW customer resource)
- 250 MW of four-hour storage added in 2026 (resources selected from the 2026 RFP)
- 600 MW of wind added in 2027 (resources selected from the 2026 RFP)
- 100 MW of solar + storage added in 2027 (resources selected from the 2026 RFP)
- 320 MW of solar added in 2027 (executed contract for CEYW customer resource)
- B2H online by year end 2027
- Issued as 2028 RFP to procure resources to come online in 2028 and beyond (UM 2317)

2025 IRP Decisions for Acknowledgment

- SWIP-N online by November 2028
- Pursue cost-effective existing DR program expansion by 10 MW
- Coordinate with PacifiCorp on the future of Bridger units 3 & 4 given the company's identified need for capacity and energy from Bridger units 3 & 4

- Pursue generation resources in 2029 and 2030 to meet forecasted needs, identified in the preferred portfolio as natural gas, wind, solar, and storage

The Near-Term 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 the Preferred Portfolio is included in this chapter. A chronological listing of the near-term actions follows in Table 11.13.

Table 11.13 Near-Term Action Plan (2026–2030)

Year	Action	Requesting Acknowledgement
Summer 2026	Convert Valmy units 1 and 2 from coal to natural gas	No
2026	125 MW of solar added in 2026 (executed contract for CEYW customer resource)	No
2026	250 MW of four-hour storage added in 2026 (resources selected from the 2026 RFP)	No
2027	600 MW of wind added in 2027 (resources selected from the 2026 RFP)	No
2027	100 MW of solar + storage added in 2027 (resources selected from the 2026 RFP)	No
2027	320 MW of solar added in 2027 (executed contract for CEYW customer resource)	No
2027	B2H online by year end 2027	No
2028	Issue a 2028 RFP to procure resources to come online in 2028 and beyond (UM 2317)	No
2028	SWIP-N online by November 2028	Yes
2026–2028	80 MW of additional cost-effective EE between 2026 and 2030 (added EE identified in Idaho Power's 2024 energy efficiency potential study)	No
2029	Pursue cost-effective existing DR program expansion by 10 MW	Yes
2026–2030	Coordinate with PacifiCorp on the future of Bridger units 3 & 4 given the company's identified need for capacity and energy from Bridger units 3 & 4	Yes
2029–2030	Pursue generation resources in 2029 and 2030 to meet forecasted needs, identified in the preferred portfolio as natural gas, wind, solar, and storage	Yes

Resource Procurement

Idaho Power's capacity shortfall identified for 2028 through 2030 will require incremental generating capacity. Idaho Power issued an all-source 2028 RFP in 2024. This RFP is for resources to come online by summer 2028 and beyond. The 2028 final short list for the all source 2028 RFP was acknowledged in April 2025 by the OPUC. Contracting for 2028 resources from the all-source 2028 RFP is ongoing. The analysis for 2029 and beyond bids for the 2028 all-source RFP is ongoing. For more information on Idaho Power RFPs visit idahopower.com/about-us/doing-business-with-us/request-for-resources/.

Annual Capacity Positions

To align with and represent the probabilistic reliability analyses utilized in the 2025 IRP, the company provides below the annual capacity positions before and after the incorporation of the Preferred Portfolio resource buildout (Table 11.15). The pre-Preferred Portfolio annual capacity positions represent the company's resource and load inputs at the time of the 2025 IRP analysis, with the following notable base changes:

- No PURPA replacement contracts and no PURPA forecast
- No 2027 and 2028 resource adjustments
- Exit Bridger units 3 and 4 in 2030
- No WRAP capacity benefit

The resulting capacity deficiency of approximately 54 MW in 2027, and the generally growing deficit, clearly demonstrates the company's on-going capacity needs.

Table 11.14 Pre and post Preferred Portfolio annual capacity positions

Annual Capacity Position (MW)				
Year	Existing & Contracted Resource Only		Add Preferred Portfolio Resources	
2026	61	Length	66	Length
2027	(54)	Shortfall	47	Length
2028	(105)	Shortfall	22	Length
2029	(297)	Shortfall	66	Length
2030	(677)	Shortfall	222	Length
2031	(656)	Shortfall	302	Length
2032	(790)	Shortfall	187	Length
2033	(874)	Shortfall	151	Length
2034	(858)	Shortfall	161	Length
2035	(762)	Shortfall	232	Length
2036	(797)	Shortfall	212	Length
2037	(910)	Shortfall	173	Length
2038	(947)	Shortfall	131	Length
2039	(977)	Shortfall	94	Length
2040	(1,011)	Shortfall	68	Length
2041	(1,047)	Shortfall	78	Length
2042	(1,077)	Shortfall	55	Length
2043	(1,146)	Shortfall	60	Length
2044	(1,171)	Shortfall	64	Length
2045	(1,265)	Shortfall	64	Length

The first month of deficiency was determined to be the first month that exceeded a 0.0083 event-days per year LOLE (or 0.1 divided by 12) on the first year of capacity deficiency (2027). For this IRP, the first month over that threshold was June 2027, as shown in Figure 11.1.

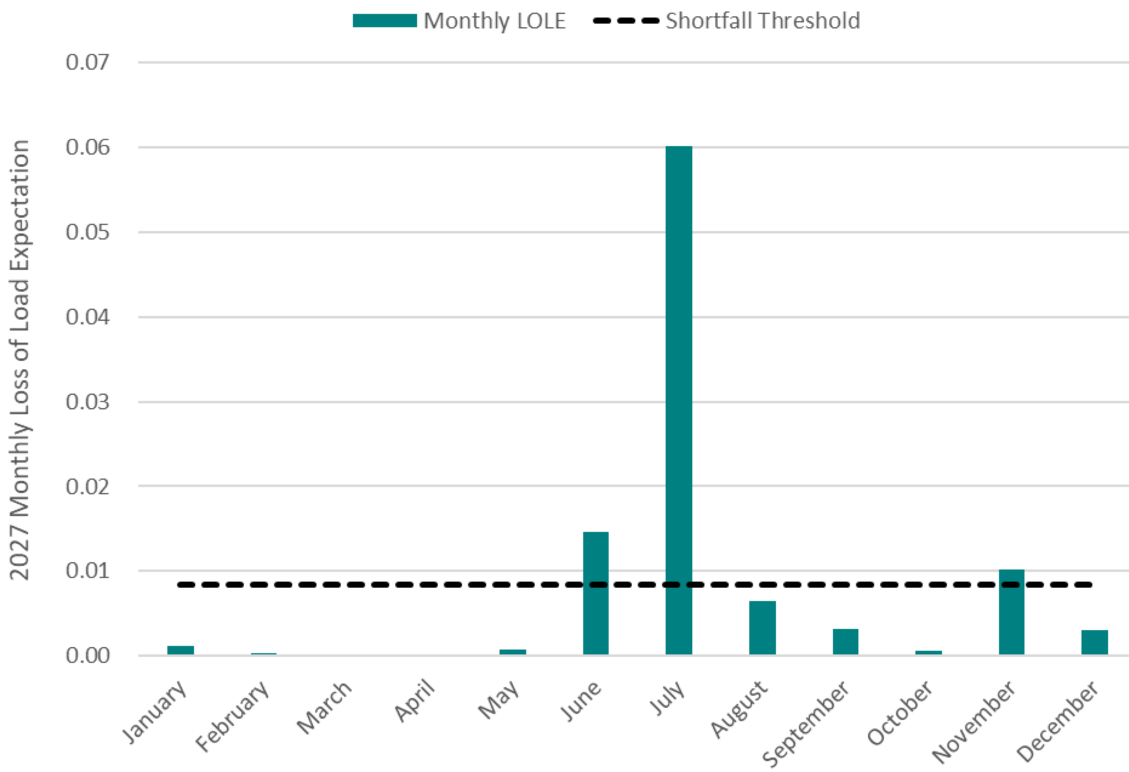


Figure 11.1 First month of capacity shortfall

More information on the LOLE-derived capacity position calculation can be found in the System Reliability Modeling—Portfolio Analysis section of *Appendix D—System Reliability and Regulating Reserves*.

2027 IRP Filing Schedule

The 2027 IRP will be filed in June 2027. The following associated tasks will be completed between the 2025 IRP filing and the 2027 IRP filing:

- Model inputs will be collected and reviewed with IRPAC.
- Between 8 and 12 IRPAC meetings will be conducted in 8–12 months.
- The analysis will begin coincident with the last three to four IRPAC meetings.
- The report will be drafted concurrent with the IRPAC meetings and analysis.
- A public review will be scheduled prior to the IRP filing.
- The IRP will be filed in June 2027.

Conclusion

The 2025 IRP provides guidance for Idaho Power as its portfolio of resources evolves over the coming years. As the plan shows, Idaho Power is expected to go through a period of unprecedented demand growth in the next several years. This demand growth is predominantly from customers whose load is flat both seasonally and diurnally. The analysis and testing in this IRP shows the clear need for firm flexible resources like new natural gas, the buildout of interregional transmission like B2H and SWIP-N, and continued investment in renewable and storage resources consistent with recent procurement activities. The Preferred Portfolio is a roadmap showing how Idaho Power will continue its long history of providing affordable and reliable energy to customers in southern Idaho and eastern Oregon.

Idaho Power linemen install upgrades.

Idaho Power prepares an IRP every two years. The next plan will be filed in 2027. The energy industry is expected to continue undergoing substantial transformation over the coming years, and new challenges and questions will be encountered and analyzed in the 2027 IRP.