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February 16, 2022

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Filing Center
P.O. Box 1088
201 High Street S.E., Suite 100
Salem, OR 97308-1088

Re: Docket LC 78 - Idaho Power Company's 2021 Integrated Resource Plan Appendix D and Errata

Attention Filing Center:

Attached for electronic filing is Appendix D to Idaho Power Company's (Idaho Power or Company) 2021 Integrated Resource Plan (IRP), which the Company had stated would be filed in the first quarter of 2022. Additionally, the Company submits for electronic filing eight (8) replacement pages with corrected portfolio cost information. As explained and demonstrated below, these portfolio cost updates are immaterial in nature, do not impact the selection of the Preferred Portfolio, and do not adjust any of the portfolio rankings in the 2021 IRP.

Appendix D

Appendix D of Idaho Power's 2021 IRP includes updates on the Boardman to Hemingway (B2H) project, including explanation of the finalized term sheet signed by Idaho Power, PacifiCorp, and Bonneville Power Administration. Idaho Power previously filed the term sheet in this docket on January 19, 2022.

In addition to updates and analysis related to the B2H project, Appendix D provides information on Idaho Power's transmission system, how it is modeled in the IRP, and the modeling and status of other potential transmission projects, such as Gateway West.

Replacement Pages

In addition to Appendix D, Idaho Power is filing eight (8) replacement pages to the main 2021 IRP report. In the process of organizing IRP data files during completion of Appendix D, Idaho Power identified two separate data discrepancies related to Bridger Plant cost estimates. These updates result in immaterial cost changes to portfolios in the 2021 IRP.

The first data issue arose because of the timing of revised estimates received by the Company for costs related to the early exit of the Bridger Plant units. Idaho Power continued to receive updated cost estimates throughout December 2021. To determine portfolio costs in the IRP, Idaho Power inadvertently used the penultimate set of cost estimates rather than the final cost estimates. For portfolios in which any of the Bridger units are exited before end of book life, the revised costs increase the net present value (NPV) of portfolios by between $4 and $6 million—an increase of between 0.041 percent to 0.077 percent. This portfolio cost increase is de minimis in relation to total portfolio costs of approximately $8 billion, and does not change the selection of the Preferred Portfolio, nor does it change any of the portfolio rankings or sensitivity outcomes.

The second data issue, related to cost estimates for the Bridger Plant natural gas conversion, was due to the inadvertent exclusion of fixed operations and maintenance (O&M) costs associated with the conversion in IRP portfolio cost development. The IRP planning team believed these costs were accounted for in Idaho Power's internal finance (p-worth) model. However, due to the newness of Bridger Plant conversion discussions, this cost stream had not yet been incorporated into the p-worth. These fixed O&M costs add between approximately $12-23 million to total NPV portfolio costs in the IRP—a cost increase of between 0.2 percent to 0.3 percent to portfolios and sensitivities in which either unit 1 or 2 is converted to natural gas. Similar to the issue above, this increase is immaterial to the IRP analysis, does not change the selection of the Preferred Portfolio, and has no impact on portfolio rankings or sensitivity outcomes.

Combined, these corrected data issues result in NPV portfolio cost increases of between $5 million and $29 million on total NPV portfolio costs of approximately $8 billion—an increase of *less than half of 1 percent* on affected portfolios. The table below compares the NPV of a selection of portfolio costs as originally published compared to the amended amounts included in the replacement pages. As the table demonstrates, the portfolio cost increases resulting from these two issues do not change any aspect of Preferred Portfolio selection or portfolio rankings.

2021 IRP portfolios, NPV years 2021–2040 ($ x 1,000)

Portfolio	ORIGINAL Planning Gas, Planning Carbon	UPDATED Planning Gas, Planning Carbon	Total Percentage Increase
Base with B2H	$7,915,702	$7,942,428	0.34%
Base B2H PAC Bridger Alignment	$7,999,347	$8,021,906	0.28%
Base without B2H	$8,192,830	$8,219,281	0.32%
Base without B2H without Gateway West	$8,441,414	$8,470,101	0.34%
Base without B2H PAC Bridger Alignment	$8,185,334	$8,207,893	0.28%
Base with B2H—High Gas High Carbon Test	$7,997,339	$8,024,064	0.33%

Idaho Power is committed to identifying and correcting issues in a straightforward and transparent manner. To this end, the Company provides this update to ensure the Commission and stakeholders are operating with the latest and most accurate information. Idaho Power believes its thorough quality control process brought to light these minor issues and allowed for a timely correction.

Please contact this office with any questions.

Respectfully submitted,

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2021 IRP
INTEGRATED RESOURCE PLAN

A VIEW
FROM ABOVE

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SAFE HARBOR STATEMENT

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EXECUTIVE SUMMARY

Idaho Power Company (Idaho Power or the company) developed *Appendix D–Transmission Supplement* to detail many of the transmission cost and modeling assumptions utilized in the 2021 Integrated Resource Plan (IRP), as well as discuss other details related to transmission. The primary focus of *Appendix D* will continue to be the Boardman to Hemingway Transmission Line (B2H) project.

2021 IRP B2H Project Update

The B2H project is moving into the preliminary construction phase of the project. On January 18, 2022, after significant discussions, study efforts, and negotiations, the three B2H permit funding parties, Idaho Power, PacifiCorp (PAC), and Bonneville Power Administration (BPA), executed a Non-Binding Term Sheet that addresses B2H ownership, transmission service considerations, and asset exchanges. The parties entered into this Term Sheet after 1) jointly funding the permitting of the B2H project over the past decade, and 2) over two years of discussions related to next steps associated with the B2H project. Since signing the B2H Permit Funding Agreement in 2012, a decade has passed, and the parties' capacity needs, strategies, and goals associated with the project have shifted. The three parties negotiated the Term Sheet as the framework for future agreements required between and among the parties.

As part of the Term Sheet, BPA will transition out of its role as a joint B2H permitting partner and will instead take transmission service from Idaho Power to serve its southeast Idaho customers. Idaho Power will increase its B2H ownership to 45.45% by acquiring BPA's planned share of B2H capacity. Idaho Power's B2H capacity will increase from an average of 350 megawatts (MW) west-to-east to 750 MW west-to-east, and Idaho Power will utilize a portion of its increased B2H capacity to provide BPA transmission service across southern Idaho.

As part of the larger transaction, Idaho Power and PAC plan to complete an asset exchange to align transmission ownership with each party's long-term strategy. Idaho Power will acquire PAC transmission assets and their related capacity sufficient to enable Idaho Power to utilize 200 MW of bidirectional transmission capacity between the Idaho Power system (Populus) and Four Corners substation in New Mexico. Idaho Power will also acquire PAC assets around the Goshen area necessary to provide transmission service to BPA to serve its southeast Idaho customers. PAC will acquire Idaho Power transmission assets and their related capacity sufficient to enable PAC to utilize 600 MW of east-to-west and 300 MW of west-to-east transmission capacity across southern Idaho.

In the 2021 IRP, Idaho Power estimates that its 45.45% share of B2H costs will be approximately $500 million (with no contingency) and evaluated a high-end cost of $600 million with a 30%

cost contingency for future expenses. The B2H cost estimate included Idaho Power's costs for local interconnection upgrades totaling approximately $35 million and additional system upgrades totaling approximately $47 million.

B2H Background and Purpose

B2H is a planned 500 kilovolt (kV) transmission project that will span between the Hemingway 500 kV substation near Melba, Idaho, and the proposed Longhorn Station near Boardman, Oregon. Once operational, B2H will provide Idaho Power increased access to reliable, low-cost market energy purchases from the Pacific Northwest year-round, including when energy demand from Idaho Power's customers is at its highest. B2H has been a cost-effective resource identified in each of Idaho Power's IRPs since 2009 and continues to be a cornerstone of Idaho Power's 2021 IRP Preferred Portfolio. In the 2021 IRP, as has been the case in prior IRPs, the B2H project is not simply evaluated as a transmission line, but rather as a *resource* that will be used to serve Idaho Power load. That is, the B2H project, and the market purchases it will facilitate, is evaluated in the same manner as a new gas plant, or a new utility-scale solar plus storage project.

As a resource, the B2H project is demonstrated to be the most cost-effective method of serving projected customer demand. As can be seen in the 2021 IRP, the lowest-cost resource portfolio includes B2H, and the best non-B2H portfolio has a significant cost premium. As a resource alone, B2H is the lowest-cost alternative to serve Idaho Power's customers in Oregon and Idaho. As a transmission line, B2H also offers incremental ancillary benefits and additional operational flexibility.

In addition to being the least-cost resource to meet Idaho Power's resource needs, the B2H project received national recognition for the benefits it will provide. The B2H project was selected by the Obama administration as one of seven nationally significant transmission projects that, when built, will help increase electric reliability, integrate new renewable energy into the grid, create jobs, and save consumers money. B2H was also acknowledged as complementing the Trump Administration's America First Energy Plan, which addresses all forms of domestic energy production. In a November 17, 2017, United States Department of the Interior press release,[1] B2H was held up as a "priority focusing on infrastructure needs that support America's energy independence." The release went on to say, "This project will help stabilize the power grid in the Northwest, while creating jobs and carrying low-cost energy to the families and businesses who need it." Finally, B2H was identified by Americans for a Clean Energy Grid as one of 22 high-voltage transmission projects that "could interconnect around 60,000 MW of new renewable capacity, increasing America's wind and solar generation by

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

nearly 50% from current levels.[2]" The benefits B2H is expected to bring to the region and nation have been recognized across both major political parties.[3]

Idaho Power is the project manager for the permitting phase of the B2H project. The B2H project achieved a major milestone nearly ten years in the making with the release of the Bureau of Land Management (BLM) Record of Decision (ROD) on November 17, 2017, approving a right-of-way for the B2H project on BLM-administered land. Idaho Power also received a ROD for B2H from the United States Forest Service in 2018 and from the United States Navy in 2019. In 2021, the RODs issued by the BLM and the Forest Service were upheld by the United States District Court for the District Court of Oregon. No parties appealed that ruling.

For the State of Oregon permitting process, Idaho Power submitted the amended application for Site Certificate to the Oregon Department of Energy (ODOE) in the summer of 2017. ODOE issued a Proposed Order on July 2, 2020, that recommends approval of the project to Oregon's Energy Facility Siting Council (EFSC). Currently, EFSC is conducting a contested case proceeding on the Proposed Order. EFSC is tasked with establishing siting standards for energy facilities in Oregon and ensuring certain transmission line projects, including B2H, meet those standards.[4] Before Idaho Power can begin construction on B2H, it must obtain a Site Certificate from EFSC. The Oregon EFSC process is a standards-based process based on a fixed site boundary. For a linear facility, like a transmission line, the process requires the transmission line boundary be established (a route selected) and fully evaluated to determine if the project meets established standards. Idaho Power must demonstrate a need for the project before EFSC will issue a Site Certificate authorizing the construction of a transmission line (non-generating facility). Idaho Power's demonstration of need is based in part on the least-cost plan rule, for which the requirements can be met through a commission acknowledgement of the resource in the company's IRP.[5] The Oregon Public Utility Commission (OPUC) has already acknowledged the construction of B2H in Idaho Power's 2017 IRP and 2019 IRP. In this case, Idaho Power again seeks to confirm its acknowledgement of B2H as reflected in the 2021 IRP.

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[2] See https://cleanenergygrid.org/wp-content/uploads/2021/09/Transmission-Projects-Ready-to-Go.pdf.

[3] The importance of high-voltage transmission to a decarbonized future continues to receive attention from experts and scholars alike. In 2021, Princeton University published the Net-zero America Report, which asserts that the United States will need to expand its high voltage transmission system by 60% by 2030, and may need to triple it by 2050 to meet net zero futures. https://www.dropbox.com/s/ptp92f65lgds5n2/Princeton%20NZA%20FINAL%20REPORT%20(29Oct2021).pdf?dl=0

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

[5] OAR 345-023-0020(2). Idaho Power is also requesting satisfaction of the need standard under EFSC's System Reliability Rule, OAR 345-023-0030.

As of the date of this report, Idaho Power expects ODOE to issue its decision on the Site Certificate in 2022. To achieve a 2026 in-service date, as shown in the near-term Action Plan, preliminary construction activities have commenced in parallel to EFSC permitting activities. Preliminary construction activities include, but are not limited to: geotechnical explorations, detailed ground surveys, sectional surveys, right-of-way (ROW) option acquisition activities, detailed design, and construction bid package development. After the Oregon permitting process and preliminary construction activities conclude, construction activities can commence.

Gateway West Considerations in the 2021 IRP

In the 2021 IRP, Idaho Power performed extensive evaluations on the Gateway West project. The project was ultimately not included as part of the 2021 IRP Preferred Portfolio; however, many portfolios, including most portfolios that did not include B2H, identified at least one phase of Gateway West as being necessary to facilitate the large renewable buildouts required. Idaho Power expects that resource development in southern Idaho by the company, or other third-party's, and geographically diverse resource adequacy needs will drive the need for Gateway West in the coming years. The company will continue to evaluate Gateway West in future IRPs.

Existing Transmission Utilized for Firm Imports

As detailed in the 2021 IRP Report Chapter 11–Transmission Market Shifts and Constraints, Idaho Power has reduced the *existing* transmission assumed available for market purchases within the Load and Resource Balance from approximately 900 MW in the 2019 IRP to approximately 710 MW in the 2021 IRP during the peak-load month of July.

The company decreased this availability due to transmission constraints and the company's decreasing ability to access markets. Since the August 2020 energy emergency event in California, the Idaho Power transmission service queue has been flooded with multi-year requests totaling more than 1,000 MW as of April 2021, looking to move energy from the Mid-Columbia market (Mid-C) across Idaho Power's transmission system to the south.

While the company is able to reserve its own transmission for use by its customers, the transmission service requests just outside of Idaho Power's service area have placed additional pressure on an already constrained market, limiting the company's access to capacity at Mid-C. The company also began to secure long-term rights across other transmission providers, and by summer 2023, the company will have added 380 MW of long-term firm transmission rights across third-party systems to the company's border. The company sought to purchase more additional firm transmission capacity, but it was not available. These 380 MW, in addition to the company's 330 MW emergency transmission capacity (capacity benefit margin), account for the 710 MW available for July market purchases across existing transmission in the 2021 IRP.

More information about existing transmission availability assumptions can be found in the Transmission Capacity Between Idaho Power and the Pacific Northwest section of this appendix.

2022 TERM SHEET AND B2H PROJECT PARTNER UPDATE

The 2022 B2H Term Sheet and the 2021 IRP

The B2H Term Sheet items reflected below were all factored into the development and execution of Idaho Power's 2021 IRP.

B2H Related Terms

The B2H project is moving into the preliminary construction phase. On January 18, 2022, and after significant discussions, study efforts, and negotiations, the three B2H permit funding parties, Idaho Power, PAC, and BPA, executed a Non-Binding Term Sheet that addresses B2H ownership, transmission service considerations, and asset exchanges. The parties entered into this Term Sheet after 1) jointly permitting the B2H project over the past decade, and 2) over two years of discussions related to next steps associated with the B2H project. A decade has passed since signing of the B2H Transmission Project Joint Permit Funding Agreement in 2012, and the parties' capacity needs, strategies, and goals associated with the project have shifted. The three parties negotiated the Term Sheet as the framework for future agreements required between and among the parties.

Per the Term Sheet, BPA will transition out of its role as a joint B2H permit funding coparticipant and will instead rely on B2H by taking transmission service from Idaho Power to serve its customers. To accommodate this change, Idaho Power will increase its B2H ownership share to 45.45% by acquiring BPA's B2H capacity. Idaho Power's B2H capacity will increase from an average of 350 MW west-to-east to 750 MW west-to-east and Idaho Power will utilize a portion of its increased B2H capacity to provide BPA network transmission service across southern Idaho.

PAC's B2H interest is not impacted by BPA transitioning out of the project and their B2H capacity will remain at 300 MW west-to-east and 600 MW east-to-west.

There remains 400 MW of unallocated B2H east-to-west capacity.

Idaho Power and BPA Terms

B2H Development Risk: The Term Sheet reflects BPA's intent to transition out of its role as a joint B2H permitting partner and to rely on the completed B2H project to take transmission service from Idaho Power to serve its customers in southeast Idaho. The Term Sheet adjusts the funding and ownership percentages as follows:

- In addition to its current 21% ownership, Idaho Power will assume BPA's 24% ownership share in B2H; and Idaho Power will provide transmission service across southern Idaho to BPA's customers through Network Integration Transmission Service Agreements

(NITSA) under Idaho Power's Open Access Transmission Tariff. These NITSAs will remain in effect for a minimum 20-year period.

- In concert with the NITSAs, Idaho Power will acquire BPA's B2H permitting interest and, on a going-forward basis, will fund 45% of B2H project development costs for permitting and pre-construction. In the event Idaho Power is unable to secure B2H permits or state Certificates of Public Convenience and Necessity, BPA will compensate Idaho Power for 24% (based on BPA's funding obligations before the transfer of BPA's permitting interest to Idaho Power) of the permitting and preconstruction costs incurred after BPA's interest transfers to Idaho Power.

Permitting Cost Reimbursement: In concert with the NITSAs, starting ten years after B2H is placed in service, Idaho Power will reimburse BPA for the value of the permitting costs paid by BPA. Interest will accumulate on the permitting balance starting on the B2H in-service date.

BPA Wheeling Revenue will Offset BPA Related Costs: BPA's transmission service payments to Idaho Power under the NITSAs will offset Idaho Power's costs associated with BPA's usage of the B2H project over time, and, therefore, Idaho Power's customers will not be harmed by the changes to the arrangement.

Idaho Power Wheeling Across BPA Transmission: In a related transaction, Idaho Power will secure 500 MW of point-to-point transmission service (PTP) from BPA from the Mid-Columbia market (Mid-C) to the proposed Longhorn Station, which will provide Idaho Power a direct connection to the Mid-C market with flexible long-term BPA wheeling rights.

Longhorn Station Terms

The B2H project will interconnect with the proposed BPA Longhorn Station near Boardman, Oregon, which BPA will own and operate. BPA is in the process of evaluating the construction of the proposed Longhorn Station to satisfy an interconnection request of a BPA customer and anticipates making a decision regarding its construction later in 2022.

Funding the Longhorn Station: Under the Term Sheet, BPA will fund Idaho Power's share, about $14 million, of the interconnection costs to the proposed Longhorn Station.

Funding of the B2H Connection to Longhorn: Idaho Power and PAC will fund assets and associated costs, to be reimbursed by BPA, that are required to directly connect B2H to the Longhorn Station. BPA will satisfy its reimbursement obligations to Idaho Power via transmission service credits associated with Idaho Power's 500 MW of PTP service across BPA from Mid-C to Longhorn Station.

Funding the B2H Series Capacitor at Longhorn: Idaho Power and PAC will fund and own the B2H series capacitor and associated equipment at Longhorn Station. Idaho Power and/or PAC will have access to the Longhorn Station to perform maintenance and inspections on jointly owned equipment in the Longhorn Station.

Idaho Power and PAC Terms

In addition to the transactions directly related to construction and operation of B2H, Idaho Power and PAC have agreed to exchange certain assets and take other actions as follows upon completion of B2H, conditioned on reaching definitive agreements:

Idaho Power Assets to be Acquired from PAC: Idaho Power will acquire PAC transmission assets and their related capacity sufficient to enable Idaho Power to utilize 200 MW of bidirectional transmission capacity between the Idaho Power system (Populus Substation in Idaho) and Four Corners Substation in New Mexico. Idaho Power will also acquire PAC assets around the Goshen, Idaho, area necessary to provide transmission service to BPA to serve their southeast Idaho customers.

PAC Assets to be Acquired from Idaho Power: PAC will acquire Idaho Power transmission assets and their related capacity sufficient to enable PAC to utilize 600 MW of east-to-west and 300 MW of west-to-east transmission capacity across southern Idaho.

PAC Point-to-Point Contracts: PAC will terminate its existing 510 MW of east-to-west transmission service across southern Idaho Power and acquire 300 MW of west-to-east conditional firm service. To achieve the 300 MW of west-to-east service, PAC will obtain (through reassignment) BPA's 200 MW of PTP west-to-east conditional firm service across southern Idaho. PAC has procured 100 MW of incremental west-to-east conditional firm service from Idaho Power across southern Idaho.

Additional Upgrades Required: Transmission capacity on the Idaho Power operated Borah West and Midpoint West transmission paths must be upgraded to support additional east-to-west schedules required by Idaho Power and PAC across southern Idaho. There are two system upgrade projects identified to reinforce Borah West and Midpoint West to enable these increased east-to-west transmission flows through Idaho:

1. Midpoint-Kinport 345 kV Series Capacitor Addition: The addition of a series capacitor on the existing Midpoint–Kinport 345 kV line will increase the Borah West path rating by approximately 500 MW. This series capacitor allows for more optimal distribution of flows on the existing 345 kV lines west of Borah Station near American Falls, Idaho.

2. Midpoint 500/345 kV Second Transformer Addition: The existing single 500/345 kV transformer bank is a bottleneck for increased flows across the Idaho system. A second 500/345 kV transformer will need to be installed to increase the capacity of the existing

Midpoint–Hemingway 500 kV line to accommodate higher east-to-west transfers across southern Idaho.

In the 2021 IRP, Idaho Power conservatively assumed that the full cost (about $47 million) of these upgrades will be funded by the company. The actual cost responsibility will be determined as Idaho Power and PAC perform detailed analysis associated with the asset exchange.

B2H Revised Scope–Midline Series Capacitor

Idaho Power and PAC will construct a B2H midline series capacitor substation around the mid-point of the B2H transmission line. This midline series capacitor—identified through joint planning studies by Idaho Power, PAC, and BPA—is required to address interactions between B2H and other existing transmission paths and to meet the three parties' needs. This midline substation was not included in the original project scope and will require additional permitting. It is anticipated that this additional permitting will not delay the B2H in-service date.

IDAHO POWER'S TRANSMISSION SYSTEM

Idaho Power's transmission system is a critical component of Idaho Power's system enabling Idaho Power to provide reliable and fair-priced energy services. A map of Idaho Power's transmission system is shown in Figure 7.1 of the 2021 IRP and in Figure 1 of this appendix. Transmission lines facilitate the delivery of economic resources and allow resources to be sited where most cost effective. In most instances, the most economic/best location for resources is not immediately next to major load centers (i.e., hydro along the Snake River, wind in Wyoming, solar in the Desert Southwest). For much of its history, Idaho Power has relied upon resources outside of its major load pockets to economically serve its customers. The existing transmission lines between Idaho Power and the Pacific Northwest have been particularly valuable. Idaho Power fully utilizes the capacity of these lines. Additional transmission capacity is required to access resources to serve incremental increases in peak demand. The B2H project is the mechanism to increase capacity between the Pacific Northwest and Idaho Power's service area.

Transmission lines are constructed and operated at different operating voltages depending on purpose, location and distance. Idaho Power operates transmission lines at 138 kV, 161 kV, 230 kV, 345 kV, and 500 kV. Idaho Power also operates sub-transmission lines at 46 kV and 69 kV. The higher the voltage, the greater the capacity of the line, but also greater construction cost and physical size requirements.

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

Transmission Market Shifts and Constraints

As discussed in the Transmission Market Shifts and Constraints section of Chapter 11 of the 2021 IRP, starting on page 168, the company made significant adjustments to its transmission availability assumptions.

As a result of recent and significant market changes, for the years 2023 through 2025, Idaho Power has reduced the transmission availability within the Load and Resource Balance from approximately 900 MW in the 2019 IRP to approximately 710 MW in the 2021 IRP during the peak-load month of July. The following sections detail the makeup of this 710 MW.

Idaho Power's Existing Transmission Capacity

A transmission path is one or more transmission lines that collectively transmit power to and from one geographic area to another.

Idaho to Northwest Path Description

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

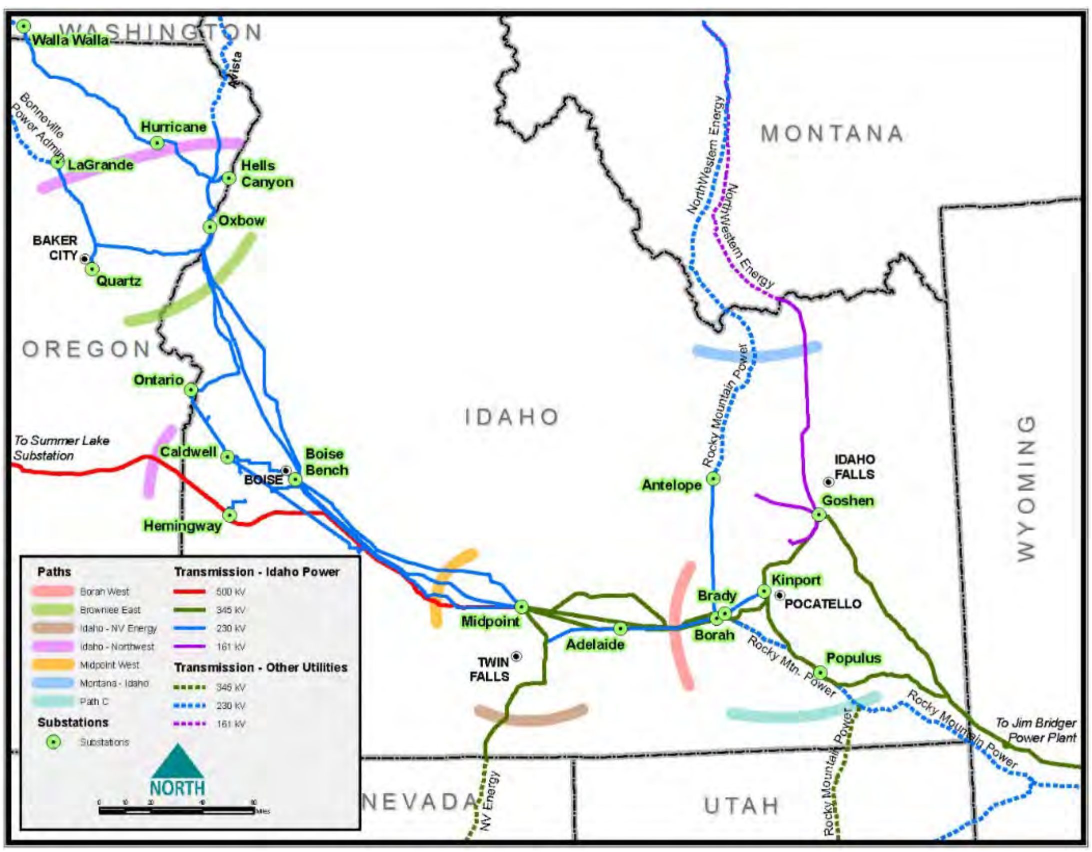

Figure 1. Idaho Power transmission system map

Table 1 details the capacity allocation between the Pacific Northwest and Idaho Power in 2021. The shaded rows represent capacity amounts that can be used to serve Idaho Power's native load customers, although Capacity Benefit Margin (CBM) can only be accessed as firm capacity if Idaho Power is in an energy emergency.

Table 1. Pacific Northwest to Idaho Power west-to-east transmission capacity

Firm Transmission Usage (Pacific Northwest to Idaho Power)	Capacity (July MW)
BPA Load Service (Network Customer)	332
Fighting Creek (PURPA)	4
Transmission Reliability Margin (TRM)	281
Capacity Benefit Margin (CBM)	330
Subtotal	**947**
Pacific Northwest Purchase (Idaho Power Load Service)	333
Total	**1,280**

Montana–Idaho Path Utilization

Idaho Power's share of the Montana–Idaho path includes 80 MW of capacity on a 230 kV line interconnecting with BPA or Avista and a 161 kV line interconnecting with Northwestern Energy. The 161 kV line is not included in the total Pacific Northwest to Idaho Power import capacity due to commercial constraints beyond the Idaho Power border. To utilize the 80 MW capacity connection, Idaho Power must purchase transmission service from either Avista or BPA. This transmission system connects the purchased resource in the Pacific Northwest to Idaho Power's transmission system. Avista or BPA transmits, or wheels, the power across their transmission system and delivers the power to Idaho Power's transmission system. The Montana–Idaho path is identified in Figure 1 above.

Idaho to Northwest Path Utilization

To use Idaho Power's share of the Idaho to Northwest capacity, Idaho Power must purchase transmission service from Avista, BPA, or PAC. Table 2 details a typical summer allocation of the Idaho to Northwest capacity:

Table 2. The Idaho to Northwest Path (WECC Path 14) summer allocation

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

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

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

Construction of B2H will add 1,050 MW of capacity to the Idaho to Northwest path in the west-to-east direction, of which Idaho Power will own 750 MW and plans to utilize 500 MW the summer months (April–September) and 200 MW in the winter months (January–March and October–December) for Idaho Power customer service. The remainder of the Idaho Power capacity will mainly be used for incremental network transmission service to BPA southeast Idaho customers. A total breakdown of capacity rights of the B2H permitting coparticipants can be found in the B2H Capacity Interest section of this report. The Idaho to Northwest path is identified in Figure 1 above.

Transmission Capacity to the South

Referencing Figure 1, the company owns or controls transmission capacity between utilities in the south, and Idaho Power via the Idaho–NV Energy path (aka Idaho–Sierra path or WECC Path 16) and Path C (WECC Path 20).

Idaho Power utilizes the Idaho–NV Energy path to import Valmy energy, and the path rating is 360 MW in the south-to-north direction. There is no firm transmission availability across Nevada to leverage this 360 MW of import capacity to access Desert Southwest markets.

PAC is the owner and operator of the Path C transmission lines. Idaho Power has secured 50 MW of transmission capacity between the months of June and October to access the Desert Southwest markets. This 50 MW makes up a part of the 2021 IRP's approximately 710 MW of transmission capacity detailed in the Load and Resource Balance.

Transmission in the 2021 IRP Load and Resource Balance

Due to the market shifts referenced in the Transmission Market Shifts and Constraints section, transmission capacity has been constrained. Table 3 details the amount of Mid-C to Idaho Power and Desert Southwest to Idaho Power capacity to which the company will have rights by 2023.

Table 3. Third-party secured import transmission capacity

Third-Party Provider	Market	Capacity (MW)
Avista via Lolo	Pacific Northwest	200
PAC via Walla Walla	Pacific Northwest	80
BPA via La Grande	Pacific Northwest	50
PAC via Red Butte (Utah/Nevada border)	Desert Southwest	50
Subtotal		**380**
Emergency Transmission (CBM)	Pacific Northwest	330
Total		**710**

The B2H project will add 750 MW of Idaho Power owned transmission capacity between BPA and Idaho Power. Additionally, Idaho Power plans to secure 500 MW of point-to-point transmission service across BPA's transmission system to connect B2H to the Mid-C market hub. As part of the Term Sheet, Idaho Power will also acquire from PAC 200 MW of south-to-north transmission ownership from the Desert Southwest market hub (Four Corners) to the Idaho Power system. However, Idaho Power did not specifically allocate any incremental summer capacity associated with the Four Corners capacity into the Load and Resource Balance.

More Details Related to CBM: CBM is transmission capacity Idaho Power sets aside on the company's transmission system, as unavailable for firm use, for the purposes of accessing reserve energy to recover from severe conditions such as unplanned generation outages or energy emergencies. Reserve generation capacity is critical and CBM allows a utility to reduce the amount of reserve generation capacity on its system by providing transmission availability to another market, in this case the Pacific Northwest. An energy emergency must be declared by Idaho Power before the CBM transmission capacity becomes firm. To access the market, transmission beyond Idaho Power on third party providers must be acquired. The company anticipates this third-party transmission will be available during an energy emergency event. Idaho Power includes the 330 MW of emergency transmission (CBM) toward meeting a 15.5% planning margin. In future IRP's, Idaho Power will continue to evaluate how CBM applies in the context of Idaho Power's Load and Resource Balance, specifically if the company is a member of a regional resource adequacy program.

More Details Related to TRM: TRM is transmission capacity that Idaho Power sets aside as unavailable for firm use, for the purposes of grid reliability to ensure a safe and reliable transmission system. Idaho Power's TRM methodology, approved by the Federal Energy Regulatory Commission (FERC) in 2002, requires Idaho Power to set aside transmission capacity based on the average loop flow on the Idaho to Northwest path. In the west, electrical power is scheduled through a contract-path methodology, which means if 100 MW is purchased and scheduled over a path, that 100 MW is decremented from the path's total availability. However, physics dictates the actual power flow over the path (based on the path of least resistance), so actual flows don't equal contract-path schedules. The difference between scheduled and actual flow is referred to as unscheduled flow or loop flow. The average adverse loop flow across the Idaho to Northwest path during the month of July is 281 MW.

Regional Planning—Studies and Conclusions

Idaho Power is active in NorthernGrid, a regional transmission planning association of 13 member utilities. The NorthernGrid was formed in early 2020. Previously, dating back to 2007, Idaho Power was a member of the Northern Tier Transmission Group. NorthernGrid operates in compliance with FERC Orders 890 and 1000.

NorthernGrid membership includes Avista, Berkshire Hathaway Energy Canada, BPA, Chelan County Public Utility District (PUD), Grant County PUD, Idaho Power, NorthWestern Energy, NV Energy, PAC (Rocky Mountain Power and Pacific Power), Portland General Electric, Puget Sound Energy, Seattle City Light, Snohomish County PUD, and Tacoma Power. Biennially, NorthernGrid will develop a regional transmission plan using a public stakeholder process to evaluate transmission needs resulting members' load forecasts; local transmission plans; IRPs; generation interconnection queues; other proposed resource development and forecast uses of the transmission system by wholesale transmission customers. The 2020–2021 regional transmission plan was published in December 2021 and can be found in the NorthernGrid website: northerngrid.net.

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 is similarly a major component of the 2020–2021 NorthernGrid regional transmission plan, published in December 2021[6]. Regional transmission planning efforts are widely regarded as producing efficient and cost-effective pathways to meet the load and resource needs of a region.

[6] See https://www.northerngrid.net/private-media/documents/2020-2021_Regional_Transmission_Plan.pdf

B2H DEVELOPMENT

For details related to B2H project history, public participation, project activities, route history, and a detailed list of notable project milestones, please reference Appendix D-2 at the end of this Appendix.

B2H Design

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

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

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

Transmission Line Design

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

The basic purpose of a transmission line is to move power from one substation to another for eventual distribution of electricity to end users. The basic components of a transmission line are the structures/towers, conductors, insulators, foundations to support the structures, and shield wires to prevent lighting from striking conductors. See Figure 2 for a cross-section of a transmission line.

For a single-circuit transmission line, such as B2H, power is transmitted via three-phase conductors (a phase can also have multiple conductors, called a bundle configuration). These conductors are typically comprised of a steel core to give the conductor tensile strength and reduce sag and of aluminum outer strands. Aluminum is used because of its high conductivity to weight ratio.

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

Structures are designed to support the phase conductors and shield wires and keep them safely in the air. For the B2H project, structures were chosen to be primarily steel lattice tower structures, which provide an economical means to support large conductors for long spans over long distances.[7] The typical structure height for B2H is approximately 135 feet tall (structure height will vary depending on location) with a structure located roughly every 1,400 feet on average. The tower height and span length were optimized to minimize ground impacts and material requirements; taller structures could allow for longer spans (fewer structures on average per mile) but would be costlier due to material requirements. Again, the B2H tower and conductors were engineered to maximize benefits and minimize costs and impacts.

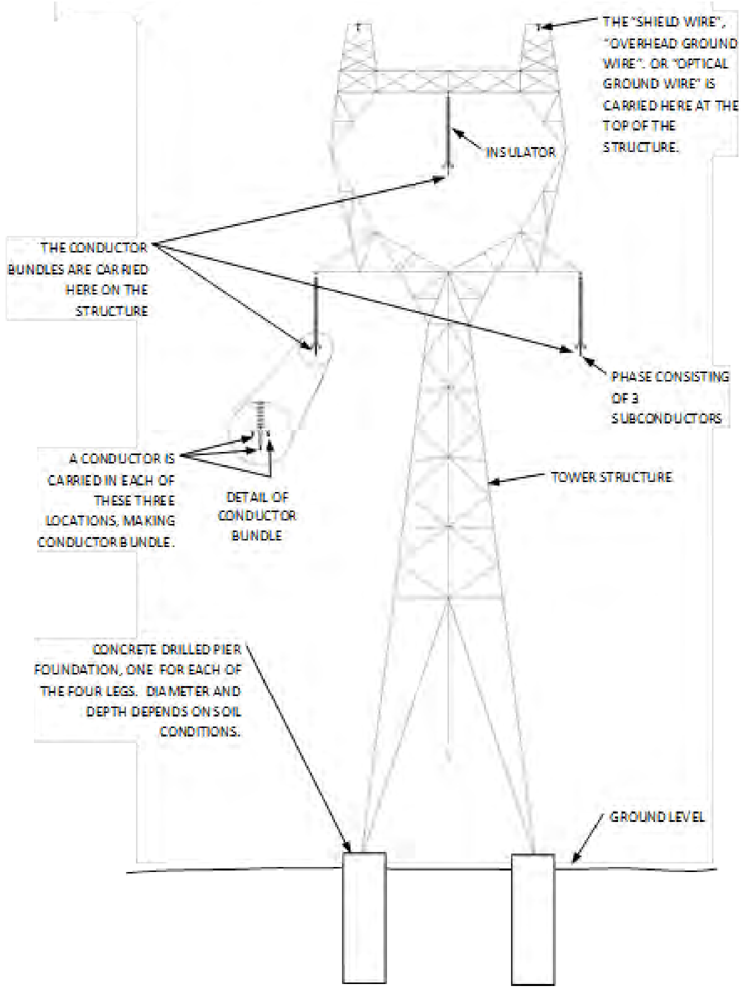

Figure 2. Transmission tower components

Transmission Line Structural Loading Considerations

Reliability and resiliency are designed into transmission lines. Overhead transmission lines have been in existence for over 100 years, and many codes and regulations govern the design and operation of transmission lines. Safety, reliability, and electrical performance are all incorporated into the design of transmission lines. Idaho Power's Energy Facility Siting

[7] H-frame towers, rather than lattice towers, will be used in certain locations to mitigate scenic impacts.

Council (EFSC) application includes an exhaustive list of standards. Several notable standards are as follows:

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

NESC provides for minimum guidelines and industry standards for safeguarding persons from hazards arising from the construction, maintenance, and operation of electric supply and communication lines and equipment. The B2H project will be designed, constructed, and operated at standards that meet, and in most cases, exceed, the provisions of NESC.

Physical loads induced onto transmission structures and foundations supporting the phase conductors and shield wires for the B2H project are derived from three phenomena: wind, ice, and tension. Under certain conditions, ice can build up on phase conductors and shield wires of transmission lines. When transverse wind loading is also applied to these iced conductors, it can produce structural loading on towers and foundations far greater than normal operating conditions produce. Design weather cases for the B2H project exceed the requirements in the NESC. As an example, for a high wind case, NESC recommends 90 miles per hour (mph) winds. The criteria proposed for this project is 100 mph wind on the conductors and 120 mph wind on the structures. There are multiple loading conditions that will be incorporated into the design of the B2H project, including unbalanced longitudinal loads, differential ice loads, broken phase conductors, broken sub-phase conductors, heavy ice loads, extreme wind loads, extreme ice and wind loads, construction loads, and full dead-end structure loads.

Transmission Line Foundation Design

The 500 kV single-circuit lattice steel structures require a foundation for each leg of the structure. The foundation diameter and depth shall be determined during final design and are dependent on the type of soil or rock present. The foundations will be designed to comply with the allowable bearing and shear strengths of the soil where placed. Soil borings shall be taken at key locations along the project route, and subsequent soil reports and investigations shall govern specific foundation designs as appropriate.

The 2017 NESC Rule 250A4 observes the structure capacity obtained by designing for NESC wind and ice loads at the specified strength requirements is sufficient to resist earthquake ground motions. Additionally, ASCE Manual No. 74 states transmission structures need not be designed for ground-induced vibrations caused by earthquake motion; historically, transmission structures have performed well under earthquake events,[8, 9] and transmission structure loadings caused by wind/ice combinations and broken wire forces exceed earthquake loads. It is common industry practice to design transmission line structures to withstand wind and ice loads that are equal to, or greater, than these NESC requirements.

Lightning Performance

The B2H project is in an area that historically experiences 20 lightning storm days per year.[10] This is relatively low compared to other parts of the United States. The transmission line will be designed to not exceed a lightning outage rate of one per 100 miles per year. This will be accomplished by proper shield wire placement and structure/shield wire grounding to adequately dissipate a lightning strike on the shield wires or structures if it were to occur. The electrical grounding requirements for the project will be determined by performing ground resistance testing throughout the project alignment, and by designing adequately sized counterpoise or using driven ground rods with grounding attachments to the steel rebar cages within the caisson foundations as appropriate.

Earthquake Performance

Experience has demonstrated that high-voltage transmission lines are very resistant to ground-motion forces caused by earthquake, so much so that national standards do not require these forces be directly considered in the design. However, secondary hazards can affect a transmission line, such as landslides, liquefaction, and lateral spreading. The design process considers these geologic hazards using multiple information streams throughout the siting and design process. For the current route, Idaho Power evaluated geologic hazards using available electronic (geographic information system [GIS]) data, such as fault lines, areas of unstable and/or steep soils, mapped and potential landslide areas, etc. Towers located in potential geologic hazards are investigated further to determine risk. Additional analysis may include field reconnaissance to gauge the stability of the area and subsurface investigation to determine the soil strata and depth of hazard. At the time of this report, no high-risk geologic

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[8] Risk Assessment of Transmission System under Earthquake Loading. J.M. Eidinger, and L. Kemper, Jr. Electrical Transmission and Substation Structures 2012, Pg. 183-192, ASCE 2013.

[9] Earthquake Resistant Construction of Electric Transmission and Telecommunication Facilities Serving the Federal Government Report. Felix Y. Yokel. Federal Emergency Management Agency (FEMA). September 1990.

[10] USDA RUS Bulletin 1751-801.

hazard areas have been identified. If—during the process of final design—an area is found to be high risk, the first option would be to micro-site, route around, or span over the hazard. If avoidance is not feasible, the design team would seek to stabilize the hazard. Engineering options for stabilization include designing an array of sacrificial foundations above the tower foundation to anchor the soil or improving the subsurface soils by injecting grout or outside aggregates into the ground. If the geotechnical investigation determines the problematic soils are relatively shallow, the tower foundations can be designed to pass through the weaker soils and embed into competent soils.

Wildfire

The transmission line steel structures are constructed of non-flammable materials, so wildfires do not pose a physical threat to the transmission line itself. However, heavy smoke from wildfires in the immediate area of the transmission line can cause flashover/arcing between the phase conductors and electrically grounded components. Standard operation is to de-energize transmission lines when fire is present in the immediate area of the line. Transmission lines generally remain in-service when smoke is present from wildfires not in the immediate vicinity of the transmission line. When compared to other resource alternatives, B2H may be more resilient to smoke. For instance, solar PV is susceptible to smoke, which can move into areas even if fires are not in the immediate vicinity of the solar generation. For example, the recent forest fires events in the Pacific Northwest caused heavy smoke along the proposed B2H corridor and in the Pacific Northwest in general. In the event of heavy smoke, the B2H line would likely still operate so long as the fires are not in the immediate area, whereas solar PV would likely operate at a much-reduced capacity.

Idaho Power has developed a Wildfire Mitigation Plan (WMP)[11]. This plan details how Idaho Power uses situational awareness of wildfire and weather conditions to change the way the system is operated. It also includes best practices that internal and contract crews follow for construction and maintenance activities during wildfire season, vegetation management practices, system and distribution hardening efforts. B2H has been included in this analysis as part of the planning process. Idaho Power filed an updated WMP to the OPUC by December 31, 2021, that included a Public Safety Power Shutoff plan and other items required. The updated plan will also be filed with the IPUC, likely in the first quarter of 2022. This plan will be reviewed annually and updated with new information and lessons learned as required.

[11] docs.idahopower.com/pdfs/Safety/2022Wildfire%20MitigationPlan.pdf

Wind Gusts/Tornados

Tornados are unlikely along the B2H route. As noted in the Transmission Line Structural Loading Considerations section, the B2H transmission line is designed to withstand extreme wind loading combined with ice loading.

Ice

Ice formation around the phase conductors and around the shield wires can add a substantial amount of incremental weight to the transmission line, putting extra force on the steel structures and foundations. As described in the Transmission Line Structural Loading Considerations section, the B2H transmission line is designed to withstand heavy ice loading combined with heavy wind loading.

Landslide

The siting and design process considers geologic hazards, such as landslides, liquefaction, and lateral spreading. See the Earthquake Performance section. Through the siting and design process, steep, unstable slopes are avoided, especially where evidence of past landslides is evident. During the preliminary construction phase, geotechnical surveys and ground surveys (light detection and ranging [LiDAR] surveys) help verify potentially hazardous conditions. If a potentially hazardous area cannot be avoided, the design process will seek to stabilize the area.

Flood

The identification and avoidance of flood zones was incorporated into the siting process and will be further incorporated into the design process. Foundations and structures can be designed to withstand flood conditions.

Direct Physical Attack

A direct physical attack on the B2H transmission line will remove the line’s ability to deliver power to customers. In the case of a direct attack, B2H is fundamentally no different than any other supply-side resource should a direct physical attack occur on a specific resource. However, because the B2H project is connected to the transmission grid, a direct physical attack on any specific generation site in the Pacific Northwest or Mountain West region will not limit B2H’s ability to deliver power from other generation in the region. In this context, B2H provides additional ability for generation resources to serve load if a physical attack were to occur on a specific resource or location within the region and therefore increases the resiliency of the electric grid as a whole.

If a direct physical attack were to occur on the B2H transmission line and force the line out of service, the rest of the grid would adjust to account for the loss of the line. Per the WECC facility rating process, the B2H capacity rating is such that an outage of the B2H line would not overload any other system element beyond equipment emergency ratings. Idaho Power also keeps a supply of emergency transmission towers that can be very quickly deployed to replace a damaged tower allowing the transmission line to be quickly returned to service.

B2H Design Conclusions

As evidenced in this section, the B2H project is designed to withstand a wide range of physical conditions and extreme events. Because transmission lines are so vital to our electrical grid, design standards are stringent. B2H will adhere to, and in most cases, exceed, the required codes or standards observed for high voltage transmission line design. This approach to the design, construction, and operation of the B2H project will establish utmost reliability for the life of the transmission line. Additionally, as discussed in the Direct Physical Attack section, transmission lines add to the resiliency of the grid by providing additional paths for electricity should one or more generation resources or transmission lines experience a catastrophic event.

B2H Capacity Interest

At the beginning of 2022, Idaho Power, PAC, and BPA executed a Non-Binding Term Sheet that addresses B2H ownership, transmission service considerations, and asset exchanges. As part of the Term Sheet, BPA will transition out of its role as a joint B2H permitting partner and will instead take transmission service from Idaho Power to serve its customers. Idaho Power will increase its B2H ownership to 45.45% by acquiring BPA's B2H capacity and will utilize a portion of this increased capacity to provide BPA transmission service across southern Idaho.

In the 2021 IRP, the company modeled B2H assuming the company's Term Sheet specified 45.45% project ownership share.

The Term Sheet defines Idaho Power and PAC's capacity interests in the B2H project and is representative of how Idaho Power studied B2H in the 2021 IRP. Table 4 details the B2H capacity interests of PAC and Idaho Power.

Table 4. B2H Term Sheet capacity interests

	Capacity Interest (West-to-East)	Capacity Interest (East-to-West)	Ownership %
Idaho Power	750 MW	0 MW	45.45%
PAC	300 MW	600 MW	54.55%
Unallocated		400 MW	

Idaho Power plans to have 750 MW of west-to-east capacity and a share of any east-to-west capacity that is ultimately unallocated—at this time, 45.45% of 400 MW, or 182 MW of east-to-west capacity associated with B2H. This represents an increase over the 2019 IRP when Idaho Power's interest was seasonally shaped, with 500 MW of west-to-east capacity from April through September, 200 MW of west-to-east capacity from January through March and October through December, and a reduced share of any unallocated capacity. Focusing on the west-to-east capacity, the difference between the 2019 IRP and the 2021 IRP represents a 250 MW increase in the summer capacity and a 550 MW increase in the winter capacity. Idaho Power will provide transmission service to BPA utilizing much of this incremental capacity. In both the summer and winter seasons, BPA's load forecast through the 2040 IRP planning period is less than this incremental capacity.

Capacity Rating—WECC Rating Process

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

Idaho Power completed the WECC Path Rating Process in November 2012 and achieved a WECC Accepted Rating of 1,050 MW in the west-to-east direction and 1,000 MW in the east-to-west direction. The B2H project, when constructed, will add significant reliability, resilience, and flexibility to the Northwest power grid.

B2H Project Coparticipants

PAC and BPA Needs

PAC and BPA are coparticipants in the permitting of the B2H project (also referred to as funders), with BPA planning to transition out per the Term Sheet discussed previously. Collectively, Idaho Power, PAC, and BPA represent a very large electric service footprint in the western US. The fact that three large utilities have each identified the value of the B2H project indicates the regional significance of the project and the value the project brings to customers throughout the West. More information about PAC's and BPA's needs and interest in the B2H project can be found in the following sections.

PAC

The following information was provided by PAC:

PAC is a locally managed, wholly owned subsidiary of Berkshire Hathaway Energy Company. PAC is a leading western United States energy services provider and the largest single owner of transmission in the West, serving 1.9 million retail customers in six western states. PAC is comprised of two business units: Pacific Power (serving Oregon, Washington, and California) and Rocky Mountain Power (serving Utah, Idaho, and Wyoming). Visit pacificorp.com for more information.

PAC's existing transmission path between the two balancing areas (PacifiCorp West [PACW] and PacifiCorp East [PACE]) consists of a single line (Midpoint, Idaho, to Summer Lake, Oregon) fully used during key operating periods, including winter peak periods in the Pacific Northwest and summer peak in the Intermountain West. PAC has invested in the permitting of the B2H project because of the strategic value of connecting the two regions. As a potential owner in the project, PAC would be able to use its bidirectional capacity to increase reliability and to enable more efficient use of existing and future resources for its customers. The following lists additional B2H benefits:

- **Customers:** PAC continues to invest to meet customers' needs, making only critical investments now to ensure future reliability, security, and safety. The B2H project will bolster reliability, security, and safety for PAC customers as the regional supply mix transitions.
- **Renewables:** The B2H project has been identified as a strategic project that can facilitate the transfer of geographically diverse renewable resources, in addition to other resources, across PAC's two balancing authority areas. Transmission line infrastructure, like B2H, is needed to maintain a robust electrical grid while integrating clean, renewable energy resources across the Pacific Northwest and Mountain West states. The PAC 2021 IRP Preferred Portfolio includes substantial new renewables facilitated by incremental transmission investments, demand-side management (DSM) resources, and significant storage resources. By the end of 2024, PAC's preferred portfolio includes more than 3,000 MW of renewables and nearly 700 MW of battery storage. At the end of the 20-year planning horizon in 2040, PAC's 2021 IRP Preferred Portfolio includes approximately 9,250 MW of new wind and solar. To support the addition of the new renewable resources typically located remotely from load centers and retirement of coal resources requires continued investment in a robust transmission system required to move resources across and between both PAC balancing areas.
- **Regional Benefit:** PAC, as a past member of the regional planning entity Northern Tier Transmission Group (NTTG), supported the inclusion of B2H in the NTTG 2018–2019

regional plan. PAC as a current member of the regional planning organization NorthernGrid has supported the inclusion of B2H into the 2020–2021 regional plan. From a regional perspective, the B2H project is a cost-effective investment that will provide regional solutions to identified regional needs. The project resolves possible system issues as identified in the NTTG 2018–2019 regional plan and the NorthernGrid 2020–2021 regional plan.

- **Balancing Area Operating Efficiencies:** PAC operates and controls two balancing areas. After the addition of B2H and portions of Gateway West, more transmission capacity will exist between PAC's two balancing areas, providing the ability to increase operating efficiencies. B2H will provide PAC 300 MW of additional west-to-east capability and 600 MW of east-to-west capability to move resources between PAC's two balancing authority areas.
- **Regional Resource Adequacy:** PAC is participating in the ongoing effort to evaluate and develop a regional resource adequacy program with other utilities that are members of the Northwest Power Pool. The B2H project is anticipated to provide incremental transmission infrastructure that will broaden access to a more diverse resource base, which will provide opportunities to reduce the cost of maintaining adequate resource supplies in the region.
- **Grid Resiliency:** The Midpoint-to-Summer Lake 500 kV transmission line is the only line connecting PAC's east and west control areas. The loss of this line has the potential to reduce transfers by 1,090 MW. When B2H is built, the new transmission line will provide redundancy by adding an additional 1,000 MW of capacity between the Hemingway Substation and the Pacific Northwest. This additional asset would mitigate the impact when the existing line is lost.
- **Oregon and Washington Renewable Portfolio Standards and Other State Legislation:** New legislation and rules for recently passed legislation are being developed to meet state specific policy objectives that are expected to drive the need for additional renewable resources. As these laws are enacted and rules are developed, PAC will evaluate how the B2H transmission line can help facilitate meeting state policy objectives by providing incremental access to geographically diverse renewable resources and other flexible capacity resources that will be needed to maintain reliability. PAC believes that investment in transmission infrastructure projects, like B2H and other Energy Gateway segments, are necessary to integrate and balance intermittent renewable resources cost effectively and reliably.
- **EIM:** PAC was a leader in implementing the western energy imbalance market (EIM). The real-time market helps optimize the electric grid, lowering costs, enhancing

reliability, and more effectively integrating resources. PAC believes the B2H project could help advance the objectives of the EIM and has the potential of benefitting PAC customers and the broader region.

- **Grid Reliability:** The loss of the Hemingway–Summer Lake 500 kV transmission line, the only 500 kV connection between the Pacific Northwest and Idaho Power, during peak summer load is one of the most severe possible contingencies the Idaho Power transmission system can experience. Once Hemingway–Summer Lake 500 kV disconnects, the transfer capability of the Idaho to Northwest path is reduced by over 700 MW in the west-to-east direction. After the addition of B2H, there will be two major 500 kV connections between the Pacific Northwest and Idaho Power. The Hemingway–Summer Lake 500 kV outage would become much less severe to Idaho Power's transmission system. Additionally, loss of the Hemingway–Summer Lake 500 kV line with heavy east-to-west power transfer out of Idaho to the Pacific Northwest results in significant system impacts. In this disturbance, an existing remedial action scheme (power system logic used to protect power system equipment) will disconnect over 1,000 MW of generation at the Jim Bridger Power Plant to reduce path transfers and protect bulk transmission lines and apparatus. Due to the magnitude of the generation loss, recovery from this disturbance can be extremely difficult. After the addition of B2H, this enormous amount of generation shedding will no longer be required. With two 500 kV lines between Idaho and the Pacific Northwest, the loss of one can be absorbed by the other. Keeping 1,000 MW of generation on the system for major system outages is important for grid stability.

BPA

BPA is a nonprofit federal power marketing administration based in the Pacific Northwest. BPA provides approximately 27% of the electric power used in the Pacific Northwest. BPA also operates and maintains about three-fourths of the high-voltage transmission in its service area. BPA's area includes Idaho, Oregon, Washington, western Montana, and small parts of eastern Montana, California, Nevada, Utah, and Wyoming. For more information, visit bpa.gov.

On January 19, 2022, BPA sent a letter to the region about B2H. This letter can be found on the following webpage:

bpa.gov/transmission/CustomerInvolvement/SEIdahoLoadService/Pages/default.aspx

Excerpt from the BPA letter to the region:

> The B2H with Transfer Service proposal presents a unique opportunity for BPA and other regional parties to work collaboratively together to support their respective goals of delivering firm, reliable, cost-effective power and

transmission service for their customers. The expected benefits of B2H with Transfer Service to the region in general, and BPA specifically, are multifaceted.

Regionally, B2H would increase the resiliency of the regional transmission system, including during severe weather conditions and during outages of other transmission facilities. Moreover, the combination of the B2H project (including the Midline Series Capacitor Project) along with other provisions in the Term Sheet would help to address existing operational issues involving transmission facilities in Oregon and Idaho. BPA also believes that the B2H project could support public policy objectives of bringing renewable resources to the region by reducing east to west transmission congestion between renewable resources located in Wyoming and Idaho and load centers on the west coast. Finally, it would also provide an additional outlet for surplus non-emitting resources from Washington and Oregon to displace remote emitting resources at certain times of the year.

For BPA specifically, the B2H with Transfer Service proposal would provide firm, stable, long-term transmission path to deliver federal power to BPA's SILS customers at an economical cost. The proposal would eliminate the double-wheel arrangement BPA currently uses to reach its loads, substantially reduce the risk of curtailments, and save BPA transmission and power purchase costs that occur under the interim plan. The B2H with Transfer Service proposal also avoids the complexities and complications of joint ownership and asset swaps originally considered in the B2H with Asset Swap proposal. Finally, B2H with Transfer Service results in greater projected transmission revenues for BPA as Idaho Power wheels over the federal transmission system to get to B2H. BPA will present its business case describing these savings and revenue projections and the overall value proposition for B2H with Transfer Service at a future workshop.

Additionally for BPA, the building of B2H will provide reinforcement for the Idaho-to-Northwest transmission path, also known as WECC Path 14. The substantial expansion of capacity across this path would likely be able to support reliable and cost effective long-term firm transmission service to several BPA customers, including BPA's other power customers currently located in Idaho Power's service territory. The increase in capacity at Path 14 would ensure these customers' access to federal power using the BPA network as well as the transmission capacity from the owners of the B2H project for their future load growth for years to come.

As a federal agency, BPA has responsibilities to comply with the National Environmental Policy Act (NEPA) and other legal requirements prior to making a final decision or taking any final agency action, such as committing to enter into transmission service contracts associated with the B2H project. Coincident with the signing of the Term Sheet, BPA has initiated a multi-step public process detailed in the aforementioned letter.

Coparticipant Agreements

Idaho Power, BPA, and PAC (collectively, the funders) entered a Joint Permit Funding Agreement on January 12, 2012. The agreement has been amended several times since 2012. The Amended and Restated Boardman to Hemingway Transmission Project Joint Permit Funding Agreement provides for the permitting (state and federal), siting, acquisition of ROW over public lands, the funding of preconstruction objectives, and acquisition of ROW options.

On January 18, 2022, the three B2H permit funding participants, Idaho Power, PAC, and BPA, executed a Non-Binding Term Sheet that addresses B2H ownership, transmission service considerations, and asset exchanges. The Term Sheet is described in the 2022 Term Sheet and B2H Project Partner Update section of this appendix.

Coparticipant Expenses Paid to Date

Approximately $125 million, including allowance for funds used during construction (AFUDC), have been expended on the B2H project through December 31, 2021. Pursuant to the terms of the joint funding arrangements, Idaho Power has received approximately $81 million of that amount as reimbursement from the project coparticipants as of December 31, 2021. Coparticipants are obligated to reimburse Idaho Power for their share of any future project permitting expenditures incurred by Idaho Power.

B2H Treasure Valley Integration Projects

The addition of the B2H project will require two 230 kV system integration projects to be completed on the Idaho Power system to create transmission capacity between Hemingway Substation and the Treasure Valley load area. These projects are estimated to cost approximately $35 million.

Hemingway–Bowmont #2 230 kV Line

A second transmission circuit will be added on the existing 13-mile Hemingway–Bowmont 230 kV line between the existing Hemingway Station near Melba, Idaho, to the existing Bowmont Station south of Nampa, Idaho.

Bowmont–Hubbard 230 kV Line

Integrating B2H into the Idaho Power system also will require a new 230 kV line from the existing Bowmont Station to the existing Hubbard Station east of Kuna, Idaho. This 16-mile line will be co-located with an existing 138-kV line on rebuilt transmission structures.

B2H INTEGRATED RESOURCE PLANNING

Resource Needs Evaluation and Markets

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

For the 2021 IRP, Idaho Power elected to use the AURORA model's long term capacity expansion modeling capability to develop optimal resource portfolios. Details regarding AURORA and the company's portfolio development process can be found in the main 2021 IRP report.

IRP Guideline Language—Transmission Evaluated on Comparable Basis

In Order No. 07-002, the OPUC adopted guidelines regarding integrated resource planning.[12]

> Guideline 5: Transmission. Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation *and electric transmission facilities as resource options*, taking into account their value for making additional purchases and sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving *reliability*.

Boardman to Hemingway as a Resource

B2H has proven to be a cost-effective resource through successive IRPs. When evaluating and comparing alternative resources, two major cost considerations exist: 1) the installation costs of the project (capital and other fixed costs), and 2) the energy costs of the project (variable costs). Installation costs are derived through cost estimates to install the various projects. B2H has the lowest fixed cost per kW of any resource evaluated, and the energy costs associated with Mid-C purchases are also very competitive. Energy costs are calculated through a detailed modeling analysis, using the AURORA software. Energy prices are derived based on inputs into the model, such as gas price, coal price, nuclear price, hydro conditions, and variable operations and maintenance (O&M).

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

Market Overview

Power Markets

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

Six characteristics of successful electric trading markets include the following:

1. The geographic location is a natural supply/demand balancing point for a particular region with adequate available transmission.
2. Reliable contractual standards exist for the delivery and receipt of the energy.
3. There is transparent pricing at the market with no single player nor group of players with the ability to manipulate the market price.
4. Homogeneous pricing exists across the market.
5. Convenient tools are in place to execute trades and aggregate transactions.
6. Most importantly, there is a critical mass of buyers and sellers that respond to the five characteristics listed above and actively trade the market on a consistent basis. This is the definition of liquidity, which is clearly the most critical requirement of a successful trading hub.

Mid-C Market

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

The Mid-C market exhibits all six characteristics of a successful electric trading market discussed above. Figure 3 shows the relative capacity of resources in the Northwest. This figure from the Pacific Northwest Utilities Conference Committee (PNUCC) assumes 8th percentile (critical) hydro generation and other resources set at utility defined peak capacity values. Even at critical hydro generation, the amount of hydro generation in the Northwest is significant.

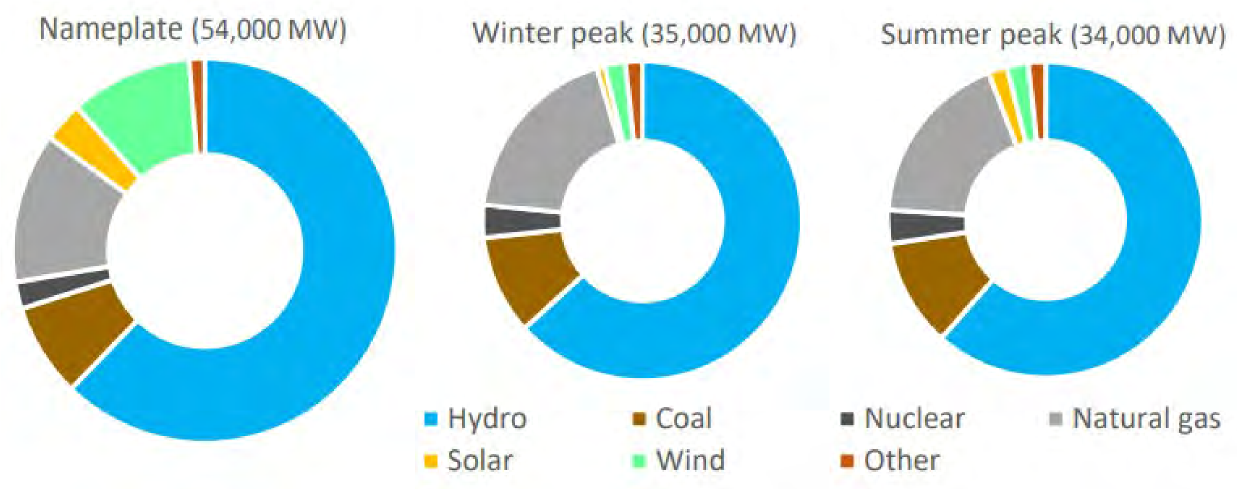

Figure 3. Northwest regional forecast (source: 2021 PNUCC)[13]

In the western United States, the other major market hubs are California–Oregon Border (COB), Four Corners (Arizona–New Mexico border), Mead (Nevada), Mona (Utah), Palo Verde (Arizona), and SP15 (California). The Mid-C market is very liquid. In 2020, on a day-ahead trading basis, daily average trading volume during heavy-load hours during June and July ranged from nearly 14,000 megawatt-hours (MWh) to nearly 32,000 MWh on the ICE platform alone. When combining heavy-load hours with light-load hours, on a day-ahead trading basis, the monthly volumes for June and July were each approximately 1,000,000 MWhs. These volumes are *in addition* to daily broker trades and month-ahead trading volumes, and only represent a fraction of the total transactions at Mid-C. Mid-C is by far the highest volume market hub in the west; frequently, Mid-C volumes are greater than the other hubs combined.

The following are some of the market participants that transact regularly at Mid-C. Additionally, numerous other independent power producers trade at Mid-C.

- Avista Utility
- BPA
- Chelan County PUD
- Douglas County PUD
- Eugene Water and Electric Board
- Idaho Power

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

- PAC
- Portland General Electric
- Powerex
- Puget Sound Energy
- Seattle City Light
- Tacoma Power

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

Mid-C and Idaho Power

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

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

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

Modeling of the Mid-C Market in the IRP

As part of the IRP analysis, Idaho Power uses the AURORA model to derive energy prices at all market hubs, including the Mid-C market. Energy prices are derived based on inputs into the model, such as gas price, coal price, nuclear fuel price, hydro conditions, Variable Energy Resources (VER) output, etc. Refer to main 2021 IRP document for more information on AURORA, forecast assumptions and modeling.

Energy purchases from the market require transmission to wheel the energy from the source to the utility purchasing the energy. Purchases from the Mid-C market would need to be wheeled across the BPA system to get the energy to the proposed Longhorn Substation near Boardman, Oregon. Idaho Power has submitted a transmission service request with BPA for this capacity that is a component of the 2022 Term Sheet discussed throughout this appendix.

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

B2H Capacity Analysis

Capacity Costs

Table 5 below provides capital costs for resource options found in the 2021 IRP to have the lowest cost from a capacity perspective. The capital costs for B2H in the table below reflect the inclusion of local interconnection costs for B2H.

Table 5. Total capital dollars ($)/kilowatt (kW) for select resources considered in the 2021 IRP (2021$)

Resource Type	Total Capital $/kW	Depreciable Life
B2H	$647[1]	55 years
Combined-cycle combustion turbine (CCCT) (1x1) F Class (300 MW)	$1,656	30 years
Simple-cycle combustion turbine —Frame F Class (170 MW)	$900	35 years
Reciprocating Gas Engine (55.5 MW)	$1,560	40 years
Solar PV—Utility-Scale 1-Axis (100 MW) + 4-hr Battery (100 MW)	$2,150	30 years[2]

[1] Uses the B2H 750-MW capacity.

[2] Depreciable life assumed for the solar component is 30 years and is 15 years for the storage component.

The B2H total capital cost per kilowatt at peak is roughly 70% of the cost of the next lowest-cost resource. Additionally, B2H, as a transmission line, will depreciate over 55 years compared to at most 40 years for a gas plant or 30 years for a solar plant. The low up-front cost and slower depreciation further reduces the rate impact to Idaho Power's customers. The summation of these factors show B2H is the lowest capital-cost resource by a substantial margin.

Energy Cost

B2H increases Idaho Power's transmission capacity to the Pacific Northwest and enables additional purchased power from the Mid-C hub at both peak times and when energy prices are favorable relative to the costs of Idaho Power's existing resource fleet. The company believes that the increasing penetration of VERs, with their zero cost of energy, will depress market prices in the future. The company will be able to leverage B2H to make economic low-cost energy purchases.

B2H Comparison to Other Resources

The 2021 IRP provides an in-depth analysis of the B2H project compared to alternative resource options. Table 6 summarizes some of the high-level differences between B2H and other notable resource options.

Table 6. High-level differences between resource options

	B2H	Reciprocating engines	CCCT	Lithium batteries (4-Hr)	1-axis solar PV
Variable renewable					✓
Dispatchable capacity providing	✓	✓	✓	✓	
Non-dispatchable (coincidental) capacity providing					✓
Balancing, flexibility providing	✓	✓	✓	✓	
Energy providing	✓	✓	✓		✓
Variable costs (primary variable cost driver)	Mid-C market	Natural gas	Natural gas	Purchased power	No variable costs
Capital costs	\$647 per on-peak kW	\$1,560 per kW	\$1,656/kW	\$1,150 per kW	\$1,000 per kW
Fuel price risk		✓	✓		
Wholesale power market price risk	✓			✓	
Other	Expanded access to market (Mid-C) providing abundant clean, renewable energy, highly reliable (low forced outage), as long-lived resource promotes stability in customer rates, benefit to regional grid, supports	Scalable (modeled generators 55.5-MW nameplate), relatively short-lead, very flexible resource, range driven by plant configuration.	Relatively short-lead resource, dispatchable, recent construction experience.	Uncertainty related to performance (e.g., # of lifetime cycles), dispatchable, scalable, potential for geographic dispersion.	Renewable, clean, scalable (modeled plants 100-MW nameplate), diminishing on-peak contribution with expanded penetration, short-lead resource, variable.

	B2H	Reciprocating engines	CCCT	Lithium batteries (4-Hr)	1-axis solar PV
	Idaho Power's clean energy goal, long-lead resource.				

Notes:

1 Provided capital costs are in nominal 2021 dollars.

2 Solar is not dispatchable but tends to produce at fairly high levels during summer periods of high customer demand.

3 Lithium battery is a net energy consumer (roundtrip efficiency = 85%). Lithium battery provides energy during heavy load hours or other high energy demand/high energy value periods; battery recharge costs tied primarily to Mid-C market costs or variable costs of Idaho Power's system resources during light load hours.

BPA Southeast Idaho Customer Loads

As described in the 2022 Term Sheet and B2H Project Partner Update section, BPA intends to transition out of its role as a joint B2H permitting partner and to rely on the completed B2H project to take transmission service from Idaho Power to serve its customers in southeast Idaho. Idaho Power's B2H capacity will increase from an average of 350 MW west-to-east to 750 MW west-to-east and Idaho Power will utilize a portion of its increased B2H capacity to provide BPA network transmission service across southern Idaho. The six BPA southeast customers that will be served via this new network transmission service are listed in Table 7. Collectively, these BPA southeast Idaho customer loads are winter peaking and have a high offset by internal BPA network resources, primarily Palisades Power Plant, during the summer months. Given these characteristics, the load service coordinates very well with Idaho Power's planned summer peaking load pattern and expected B2H usage for imports to serve Idaho Power native load customers.

Table 7. BPA southeast (SE) Idaho Customers

BPA SE Idaho Customers
City of Idaho Falls
Lower Valley Energy
Fall River Rural Electric Cooperative
City of Soda Springs
Salmon River Rural Electric Cooperative
Lost River Electric Cooperative

B2H BENEFITS AND VALUES

Capacity

High-voltage transmission lines provide many significant benefits to the Western Interconnection. The most significant benefit of the B2H project is the capacity benefit of the transmission line. Idaho Power is developing the B2H project to create capacity to serve peak customer demand. The capacity benefit is described in more detail in the B2H Integrated Resource Planning section of this appendix.

The Pacific Northwest is a winter peaking region. Pacific Northwest utilities continue to install and build generation capacity to meet winter peak regional needs. Idaho Power operates a system with an early summer peak demand. Idaho Power's peak occurs in the late June/early July timeframe because of its irrigation load. Idaho Power's peak aligns well with spring hydro runoff conditions when the Pacific Northwest is flush with surplus power capacity.

The existing transmission system between the Pacific Northwest and Idaho Power is constrained. Constructing B2H will alleviate this constraint and add 1,050 MW of transfer capability between the Pacific Northwest and Idaho Power (2,050 MW total bi-directionally). Both the Pacific Northwest and Idaho Power will significantly benefit from the addition of transmission capacity between the regions by leveraging the diversity of their respective seasonal demand and generation profiles. The Pacific Northwest has already built the power plants and would benefit from selling energy to Idaho Power. Idaho Power needs resources to serve peak load, and a transmission line to existing, underutilized power plants is much more cost effective than building a new power plant.

Clean Energy Future

The benefits of B2H in aggregate reflect its importance to the achievement of Idaho Power's goal to provide 100% clean energy by 2045 without compromising the company's commitment to reliability and affordability. In-depth studies and experts, such as the American Clean Power Association, cite the need for an expanded and robust transmission system in a decarbonized future.[14] Indeed, the Americans for a Clean Energy Grid highlighted B2H as one of 22 projects that were needed to enable the interconnection of around 60,000 MW of additional renewable

[14] cleanpower.org/wp-content/uploads/2021/01/June-2021_Transmission-Fact-Sheet.pdf
utilitydive.com/news/as-operators-update-grid-planning-for-renewables-transmission-remains-key/505065/
pv-magazine-usa.com/2019/08/30/clean-energy-groups-allies-call-for-overhaul-of-the-transmission-grid/

capacity in the United States.[15] A *Net Zero America* report by Princeton[16] concluded that the United States will need to expand its electricity transmission system by 60% by 2030 in order to achieve net-zero emissions by 2050.

Leverage Regional Diversity

In the early days of the electric grid, utilities built individual power plants to serve their local load. Utilities quickly realized that if they interconnected their systems with low-cost transmission, the resulting diversity of load reduced their need to build power plants. Utilities also realized that transmission allowed them to build and share larger, more cost-effective, and more efficient power plants. The same opportunities exist today. In fact, B2H is being developed to take advantage of existing diversity.

Table 8 illustrates peak-load estimates, by utility and season, for 2030. As seen in the table, there is significant diversity of load among the utilities and between the western and eastern side of the entire Northwest. The "Maximum (MW)" column illustrates the minimum amount of generating capacity that would be required if each utility were to individually plan and construct generation to meet their own peak load need of 71,900 MW. When all utilities plan together, the total generating capacity can be reduced to 63,500 MW, a more than 10% reduction. Also note that the Western Northwest (NW) regions have a total winter peak that is 8,200 MW higher than its summer peak. On the other hand, the Eastern NW regions have a total summer peak that is 9,400 MW more than its winter peak. Transmission connections between the regions, such as B2H, are the key to sharing installed generation capacity.

Table 8. 2030 peak load estimates—illustration of load diversity between western regions

Region	Summer Peak (MW)	Winter Peak (MW)	Maximum (MW)
Avista	2,200	2,400	2,400
BPA	10,100	12,900	12,900
British Columbia	9,100	12,200	12,200
Chelan	300	500	500
Douglas	300	500	500
Grant	1,500	1,400	1,500
PAC—West	3,800	4,000	4,000
Portland General	3,900	3,800	3,900
Puget Sound	4,200	5,200	5,200
Seattle City	1,200	1,600	1,600
Tacoma	600	900	900

[15] https://cleanenergygrid.org/wp-content/uploads/2021/09/Transmission-Projects-Ready-to-Go.pdf

[16] https://netzeroamerica.princeton.edu/img/Princeton_NZA_Interim_Report_15_Dec_2020_FINAL.pdf

Region	Summer Peak (MW)	Winter Peak (MW)	Maximum (MW)
Western NW Total	**37,200**	**45,400**	**45,600**
Idaho Power	4,500	2,900	4,500
Nevada	9,100	4,100	9,100
Northwestern Energy	2,100	2,100	2,100
PAC—East	10,600	7,800	10,600
Eastern NW Total	26,300	16,900	26,300
Total	**63,500**	**62,300**	**71,900**

Note: From EEI Load Data used for the WECC 2030 ADS PCM

Load diversity occurs seasonally, as illustrated in Table 8, but it also occurs sub-seasonally and daily. An additional major variable in the Northwest is hydroelectric generation diversity. Over the winter, water accumulates in the mountains through snowpack. As this snow melts, water flows through the region's hydroelectric dams, and northwest utilities generate a significant amount of power. During the spring runoff, generation capacity available in the Pacific Northwest can be significantly higher than in the winter or even late summer. Idaho Power is fortunate to have a peak load that is coincident with the late spring/early summer hydro runoff. Idaho Power's peak load occurs in late June/early July, when hot weather causes major air-conditioning load coincident with agricultural irrigation/pumping load. Idaho Power's time window for a significant peak is quite short, with agricultural irrigation/pumping load starting to ramp down by mid-July.

Capacity to Four Corners Market Hub

As part of the 2022 Term Sheet detailed earlier in this appendix, Idaho Power will acquire PAC transmission assets and their related capacity sufficient to enable Idaho Power to utilize 200 MW of bidirectional transmission capacity between the Idaho Power system (Populus) and Four Corners, through Mona. Four Corners is a Desert Southwest market hub and eight entities with transmission have connectivity to the Four Corners market hub. Idaho Power will also have a connection to entities at Mona in central Utah.

Table 9. List of transmission entities at Four Corners and Mona

Entities with Transmission at Four Corners	Entities with Transmission at Mona
Arizona Public Service	Intermountain Power Agency (LADWP)
Salt River Project	PAC
Tri State G&T	
Western Area Power Admiration	
Xcel Energy	
PNM	
Tucson Electric Power Company	
PAC	

Idaho Power believes that the acquired Four Corners capacity will provide the company with long-term strategic value diverse from B2H. The Desert Southwest is rich with solar potential which is expected to continue its significant growth in the future, New Mexico has significant wind potential, and the number of Desert Southwest entities with a presence at this market hub presents significant market diversity opportunities. Idaho Power believes additional access to this market hub during the winter months will prove to be extremely valuable in a low carbon future.

The transmission assets between Idaho and Four Corners will provide a valuable firm transmission connection to a market hub that is diverse from Mid-C. In essence, the B2H project is enabling two diverse connections to two major western market hubs. As a conservative planning approach, this additional 200 MW of import capacity is set to zero in planning margin calculations for the summer peaking months. The diversity of capacity from multiple market hubs solidifies and supports that the overall B2H project capacity will achieve 500 MW of peak import capacity into Idaho Power.

Borah West and Midpoint West Capacity Upgrades

As part of the 2022 Term Sheet, transmission capacity on the Idaho Power operated Borah West and Midpoint West transmission paths must be upgraded to support additional east-to-west schedules required by Idaho Power and PAC across southern Idaho. There are two system upgrade projects identified to reinforce Borah West and Midpoint West to enable these increased east-to-west transmission flows through Idaho:

1. **Midpoint–Kinport 345 kV Series Capacitor Addition:** The addition of a series capacitor on the existing Midpoint–Kinport 345 kV line will increase the Borah West path rating by approximately 500 MW. This series capacitor allows for more optimal distribution of flows on the existing 345 kV lines west of Borah Station near American Falls, Idaho.
2. **Midpoint 500/345 kV Second Transformer Addition:** The existing single 500/345 kV transformer bank is a bottleneck for increased flows across the Idaho system. A second 500/345 kV transformer will need to be installed to increase the capacity of the existing Midpoint–Hemingway 500 kV line to accommodate higher east-to-west transfers across Idaho to Hemingway.

These upgrades will net an approximate 600 MW increase in capacity across southern Idaho and enable PAC's usage of its B2H capacity. Additionally, Idaho Power will be relieved of its 510 MW long-term point-to-point transmission service obligation across southern Idaho and be able to repurpose this transmission to integrate new resources (many identified in the 2021 IRP Preferred Portfolio) for Idaho Power customer benefit.

Improved Economic Efficiency

Transmission congestion causes power prices on opposite sides of the congestion to diverge. Transmission congestion is managed by dispatching higher cost, less efficient resources to ensure the transmission system is operating securely and reliably. Congestion can have a significant cost. During peak summer conditions, the Idaho to Northwest path in the west-to-east direction can become constrained and power prices in Idaho and to the east can generally be high, while power prices in the Pacific Northwest can be depressed due to a surplus of power availability without adequate transmission capacity to move the power out of the region. The construction of B2H will help alleviate this constraint and create a win–win scenario where generators in the Pacific Northwest will be able to gain further value from their existing resource, and load-serving entities in the Mountain West region will be able to meet load service needs at a lower cost. The reverse situation is true as well—the Pacific Northwest will benefit from economical resources from the Mountain West region during certain times of the year.

Renewable Integration

To facilitate a transition from coal and fossil fuel resources to meet Idaho Power and surrounding states' clean energy goals, the region requires new and upgraded transmission capacity to integrate and balance variable energy resources like wind and solar. Existing renewable generation is, at times, curtailed due to a lack of transmission capacity to move the energy to load. B2H can facilitate the transfer of geographically diverse renewable resources across the western grid and help ensure our clean energy grid of the future is robust and reliable.

Grid Reliability/Resiliency

Transmission grid disturbances do occur. B2H will increase the robustness and reliability of the regional transmission system by adding additional high-capacity bulk electric facilities designed with the most up-to-date engineering standards. Major 500 kV transmission lines, such as B2H, substantially increase the grid's ability to recover from unexpected disturbances. Unexpected disturbances are difficult to predict, but below are a few examples of disturbances whose impacts would be reduced with the addition of B2H:

1. Loss of the Hemingway–Summer Lake 500 kV line with heavy west-to-east power transfer into Idaho. The loss of the Hemingway–Summer Lake 500 kV transmission line, the only 500 kV connection between the Pacific Northwest and Idaho Power, during peak summer load is one of the worst possible contingencies the Idaho Power transmission system can experience. Once Hemingway–Summer Lake 500 kV disconnects, the transfer capability of the Idaho to Northwest path is reduced by over

700 MW in the west-to-east direction. After the addition of B2H, there will be two major 500 kV connections between the Pacific Northwest and Idaho Power. The Hemingway–Summer Lake 500 kV outage would become much less severe to Idaho Power's transmission system.

2. Loss of the Hemingway–Summer Lake 500 kV line with heavy east-to-west power transfer out of Idaho to the Pacific Northwest. In this disturbance, an existing remedial action scheme (power system logic used to protect power system equipment) will disconnect over 700 MW of generation at the Jim Bridger Power Plant or Wyoming Wind to reduce path transfers and protect bulk transmission lines and apparatus. Due to the magnitude of the generation loss, recovery from this disturbance can be extremely difficult. After the addition of B2H, this sizable amount of generation shedding will no longer be required. With two 500 kV lines between Idaho and the Pacific Northwest, the loss of one can be absorbed by the other. Keeping 700 MW of generation on the system for major system outages is important for grid stability.
3. Loss of a single 230 kV transmission tower in the Hells Canyon area. Idaho Power owns two 230 kV transmission lines, co-located on the same transmission towers, that connect Idaho to the Pacific Northwest. Because these lines are on a common tower, Idaho Power must consider the simultaneous loss of these lines as a realistic planning event. Historically, such an outage did occur on these lines in 2004 during a day with high summer loads. By losing these lines, Idaho Power's import capability was dramatically reduced, and Idaho Power was forced to rotate customer outages for several hours due to a lack of resource availability. After the addition of B2H, the impact of this outage would be substantially reduced.

Resource Reliability

The forced outage rate of transmission lines has historically been lower than traditional generation resources. Availability and contribution to resource adequacy on the power grid vary significantly by resource type. The North American Electric Reliability Corporation (NERC) has historically tracked transmission availability through a Transmission Availability Data System (TADS) and generation availability through a Generation Availability Data System (GADS) in North America. Outage statistics between transmission and generation differ, as transmission varies in voltage class and total line length, while generators mostly differ in total size and fuel type. A telling sign of the reliability of a generation resource is the equivalent forced outage rate (EFORd). The EFORd is calculated based on the amount of time a generator or a transmission line, is either de-rated, or completely forced out of service, while needed.

De-rating a generator or a transmission line, would be considered a partial outage, based on the de-rate amount as a percentage of the total capacity.

Table 10 provides the EFORd values used in the 2021 IRP. The EFORd values were obtained from the company historical data and from the latest data available in GADS and TADS at the time of the analysis.[22]

Table 10. NERC forced-outage rate information for different resources

Generation Type	Unit Size	EFORd
Coal	All Sizes	6.34%–9.18%
Hydro	All Sizes	3.6%
Gas Simple Cycle	All Size	4.44%–7.3%
Gas Combined Cycle	>200 MW	2.0%
New Transmission	400-599 kV	0.25%

From the NERC TADS data, a 300-mile, 500 kV transmission line (B2H) would be expected to have an equivalent forced outage rate of 0.25%; the B2H transmission line is expected to have 99.75% availability when needed.

A transmission line with a forced outage rate of less than 1% is significantly more reliable than a power plant, as shown in Table 10. Of course, a transmission line requires generating resources to provide energy to the line to serve load. However, energy sold as "Firm" must be backed up and delivered even if a source generator fails. Therefore, Firm energy purchases would have an EFORd consistent with the transmission line, which is more reliable than traditional supply-side generation. In the management of cost and risk, B2H will provide Idaho Power's operators additional flexibility when managing the Idaho Power resource portfolio.

As described in the *2021 IRP Appendix C–Technical Report*, Idaho Power evaluated the Loss of Load Expectation for each IRP portfolio. Figure 4 depicts the additional Simple Cycle Combustion Turbine equivalent generation capacity required to maintain the Preferred Portfolio (Base with B2H) and the Base without B2H PAC Bridger Alignment portfolio (the least-cost portfolio that did not include B2H) within the desired reliability threshold.

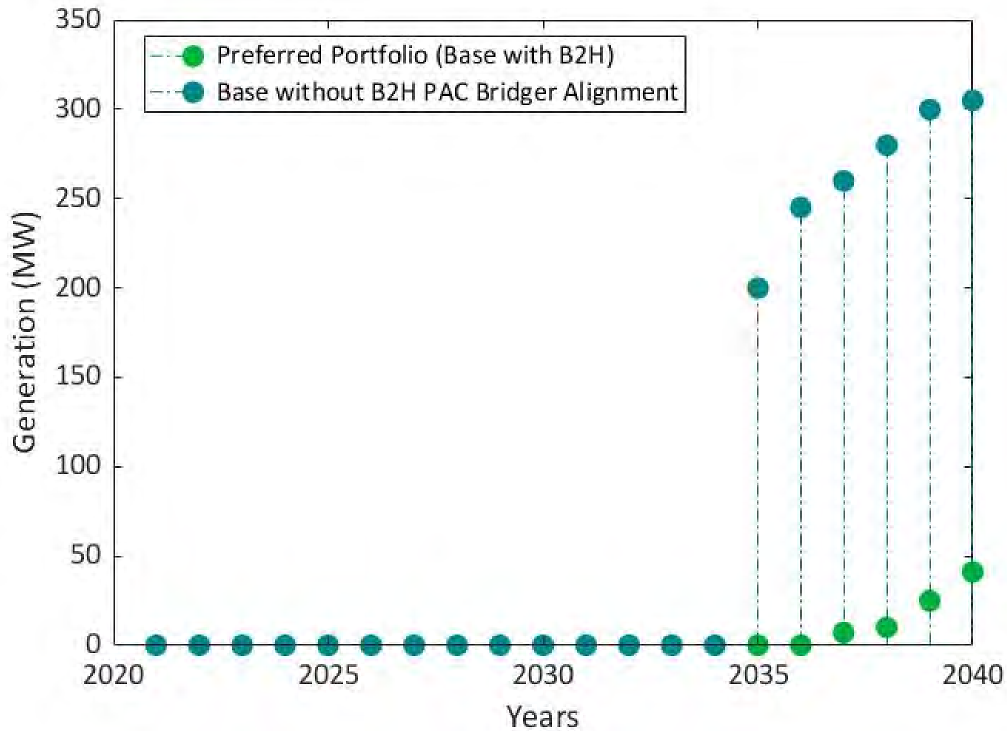

Figure 4. Additional generation required to achieve 0.05 LOLE by portfolio

Figure 4 shows that the Preferred Portfolio (Base with B2H) is significantly more reliable than the best portfolio that did not include B2H.

Contingency Reserves

During real-time operations, Idaho Power holds generation in reserve to meet its contingency reserve obligation. As a requirement of NERC BAL-002-WECC-2a, Idaho Power has an obligation to hold generation in reserve equaling at least 3% of network demand plus 3% of internal generation. For market purchase imports, the 3% contingency requirement for the generation is not borne by Idaho Power. The producer in the external balancing area is required to meet the 3% reserve obligation associated with its resource. Compared to an internal resource located within the Idaho Power area, imported market purchases reduce Idaho Power's reserve obligation.

Idaho Power plans to make additional market purchases with B2H. The selling entity will carry the contingency reserve obligation. This reduction in reserve obligation will offset the additional reserve obligations taken on by the company through the increased amount of BPA customer network load and generation in the Idaho Power area. Table 11 details the increase in transmission network customer reserve obligations being offset by reduced reserve obligations from market purchases. Idaho Power's reserve obligation during summer peak is still reduced with B2H compared to a replacement internal resource.

Table 11. Change in Idaho Power contingency reserve obligation with B2H

	Change in Summer Peak Network Demand	Change in Summer Peak Network Resource	Change in Reserve Obligation
New BPA Southeast Customer Idaho Network Load and Gen	~325 MW	~145 MW	14.1 MW
Idaho Power Market Purchases via B2H Instead of a New Internal Resource	-	(500 MW)	(15 MW)
Total	**-**	**-**	**(0.9 MW)**

Reduced Electrical Losses

During peak summer conditions, with heavy power transfers on the Pacific Northwest and Idaho Power transmission systems, the addition of the B2H project is expected to reduce electrical losses by nearly 100 MW across the Western Interconnection (factoring in more than just Idaho Power's system). This is a considerable savings for the region; 100 MW of generation, that customers ultimately pay for, does not need produced to supply losses alone. Electrical losses add to the demand level that needs to be supplied by the power system.

Losses on the power system are caused by electrical current flowing through energized conductors, which in turn create heat. Losses are equal to the electrical current squared times the resistance of the transmission line:

$$Electrical\ Losses = Current^2 \times Resistance$$

From the electrical losses equation above, if the current doubles, the electrical losses will increase by a factor of four. By constructing the B2H line, less efficient (i.e., lower voltage) transmission lines with very large transfers are relieved, reducing the electrical current through these lines and dramatically reducing the losses due to heat.

The electrical losses vary throughout the year depending on flow levels on the lines.
To determine an average electrical loss saving benefit for Idaho Power resulting from the B2H project, various seasonal WECC power flow base cases were utilized to simulate flow conditions with and without the addition of B2H. The Idaho Power area transmission losses from simulated base case scenarios are shown in Table 12. In six of the seven cases the B2H project resulted in a beneficial reduction of losses in the Idaho Power balancing area.

Table 12. Idaho Power area losses from powerflow cases pre- and post-B2H

Powerflow Case	Idaho Power Losses		
	Pre-B2H	Post-B2H	Change (MW)
Peak Summer	207.2 MW	176.5 MW	-30.7 MW
Peak Summer NW Import	185.6 MW	159.3 MW	-26.3 MW
Peak Winter	97.8 MW	87.3 MW	-10.5 MW
Off Peak Summer	82.9 MW	75.7 MW	-7.2 MW
Off Peak Winter	61.1 MW	61.3 MW	0.2 MW
Off Peak Light NW Export	106.8 MW	106.0 MW	-0.8 MW
Off Peak Heavy NW Export	189.4 MW	180.2 MW	-9.2 MW

The above loss benefits in Table 12 are for seven specific powerflow hours. To develop an average loss savings benefit for B2H that considers all flow hours, regression analysis was performed to develop quadratic equation coefficients that relate path flows to predicted energy loss savings. Next, historical transmission path flows from the previous five years were captured and analyzed with developed loss savings coefficients. The result of the analysis was an Idaho Power 6.4 MW average electrical loss savings with the addition of B2H. This 6.4 MW average loss saving benefit was utilized as an input in the B2H scenarios for the 2021 IRP. For IRP portfolios with B2H included, the Idaho Power load was reduced by 6.4 MW during all hours to capture the value of this reduction in electrical losses.

Flexibility

Advances in technology are pushing some generation resources, such as coal plants, toward economic obsolescence. Any supply-side resource alternative could face the same economic obsolescence in the future. B2H is an alternative to constructing a new supply-side resource and, therefore, reduces the risk of technological obsolescence. B2H will facilitate the transfer of any generation technology, ensuring Idaho Power customers always have access to the most economic resources, regardless of the resource type.

B2H capacity, when not used by B2H owners, will be available (for purchase) to other parties to make economic interstate west-to-east and east-to-west power transfers for more efficient regional economic dispatch. This provides a regional economic benefit to utilities around Idaho Power that is not factored into the analysis. Specifically, the B2H project will make additional capacity available for Pacific Northwest utilities to sell energy to southern and eastern markets in the west, and for Pacific Northwest utilities to purchase energy from southern and eastern markets to meet their winter peak load service needs (southern and eastern WECC entities are mostly summer peaking). Idaho Power customers benefit from any third-party transmission purchases as the incremental transmission revenue acts to offset retail customer costs.

The existing electric system is heavily used. Because the system is so heavily used, new transmission line infrastructure, like B2H, creates additional operational flexibility. B2H will increase the ability to take other system elements out of service to conduct maintenance and will provide additional flexibility to move needed resources to load when outages occur on equipment.

EIM

Idaho Power views the regional high-voltage transmission system as critical to the realization of EIM benefits. The expansion of this transmission system, through the addition of B2H, will facilitate further benefits by increasing transmission capacity between Idaho Power and other EIM participants. As fluctuations in supply and demand occur for EIM participants, the market system will automatically find the best resource(s) from across the large-footprint EIM region to meet immediate power needs. Additional Northwest utilities are joining the EIM increasing the value the transmission system provides. This activity optimizes the interconnected high-voltage system as market systems automatically manage congestion, helping maintain reliability while also supporting the integration of variable energy resources and avoiding curtailing excess supply by sending it to where demand can use it.

Idaho Power notes that its participation in the EIM does not alter its obligations as a balancing authority (BA) required to comply with all regional and national reliability standards. Participation in the western EIM does not change NERC or WECC responsibilities for resource adequacy, reserves, or other BA reliability-based functions for a utility.

Transmission capacity and connectivity is critical to evolution of markets in the west. Market expansion efforts such as the California Independent System Operator's (CAISO) Energy Day-Ahead Market (EDAM) or the Southwest Power Pool's (SPP) markets both look to optimize transmission between entities to capture diversity of resources and loads. Greater transmission transfer capacity between participants in a market reduces congestion costs and allows the lowest cost energy to reach a wider load footprint. Transmission benefits customers in both the EIM and expanded markets through increased competition and liquidity as customers gain access to a wider set of generators through an optimized market dispatch.

B2H Complements All Resource Types

Utility-scale resource installations allow economies of scale to benefit customers in the form of lower cost per watt. For instance, residential rooftop solar is growing in popularity, but the economics of rooftop solar are outweighed by the economics of utility-scale solar installation.[17] Large transmission lines allow the most economical resources to be sited in the most economical locations. As an example, in the 2021 IRP, wind in Idaho is expected to have a capacity factor of approximately 35% (where the capacity factor is the amount of time the system generates relative to its nameplate rating over the course of a year). Comparatively, wind in Wyoming has a capacity factor of 45%. If wind installation costs are assumed to be equivalent in Idaho and Wyoming, a Wyoming installation would generate over 28% more energy over the course of the year. Transmission lines provide the ability to move the most economical resources around the region.

Idaho Power views transmission lines like B2H as a complement to any resource type that allows access to the least-cost and most efficient resource, as well as regional diversity, to benefit all customers in the West.

B2H Benefits to Oregon

Economic and Tax Benefits

The B2H project will result in positive economic impacts for eastern Oregon communities in the form of construction jobs, economic support associated with infrastructure development (i.e., lodging and food), and increased annual tax benefits to each county for project-specific property tax dollars. The annual tax benefit of the line is shown in Table 13 below. Idaho Power anticipates the project will add about 500 construction jobs, which will provide a temporary increase in spending at local businesses.

Table 13. Projected annual B2H tax expenditures by county*

Oregon County	Property Tax
Morrow	$318,040
Umatilla	$421,048
Union	$1,002,165
Baker	$1,815,398
Malheur	$2,241,157
Total Oregon Tax Benefit	**$5,797,808**

*The property tax valuation process for utilities is determined differently than locally assessed commercial and residential property. The Oregon Department of Revenue determines the property tax value for Idaho Power's property (transmission, distribution, production, etc.) as one lump sum value (i.e., not by individual assets). The Oregon Department of Revenue then apportions and remits Idaho Power's lump sum assessed value to each county. It is from those values that the county generates property tax bills for the company. Idaho Power converts its Oregon property tax payment by county into an internal rate that can be applied to Idaho Power's transmission, distribution, and production book investment to estimate taxes. This internally calculated tax rate is what was applied to the B2H estimated book investment (project cost) to estimate property taxes. The table above summarizes the tax value derivation. For estimation purposes, the estimated property taxes are assumed at Idaho Power tax rates. PAC property taxes may differ from Idaho Power's property taxes.

[17] The National Renewable Energy Laboratory (NREL) estimates the cost of residential rooftop solar (PV) is nearly 2.5 times the cost of utility-scale solar on a $/Watt basis (NREL, Annual Technology Baseline: Electricity: 2019).

Local Area Electrical Benefits

The B2H project will add 1,050 MW of additional transmission connectivity between the BPA and Idaho Power systems. Currently, the transmission connections between BPA and Idaho Power are fully committed for existing customer commitments. Along the B2H line route, Idaho Power currently serves customers in Idaho's Owyhee County and in Oregon's Malheur County and portions of Baker County. PAC, through Pacific Power, serves portions of Umatilla County. BPA provides transmission service to local cooperatives in the remainder of the project area in Morrow, Umatilla, Union, and Baker counties. Below is a summary of how these areas will benefit directly from B2H.

La Grande and Baker City are served by the Oregon Trails Electric Cooperative (OTEC). Portions of Morrow County and Umatilla County are served by Umatilla Electric Cooperative (UEC) and Columbia Basin Electric Cooperative (CBEC). OTEC, UEC, and CBEC pay BPA's network transmission rate to receive transmission service from the BPA system. BPA is kicking off a public process related to B2H in 2022, and Idaho Power expects BPA's business case will show B2H is a cost-effective solution to meet BPA customer needs. Correspondingly, given the sharing of BPA's transmission costs, OTEC, UEC, and CBEC customers would also benefit from this cost-effective solution.

The B2H project provides economic development opportunities. The cost of power is a major factor in economic development and—as discussed previously—B2H, as a low-cost resource alternative, will keep power costs low compared to more expensive alternatives.

Capacity must be available on the existing system for additional economic development to take place. In Union and Umatilla counties, BPA's McNary–Roundup–La Grande 230 kV line has limited ability to serve additional demand in the Pendleton and La Grande areas but is currently capable of meeting the 10-year load forecast. The B2H project will increase the transfer capability through eastern Oregon by 1,050 MW. This capacity will provide a significant regional benefit to the entire Northwest and specifically benefit load service to eastern Oregon and southern Idaho. It is possible this added capacity resulting from the B2H project could be used to serve additional demand in Union and Umatilla counties.

Portions of Baker County are served by Idaho Power, including the communities of Durkee and Huntington. BPA currently provides energy to OTEC, which serves Baker City via transmission connections between the Northwest and Idaho Power's transmission system. The existing transmission connections between the Northwest and Idaho Power are fully used for existing load commitments, with very little ability to meet load growth requirements. The B2H project associated increased transmission connectivity between the Northwest and Idaho Power will allow BPA to serve additional demand in Baker City.

Finally, additional transmission capacity can create opportunities for new energy resources, which can add to the county tax base and create new jobs.

GATEWAY WEST PROJECT

Project Background

The Gateway West transmission line project is a joint project between Idaho Power and PAC 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. PAC is currently the project manager for Gateway West, with Idaho Power providing a supporting role.

Figure 5 shows a map of the entire project identifying the authorized routes in the federal permitting process based on the BLM's November 2013 ROD for segments 1 through 7 and 10. Segments 8 and 9 were further considered through a Supplemental EIS by the BLM. The BLM issued a ROD for segments 8 and 9 on January 19, 2017. In March 2017, this ROD was rescinded by the BLM for further consideration. On May 5, 2017, the Morley Nelson Snake River Birds of Prey National Conservation Area Boundary Modification Act of 2017 (H.R. 2104) was enacted. H.R. 2104 authorized the Gateway West route through the Birds of Prey area that was proposed by Idaho Power and PAC and supported by the Idaho Governor's Office, Owyhee County and certain other constituents. On April 18, 2018, the BLM released the Decision Record granting approval of a ROW for Idaho Power's proposed routes for segments 8 and 9.

In its 2017 IRP, PAC announced plans to construct a portion of the Gateway West Transmission Line in Wyoming. PAC has subsequently constructed the 140-mile segment between the planned Aeolus Substation near Medicine Bow, Wyoming, and the Jim Bridger power plant near Point of Rocks, Wyoming. The Aeolus to Bridger/Anticline 500 kV line segment was energized November 2020.

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

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

- Improve transmission grid reliability
- Provide access to abundant renewable energy that will lead to a cleaner generating portfolio across the West

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

The Gateway West

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

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

Figure 5. Gateway West map

Idaho Power Segments

Idaho Power has a one-third 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.

The Gateway West transmission capacity between the Magic Valley and the Treasure Valley areas can relieve two primary transmission constraints: 1) transmission capacity between the Magic Valley and Treasure Valley (Midpoint West), and 2) transmission capacity between the Mountain Home area, and the Treasure Valley (Boise East). These transmission constraints limit the amount of new generation resources that can be sited on the Idaho Power system east of the Treasure Valley area. Planned coal exits from Jim Bridger and North Valmy open up some capacity on the paths that can also be used for new resources, but additional transmission capacity may be required depending on the resource portfolio.

The Midpoint to Hemingway 500 kV line (segment 8) between the Magic Valley and the Treasure Valley was modeled to relieve transmission congestion allowing new IRP resources to be added to the system. The Midpoint to Hemingway segment was modeled as being phased in as two distinct projects described below.

Figure 6. Gateway West map–Magic Valley to Treasure Valley segments (8 and 9)

2021 IRP Gateway West—Phase 1 (Partial Segment 8)

For the 2021 IRP, the company modeled a partial build phase of a Gateway West segment, the Midpoint to Hemingway #2 500 kV line (segment 8) as a possibility. The partial build phase would be a subset of segment 8 constructed between Hemingway and Mountain Home with the line constructed at 500 kV but operated at 230 kV. This Phase 1 partial segment increases the capacity of the Idaho Power transmission system, by approximately 700 MW, between Mountain Home and Boise required to support incremental resources sited to the east.

2021 IRP Gateway West—Phase 2 (Complete Segment 8)

Phase 2 would be to complete the second half of the Gateway West segment 8 project between Midpoint and Mountain Home. The line would be operated at 500 kV from Midpoint to

Hemingway after this phase is constructed. The total capacity provided by the complete segment 8 would increase the transmission capacity into the Treasure Valley by approximately 1,500 MW, which represents an additional 800 MW increase from Phase 1.

Depending on transmission capacity needs, the complete segment 8 could also be built in a single phase.

2021 IRP Gateway West Transmission Assumptions

The siting of new resources, such as wind and solar, on the Idaho Power system are limited by internal transmission constraints on the Idaho Power system between the Magic Valley and the Treasure Valley, in particular the Midpoint West and Boise East internal transmission paths. The 2021 IRP analysis determined the incremental resource additions that would trigger the need for Gateway West to transport energy from new resources to the Treasure Valley load center. Historical resource and load data and transmission service obligations were analyzed to determine the existing transmission commitments and available transmission capacity that could be utilized by new resources. For this determination the company assumed 75th percentile resource levels and 25th percentile system loads in the Magic Valley and Eastern Idaho. Planned unit exits from Valmy and Bridger power plants in the IRP portfolios open up capacity that can be utilized by new resources and are also part of the analysis.

Base with B2H Portfolio Gateway West Transmission Assumptions

As described in the B2H Benefits and Values section of this appendix, the transmission capacity on the Idaho Power operated Borah West and Midpoint West transmission paths will be upgraded to support additional east-to-west schedules and to enable PAC's usage of its B2H capacity. PAC will acquire 600 MW of east-to-west transmission assets across Borah West, Midpoint West, and Boise East for an ownership path to their B2H capacity, and PAC will terminate its existing 510 MW east-to-west transmission service across Idaho Power. Idaho Power can re-purpose the transmission previously reserved for PAC's transmission service for the integration of new resources. Table 14 below details the east-to-west Borah West and Midpoint West ownership, transmission service obligations, and Idaho Power net capacity for use before and after the B2H project.

Table 14. Idaho Power internal path capacity and ownership

	Path Rating E to W	Idaho Power Ownership E to W	PAC Ownership E to W	PAC Transmission Service E to W	Idaho Power Net Capacity E to W
Without B2H					
Boise East	~3700* MW	2610 MW	1090 MW	510 MW	2100 MW
Midpoint West	2800 MW	1710 MW	1090 MW	510 MW	1200 MW
Borah West	2557 MW	1467 MW	1090 MW	510 MW	957 MW
After B2H and Idaho Upgrades					
Boise East	~4250 MW	2560 MW	1690 MW	0 MW	2560 MW
Midpoint West	~3350 MW	1660 MW	1690 MW	0 MW	1660 MW
Borah West	~3180 MW	1490 MW	1690 MW	0 MW	1490 MW

* Rating assumes planned near-term rebuild of an existing 230 kV line.

Per the 2022 Term Sheet, the addition of B2H will come with 200 MW of capacity from Four Corners Substation in New Mexico to Populus Substation in eastern Idaho. Utilization of this capacity will consume some of the east-to-west capacity listed above to move it across southern Idaho to load. Offsetting some of the 200 MW Four Corners schedule will be the addition of BPA southeast Idaho customer network load located east of the paths detailed in Table 8. BPA southeast Idaho load increases the network load on the eastern side of the Idaho Power system and therefore reduces the east-to-west congestion. The net impact of the upgrades, PAC wheeling termination, Four Corners capacity, and BPA southeast Idaho network load, compared to a scenario without B2H and the associated 2022 Term Sheet, results in approximately 400 MW more available east-to-west transmission capacity in B2H portfolios than portfolios without the addition of B2H.

The Base with B2H portfolio includes 700 MW of new wind resources and 1,405 MW of new solar resources. These resources are assumed to be added on the Idaho Power transmission system east of the Treasure Valley. The stand-alone battery resources are assumed to be sited near the Treasure Valley load center, or co-located with the new wind and solar resources, and therefore do not require network transmission across southern Idaho to the Treasure Valley. The net approximate 400 MW of capacity gained by the internal east-to-west upgrades associated with B2H coupled with the exits of Valmy and Bridger allow the Preferred Portfolio (Base with B2H) resources to be integrated without requiring a Gateway West segment.

Base without B2H PAC Bridger Alignment Portfolio Gateway West Transmission Assumptions

The Base without B2H PAC Bridger Alignment portfolio includes 1,200 MW of new wind resources and 1,905 MW of new solar resources. Similar to the Base with B2H portfolio, it is assumed these resources would be sited on the Idaho Power transmission system east of the Treasure Valley and that stand-alone battery resources would be sited near the Treasure Valley load center or co-located with the new wind and solar resources. For this portfolio the upgrades detailed in the Borah West and Midpoint West Capacity Upgrades section, and the Gateway West partial segment 8 (project 1) would be required in 2027 and the Gateway West completed segmented 8 would be required in 2033. The additional amount of wind and solar and the 400 MW net reduction in available transmission capacity compared to the Preferred Portfolio (Base with B2H) necessitates the addition of the Gateway West projects to the portfolio.

SOUTHWEST INTERTIE TRANSMISSION PROJECT-NORTH

The Southwest Intertie Transmission Project-North (SWIP-North) is a proposed 275-mile 500 kV transmission project being developed by Great Basin Transmission, LLC which is an affiliate of LS Power. The SWIP-North connects Idaho Power's Midpoint Substation near Twin Falls, Idaho, and the Robinson Summit Substation near Ely, Nevada. The project would provide a connection to the One Nevada 500 kV Line (ON Line) which is an in-service segment between Robinson Summit and the Harry Allen Substation in the Las Vegas, Nevada, area. The two projects together are the combined SWIP project. The combined SWIP project is expected to have a bi-directional WECC-approved path rating of approximately 2,000 MW.

Figure 7. SWIP-North preliminary route

The addition of the SWIP-North segment would unlock additional capacity on the existing ON Line that connects northern and southern Nevada. Contractual ownership of capacity on SWIP-North would provide capacity rights to and from the Harry Allen Substation in the Las Vegas area. The Harry Allen Substation is connected to CAISO via the newly constructed DesertLink 500 kV line. The substation is also near the Desert Southwest market hub, Mead. Idaho Power's potential participation in the project could provide the company transmission access—past transmission congestion on NV Energy's system—from the Desert Southwest market and CAISO directly to Idaho Power. Figure 7 shows the SWIP-North Preliminary Route and the locations of the ON Line and DesertLink 500 kV lines to the south.

To determine a cost-estimate for SWIP-North, the company used publicly available cost data for similar lines recently constructed in Nevada and assumed that Idaho Power would own a 200-MW share of the south-to-north capacity.

Total Cost Estimate (200 MW share): $133 million with a pre-summer 2025 in-service date.

COMBINED MAJOR TRANSMISSION PROJECTS IN IDAHO

B2H, Gateway West, and SWIP North, when combined, can provide vast interregional connectivity for both load and resource diversity. Figure 8 below depicts the opportunity the combination of these projects can provide to Idaho Power, and the greater Western Interconnection.

Figure 8. Map of B2H, Gateway West, and SWIP North

2021 IRP PORTFOLIO TRANSMISSION COST ASSUMPTIONS

The transmission assumptions from the 2021 IRP Preferred Portfolio (Base with B2H) are listed in Table 15. The Base with B2H portfolio includes the 2026 addition of the B2H project including the Midline Series Capacitor Station, the 230 kV Hemingway Integration Projects, and Borah West and Midpoint West Upgrades to support increased east-to-west flows for PAC and Idaho Power. The capital costs in the table include Idaho Power AFUDC and 0% contingency.

Table 15. Preferred Portfolio (Base with B2H) transmission upgrades and capital costs

Upgrade	Year	Capital Costs
B2H (45.45% IPC Share)	2026	$425.2M
B2H Midline Series Capacitor Station (45.45% IPC Share)	2026	$10.3M
230 kV Hemingway Integration Projects	2026	$35.3M
Borah West and Midpoint West Upgrades*	2026	$46.8M

*Upgrades to jointly owned Idaho Power and PAC assets.

The transmission assumptions for the Base without B2H PAC Bridger Alignment portfolio (the least cost portfolio that did not include B2H) are listed in Table 16. This portfolio contains Gateway West phases in 2027 and 2033 to enable higher amounts of solar and wind resource additions to the system east of the Treasure Valley. The Gateway West projects deliver energy to Hemingway necessitating a larger connection between Hemingway and the Treasure Valley load area; consequently, the 230 kV Hemingway Integration Projects are also a required upgrade in this portfolio. Further, the Borah West and Midpoint West Upgrades are included in this portfolio as they are the initial lowest cost upgrades on the existing system. Absent any future agreement, PAC is assumed to participate in the upgrades at the existing Borah West and Midpoint West joint ownership percentages. This reduces the cost and capacity gained by Idaho Power from the upgrades. Again, the capital costs in the table include Idaho Power AFUDC and 0% contingency.

Table 16. Base without B2H PAC Bridger alignment transmission upgrades and capital costs

Upgrade	Year	Capital Cost
Gateway West Phase 1 (Partial Segment 8)	2027	$176.1M
230 kV Hemingway Integration Projects	2027	$35.3M
Borah West and Midpoint West Upgrades*	2027	$16.2M
Gateway West Phase 2 (Complete Segment 8)	2033	$176.1M

*Upgrades to jointly owned Idaho Power and PAC assets.

Transmission Line Estimates

Idaho Power has contracted with HDR to serve as the B2H project's third-party owners' engineer and prepare the B2H transmission line cost estimate. HDR has extensive industry experience, including experience serving as an owner's engineer for BPA for the last seven years. HDR has prepared a preliminary transmission line design that locates every tower and access road needed for the project. HDR used utility industry experience and current market values for materials, equipment, and labor to arrive at the B2H estimate. Material quantities and construction methods are well understood because the B2H project is utilizing BPA's standard tower and conductor design for 500 kV lines. BPA has used the proposed towers and conductor on hundreds of miles of lines currently in-service. HDR was the owner's engineer on recent BPA projects, so HDR is also familiar with the BPA towers and conductor the B2H project is using.

Substation Estimates

The northern terminus for B2H requires a new substation near Boardman, Oregon, to tap into the existing BPA 500 kV transmission network. BPA owns the land for the Longhorn Station and must complete all NEPA reviews and other legal requirements before making a final decision to construct Longhorn Station. BPA proposed the Longhorn Station to integrate certain wind projects in the immediate area. BPA has prepared the Longhorn Station cost estimate, based on its extensive experience designing and constructing substations.

The southern terminus for B2H is Idaho Power's Hemingway Substation, near Murphy, Idaho. The Hemingway Substation has an existing 500 kV connection between Idaho Power's Midpoint Substation (near Shoshone, Idaho) and PAC's Summer Lake Substation in Lake County, Oregon. Completed in 2013, the Hemingway Substation is designed to accommodate the B2H line terminal in the future. New equipment must be ordered and installed, but no station expansion will be required. Based on these expectations, Idaho Power prepared the Hemingway Substation cost estimate.

Calibration of Cost Estimates

The B2H estimate was reviewed and approved by BPA and PAC. BPA and PAC both have recent transmission line construction projects to calibrate against. The recent projects included the following:

- BPA: Lower Monumental–Central Ferry 500 kV line (38 miles, in-service 2015)
- BPA: Big Eddy–Knight 500 kV line (39 miles, in-service 2016)
- PAC: Sigurd to Red Butte 345 kV line (160 miles, in-service 2015)
- PAC: Mona to Oquirrh 500 kV line (100 miles, in-service 2013)

Additionally, in early 2017 Idaho Power visited with NV Energy and Southern California Edison to learn from each company's recent experience constructing 500 kV transmission lines in the

West. As part of the discussions with each company, Idaho Power calibrated cost estimates and resource requirements.

The two projects were as follows:

- NV Energy: ON Line project (235 miles, 500 kV, in-service 2014)
- Southern California Edison: Devers to Palo Verde (150 miles, 500 kV, in-service 2013)

Costs Incurred to Date

Approximately $125 million, including AFUDC, has been expended on the B2H project through December 31, 2021. The $125 million incurred through December 31, 2021, is included in the $1 to $1.2 billion total estimate. Idaho Power's share of the costs incurred to-date is included in B2H IRP portfolio modeling.

Additional Costs Applied to B2H

In addition to the base costs of the B2H project, the company also applied additional costs to the B2H project in the 2021 IRP modeling. These costs have been previously discussed in this appendix and are: 1) costs for local interconnection upgrades totaling approximately $35 million, and 2) costs for Borah West and Midpoint West upgrades necessary to facilitate the PAC asset exchange, detailed in the 2022 Term Sheet and B2H Project Partner Update section of this appendix, totaling approximately $47 million.

Cost-Estimate Conclusions

The cost estimate for B2H has been thoroughly vetted. Idaho Power used third-party contractors with industry experience, relied on PAC and BPA recent transmission line construction experience, and benchmarked against multiple recent high-voltage transmission line investments in the West to arrive at the B2H construction cost estimate. Material quantities and construction methods are well understood because the B2H project is using BPA's standard tower and conductor design for 500 kV lines. The cost estimate for the project will be further refined as the project design develops toward completion.

Transmission Revenue

The B2H transmission line project is modeled in AURORA as additional transmission capacity available for Idaho Power energy purchases from the Pacific Northwest. In general, for new supply-side resources modeled in the IRP process, surplus sales of generation are included as a cost offset in the AURORA portfolio modeling. Transmission wheeling revenues, however, are not included in AURORA calculations. To remedy this inconsistency, in the 2021 IRP, Idaho Power modeled incremental transmission wheeling revenue from non-native load customers as an annual revenue credit for B2H portfolios, representing a reduction in project costs and ultimately benefiting Idaho Power retail customers.

Idaho Power's transmission assets are funded by native load customers, network customers, and point-to-point transmission wheeling customers based on a ratio of each party's usage of the transmission system. For the 2021 IRP, Idaho Power modeled B2H assuming the company has a 45% ownership interest and is providing transmission service to BPA, with BPA transmission wheeling payments acting as a cost-offset to the overall B2H project costs. Idaho Power also modeled the change in PAC point-to-point usage. Portfolios involving B2H result in a higher FERC transmission rate than portfolios without B2H. Although B2H provides significant incremental capacity, and will likely result in increased transmission sales, Idaho Power assumed flat short-term and non-firm transmission sales volume as a conservative assumption.

Idaho Power's FERC transmission rate is calculated as follows:

$$Transmission\ Rate = \frac{Transmission\ Costs\ (\$)}{Transmission\ Usage\ (MW * year)}$$

Per the formula above, transmission costs will increase following the installation of B2H, and transmission usage will adjust with the company providing increased transmission service associated with additional BPA network load, and reduced transmission service corresponding to PAC's net point-to-point usage declining. To calculate the B2H cost offset annual revenue stream, the company calculated the difference between two scenarios:

1. The B2H third-party transmission revenues it would receive assuming the 2021 IRP Preferred Portfolio; and
2. the third-party transmission revenues it would receive in a case without the addition of B2H assuming PAC continues to utilize 510 MW of point-to-point service, and BPA finds an alternative long-term plan for serving its customers in southeast Idaho (B2H is currently the plan that they are pursuing).

The difference between these two scenarios represents the B2H cost offset annual revenue stream that was applied as a reduction to B2H overall costs.

Due to significant increase in capacity that B2H provides to the Idaho to Northwest path, Idaho Power believes firm, short-term firm, and non-firm usage of the Idaho Power transmission system by third parties could increase. This belief is supported by the over 1,000 MWs of transmission requests that the company has seen across the Idaho to Northwest path over the past 18 months. Additionally, Idaho Power's acquisition of 200 MW of bidirectional capacity to Four Corners, New Mexico will only further enhance the value of the company transmission system to third parties. These potential revenues would further reduce the cost of the project, however, to be conservative, Idaho Power assumed a constant transmission usage by third parties (no increase or decrease) from an average of usage over recent years.

RISK

Risk is inherent in any infrastructure development project. The sections below address various risks associated with the B2H project. Combining the analysis below with the risk analysis conducted in the 2021 IRP, B2H is the lowest-risk resource to meet Idaho Power's resource needs.

Capacity, Cost, and In-Service Date Risk

The company evaluated the following risks extensively in the 2021 IRP:

- **Capacity Risk:** As part of the 2021 IRP, the company looked at portfolio costs assuming the company can access 350 MW, 400 MW, 450 MW, 500 MW (the Preferred Portfolio), and 550 MW of capacity.
- **Cost Risk:** Evaluating cost risks to ensure cost-effectiveness (i.e., a tipping point analysis) is an important consideration when planning for a project.
- **In-Service Date Risk:** The current planned in-service date for B2H is prior to the summer of 2026. The company evaluated the impacts of a 2027 in-service date.

A description of each of these risks can be found in the 2021 IRP Chapter 10—Modeling Analysis and Results, starting on page 144 of the document.

Regarding cost risk, the 2021 IRP portfolio Net Present Value (NPV) cost for B2H is approximately $160 million (this is the NPV cost incurred within the 20-year planning window) assuming a 0% contingency amount. The difference between the Preferred Portfolio, and the best alternative portfolio that did not include B2H was approximately a $266 million NPV. Therefore, B2H costs could increase by nearly 165% and the project would remain cost effective.

Liquidity and Market Sufficiency Risk

This risk was partially addressed by the capacity risk evaluation detailed starting on page 144 of the 2021 IRP. As part of the 2021 IRP, the company looked at portfolio costs assuming the company can access 350 MW, 400 MW, 450 MW, 500 MW (the Preferred Portfolio), and 550 MW of capacity. Of note, should market capacity ever become limited, this will not reduce B2H's capacity. The company would have the flexibility to acquire or develop another resource in the Pacific Northwest, potentially in eastern Oregon, and repurpose B2H transmission capacity to continue to meet its customers' needs. As discussed in the Flexibility section of this appendix, a transmission line like B2H will facilitate the transfer of any generation technology, ensuring Idaho Power customers always have access to the most economic resources, regardless of the resource type.

Focusing on the market, the Pacific Northwest is a winter peaking region. Pacific Northwest utilities continue to install and build generation capacity to meet winter peak regional needs. Idaho Power operates a system with a summer peak. Idaho Power's peak typically occurs in the late June/early July timeframe. The Idaho Power summer peak aligns with the Mid-C hydro runoff conditions when the Pacific Northwest is flush with surplus power capacity. The existing transmission system between the Pacific Northwest and Idaho Power is constrained. Constructing B2H will alleviate this constraint and add 1,050 MW of total transfer capability between the Pacific Northwest and the Intermountain West region. The Pacific Northwest and Idaho Power will significantly benefit from the addition of transmission capacity between the regions. The Pacific Northwest has constructed power plants to meet winter needs and would benefit from selling energy to Idaho Power in the summer. Idaho Power needs generation capacity to serve summer peak load, and a transmission line to existing underutilized power plants is much more cost-effective than building a new power plant.

See the Market Overview section of this appendix for more information about the Mid-C market hub liquidity. Based on the risk assessment, Idaho Power believes sufficient market liquidity exists.

The following data points will address the market sufficiency risk.

Data Point 1: Peak Load Analysis from Table 8

Referencing Table 8 from the B2H Benefits and Values section, British Columbia and other utilities in the Pacific Northwest[18] have forecast 2030 winter peaks that exceed their forecast 2030 summer peaks by a combined 8,200 MW. Given the difference in seasonal peaks, coupled with Columbia runoff hydro conditions aligning with Idaho Power's summer peak, resource availability in the Pacific Northwest during Idaho Power's summer peak is highly likely.

Data Point 2: 2019 Pacific Northwest Loads and Resources Study—BPA

Idaho Power's review of recent regional resource adequacy assessments also included the *Pacific Northwest Loads and Resources Study* by the BPA (White Book). The most recent BPA adequacy assessment report was released October 2020 and evaluates resource adequacy from 2021 through 2030.[19] Idaho Power concludes from this analysis that: 1) summer capacity will be available in the future, and 2) additional summer capacity will likely be added as the region

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[18] Load serving entities from Table 8 included in stated figure are Avista, BPA, British Columbia, Chelan, Douglas, Grant, PAC–West, Portland General, Puget Sound, Seattle City, and Tacoma.

[19] BPA. 2019 Pacific Northwest loads and resources study (2019 white book). Technical Appendix, Volume 2: Capacity Analysis. bpa.gov/p/Generation/White-Book/wb/2019-WBK-Technical-Appendix-Volume-2-Capacity-Analysis.pdf . Accessed November 24, 2021.

adds resources to meet winter peak demand. BPA considers regional load diversity (i.e., winter- or summer-peaking utilities) and expected monthly production from the Pacific Northwest hydroelectric system under the critical case water year for the region (1937). Canadian resources are excluded from the BPA assessment. New regional generating projects are included when those resources begin operating or are under construction and have a scheduled on-line date. Similarly, retiring resources are removed on the date of the announced retirement. Resource forecasts for the region assume the retirement of the following coal projects over the study period:

Table 17. Coal retirement forecast

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

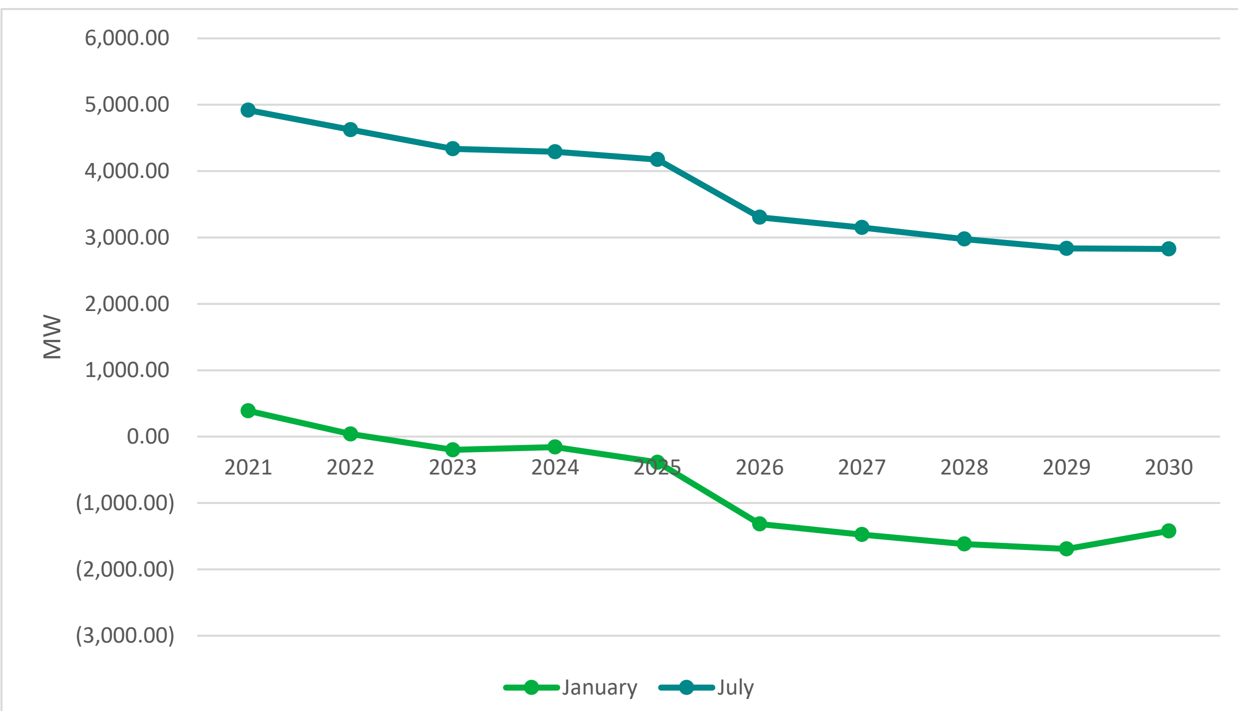

Figure 9. BPA white book PNW surplus/deficit one-hour capacity (1937 critical water year)

Data Point 3: FERC Form 714 Load Data

For illustrative purposes, Idaho Power downloaded peak load data reported through FERC Form 714 for the major Pacific Northwest entities in Washington and Oregon: Avista, BPA, Chelan County PUD, Douglas County PUD, Eugene Water and Electric Board, Grant County PUD, PGE, Puget Sound Energy, Seattle City Light, and Tacoma (PAC West data was unavailable). The coincident sum of these entities' total load is shown in Figure 10.

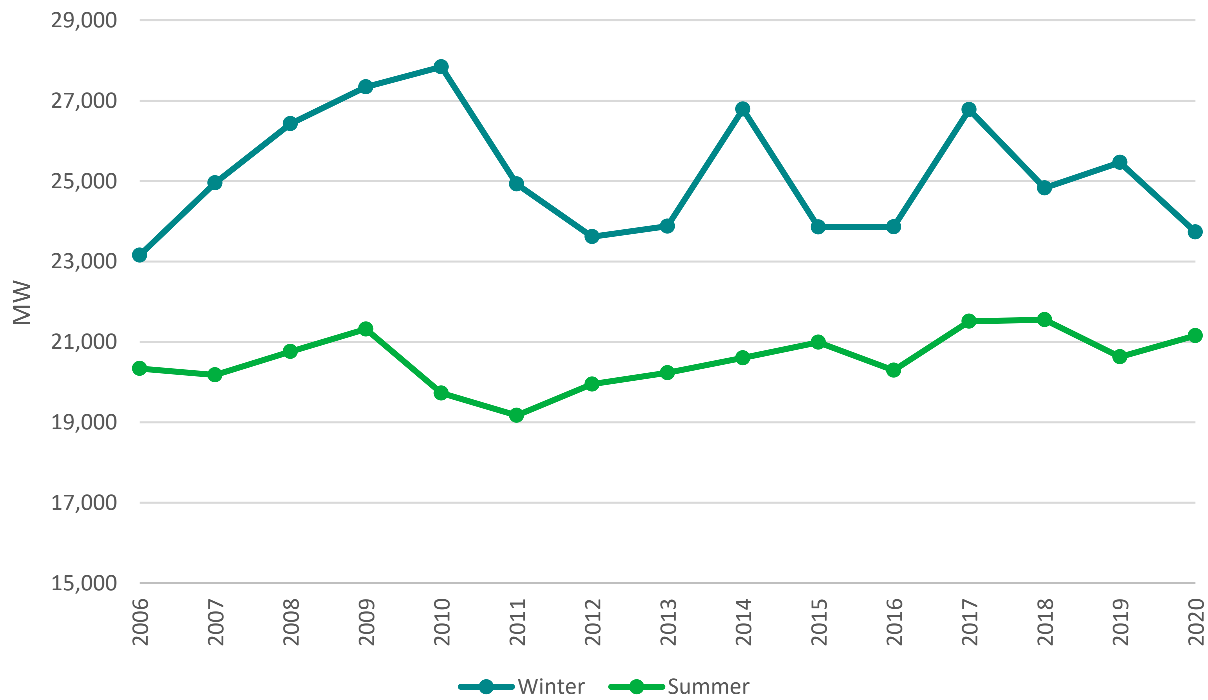

Figure 10. Peak coincident load data for most major Washington and Oregon utilities

Figure 10 illustrates a wide difference between historical winter and summer peaks for the Washington and Oregon area in the region. Other considerations, not depicted, include Canada's similar winter- to summer-peak load ratio (winter peaking), and the increased ability of the Pacific Northwest hydro system in late June through early July compared to the hydro system's capability in the winter (more water in early summer compared to winter).

Data Point 4: Northwest and California Renewable Portfolio Standards

The adoption of more aggressive Renewable Portfolio Standard (RPS) goals by states such as California, Oregon, and Washington will drive policy-driven resource additions. The RPS goals will also likely result in more solar generation throughout the region and additional dispatchable flexible ramping resources, such as battery storage. Solar and solar plus storage align very well with summer peak needs, but their value can be limited in the winter months. Meeting winter needs will require the Pacific Northwest region to overbuild these resources above the level to meet a similar a summer demand, which will continue to align well with Idaho Power looking to access summer energy from the market.

Data Point 5: Potential Resources from Northwest Utility IRPs

The 2021 PNUCC Northwest Regional Forecast includes a list of potential new resources reported by northwest utilities in their integrated resource plans to meet their own needs. The forecasted new resource list from the report is shown in Table 18. The list of resources includes 6,389 MW of planned new resources through 2031. As expected, the NW utilities are continuing to plan for growing winter peak demands by adding capacity resources. Many of these resource additions, such as solar and storage installations, will have a much higher Effective Load Carrying Capability (ELCC) for the summer season, furthering the depth of the market for the summer season.

Table 18. Potential New Resources Identified by Regional Utilities (PNUCC)*

Project	Year	Fuel/Tech	Nameplate (MW)	Utility
Kettle Falls upgrade	2026	Biomass	12	Avista
NW hydro slice	2031	Contract	75	Avista
Natural gas peaker	2027	Gas	85	Avista
Natural gas peaker	2027	Gas	126	Avista
Montana wind	2023	Wind	100	Avista
Montana wind	2024	Wind	100	Avista
Montana wind	2028	Wind	100	Avista
Cleanera Apex I	2021	Solar	80	NorthWestern Energy
Grizzly Wind	2021	Wind	79	NorthWestern Energy
Black Bear Wind	2021	Wind	79	NorthWestern Energy
ConEd Wheatland	2022	Wind	75	NorthWestern Energy
ConEd Pondera	2022	Wind	20	NorthWestern Energy
ConEd Teton	2022	Wind	19	NorthWestern Energy
Caithness Beaver Creek II	2021	Wind w. battery	60	NorthWestern Energy
Caithness Beaver Creek III	2021	Wind w. battery	60	NorthWestern Energy
MTSUN	TBD	Solar	80	NorthWestern Energy
Battery	2028	Battery	180	PacifiCorp
Battery	2029	Battery	435	PacifiCorp
Solar w. battery	2024	Solar w. battery	1,249	PacifiCorp
Solar w. battery	2029	Solar w. battery	359	PacifiCorp
Wind w. battery	2029	Wind w. battery	10	PacifiCorp
Non spec. capacity	2024	Capacity	237	Portland General Electric
Non spec. capacity	2026	Capacity	39	Portland General Electric
Non spec. capacity	2027	Capacity	76	Portland General Electric
Non spec. capacity	2028	Capacity	130	Portland General Electric
Non spec. capacity	2029	Capacity	213	Portland General Electric
Non spec. capacity	2030	Capacity	254	Portland General Electric
Non spec. renewable	2024	Renewable	362	Portland General Electric
Non spec. renewable	2025	Renewable	233	Portland General Electric
Non spec. renewable	2029	Renewable	67	Portland General Electric
Battery	2022-2025	Battery	75	Puget Sound Energy
Battery	2026-2030	Battery	125	Puget Sound Energy
Flexible capacity	2026-2030	Capacity	237	Puget Sound Energy
Non spec. renewable	2022-2025	Renewable	600	Puget Sound Energy
Non spec. renewable	2026-2030	Renewable	1,100	Puget Sound Energy
Solar	2022-2025	Solar	80	Puget Sound Energy
Solar	2026-2030	Solar	150	Puget Sound Energy
Capacity product	2020-2024	Contract	25	Snohomish County PUD
Dispatchable capacity	2028	Capacity	120	Snohomish County PUD
Total (Nameplate)			**6,389**	

*PNUCC-2021-Northwest-Regional-Forecast-Final.pdf

Market Sufficiency and Liquidity Conclusions

The analysis summarized above and in the Markets section of this report provide strong evidence that there will be sufficient resources in the future to utilize the B2H transmission line.

Siting Risk

Any new infrastructure projects, from generation projects to transmission lines, comes with siting risk. The BLM ROD, which was released on November 17, 2017, was a significant milestone in the B2H project development and greatly minimized siting risk by authorizing the project on 85.6 miles of BLM-administered land. The United States Forest Service also issued a ROD authorizing the project on 8.6 miles of National Forest land in 2018, and the United States Navy issued a ROD in 2019 authorizing the project on 7.1 miles of Navy land. The BLM and Forest Service RODs were upheld by the United States District Court for the District of Oregon.[20]

The issuance of a site certificate by the Oregon EFSC is the next major step in the siting process. In 2020, ODOE issued its Proposed Order recommending approval of the project. That Proposed Order, however, is being challenged by third-parties in an ongoing Contested Case proceeding and will ultimately be subject to review and approval by EFSC, and the EFSC's decision will be subject to appeal before the Oregon Supreme Court. Until EFSC makes its final decision on the Site Certificate, which Idaho Power expects by the end of 2022, and any appeal is resolved, there remains some siting risk.

Schedule Risk

As of the date of this appendix, Idaho Power's scheduled B2H in-service date is 2026 or later. At a high level, remaining activities prior to energization are: permitting, preliminary construction, material procurement, and construction.

As noted above, the permitting phase of the project is ongoing. For federal permitting, the B2H project achieved the biggest schedule milestone to date with the release of BLM's ROD on November 17, 2017, and subsequent ROW grant in January 2018 authorizing the project on BLM-administered lands. The United States Forest Service ROD was issued in November 2018 and a right-of-way easement was issued in May 2019. A Navy ROD was issued in September 2019 and a Navy easement was issued in May 2020. The project is on track to receive the federal notice to proceed in 2023.

For the State of Oregon permitting process, the B2H project also achieved a considerable milestone in summer 2017 with the submittal of the Amended Application for Site Certificate to

[20] Stop B2H Coalition v. Bureau of Land Management, No. 2:19-cv-1822-SI, Order and Opinion (D. Or. August 4, 2021).

the ODOE and an application completeness determination from ODOE in fall 2018. ODOE issued a Proposed Order in July 2020, and EFSC is expected to issue its decision on the Site Certificate in 2022. The EFSC permitting process is a critical path schedule activity. Schedule risk exists for the EFSC permitting process if the EFSC does not issue a Site Certificate in 2022.

With the receipt of the BLM ROD and ROW easement, and a Proposed Order from ODOE, sufficient route certainty exists to continue with preliminary construction tasks. At the time of writing, Idaho Power is actively working on the following activities: detailed design, ROW option acquisition, legal surveys, and geotechnical investigation. Construction activities are expected to commence in 2023 with the expected project in-service date in 2026.

Catastrophic Event Risk

As detailed in B2H Design section of this appendix, the B2H transmission line is designed to withstand a variety of extreme weather conditions and catastrophic events. Like most infrastructure, the B2H project is susceptible to direct physical attack. However, unlike some other supply-side resources, B2H adds to the resiliency of the electrical grid by providing additional capacity and an additional path to transfer energy throughout the region should a physical attack or other catastrophic event occur elsewhere on the system.
Additionally, Idaho Power also keeps a supply of emergency transmission towers that can be quickly deployed to replace a damaged tower, allowing the transmission line to be quickly returned to service.

PROJECT ACTIVITIES

Schedule Update

Permitting

The B2H projected achieved a major milestone with the release of the BLM ROD on November 17, 2017, and the ROW grant on January 9, 2018. These actions formalized the conclusion of the siting process and federally required NEPA process. The BLM ROD and ROW grant provides the B2H project the ability to site the project on BLM-administered land. The BLM-led NEPA process took nearly 10 years to complete and involved extensive stakeholder input. Refer to the Project History and Route History sections of this report for more information on project history and public involvement. With the issuance of the United States Forest Service ROD and easement, and the issuance of the United States Navy ROD, all major federal decision records have been achieved.

For the State of Oregon permitting process, Idaho Power submitted the Amended Application for Site Certificate to the ODOE in summer 2017 and ODOE issued a Proposed Order in July 2020. A decision on the Site Certificate from the EFSC is expected in 2022.

The NEPA and EFSC processes are separate and distinct permitting processes and not necessarily designed to work simultaneously. At a high level, the NEPA EIS process evaluates reasonable alternatives to determine the best alternative (the Agency Preferred Alternative) at the end of the process. Comparative analysis is conducted at a "desktop" level. Information is brought into the process on a phased approach. Detailed analysis must be conducted on the final route prior to construction, generally once final design is complete.

The Oregon EFSC process is a standards-based process based on a fixed site boundary. For a linear facility, like a transmission line, the process requires the transmission line boundary to be established (a route selected) and fully evaluated to determine if the project meets established standards. The practical effect of the EFSC standards-based process required the NEPA process be far enough along to conduct field studies and other technical analyses to comply with standards. Idaho Power conducted field surveys and prepared the EFSC application in parallel with the NEPA process. The EFSC application is lengthy, coming in at over 20,000 pages.

Post-Permitting

To achieve an in-service date in 2026, preliminary construction activities have commenced parallel to EFSC permitting activities. Preliminary construction activities include, but are not limited to, the following:

- Geotechnical explorations
- Detailed ground surveys

- LiDAR aerial mapping
- Sectional surveys
- ROW option acquisition activities
- Detailed design
- Construction bid package development and construction contractor selection

After the Oregon permitting process and preliminary construction activities conclude, construction activities can commence. Construction activities include, but are not limited to, long-lead material acquisition, transmission line construction, and substation construction. The preliminary construction activities must commence several years prior to construction. The material acquisition and construction activities are expected to take approximately 3 years. The specific timing of each of the preliminary construction and construction activities will be coordinated with the project coparticipants.

CONCLUSION

As the B2H project nears its construction phase, the 2021 IRP shows that the B2H project remains a key component of the company's Preferred Portfolio of future resources. Additionally, project certainty continues to grow with Idaho Power, PAC, and BPA executing a 2022 Term Sheet related to the B2H project on January 18, 2022. The parties entered this 2022 Term Sheet after jointly funding the permitting of the B2H project over the past decade and over two years of discussions related to next steps associated with the B2H project.

As part of the 2022 Term Sheet, BPA will transition out of its role as a joint B2H permitting coparticipant and will instead take transmission service from Idaho Power to serve its southeast Idaho customers. Idaho Power will increase its B2H ownership to 45.45% by acquiring BPA's B2H capacity. Idaho Power's B2H capacity will increase from an average of 350 MW west-to-east to 750 MW west-to-east, and Idaho Power will utilize a portion of its increased B2H capacity to provide BPA transmission service across southern Idaho.

As part of the larger transaction, Idaho Power and PAC also plan to complete an asset exchange to align transmission ownership with each party's long-term strategy. Idaho Power will acquire PAC transmission assets and their related capacity sufficient to enable Idaho Power to utilize 200 MW of bidirectional transmission capacity between the Idaho Power system (Populus) and Four Corners Substation in New Mexico. Idaho Power will also acquire PAC assets around the Goshen area necessary to provide transmission service to BPA to serve their southeast Idaho customers. Idaho Power will be relieved of its 510 MW of transmission service obligations to PAC across southern Idaho, freeing up capacity the company plans to utilize to integrate additional southern Idaho renewable resources.

This B2H 2021 IRP appendix provides context and details that support evaluating the B2H transmission line project as a supply-side resource, explores many of the ancillary benefits offered by the transmission line, and considers the risks and benefits of owning a transmission line connected to a market hub in contrast to direct ownership of a traditional generation resource.

As discussed in this report, once operational, B2H will provide Idaho Power increased access to reliable, clean, low-cost market energy purchases from the Pacific Northwest. B2H (including early identification of need that ultimately became the project) has been a cost-effective resource identified in each of Idaho Power's IRPs since 2006 and continues to be a cornerstone of Idaho Power's 2021 IRP Preferred Portfolio.

The B2H project brings additional benefits beyond cost-effectiveness. The B2H project will increase the efficiency, reliability, and resiliency of the electric system by creating an additional pathway for energy to move between major load centers in the West. The B2H project also provides the flexibility to integrate renewable energy and move existing resources during times of congestion, benefiting customers throughout the region. Idaho Power believes B2H provides value to the system beyond any individual resource because it enhances the flexibility of the existing system and facilitates the delivery of cost-effective resources not only to Idaho Power customers, but also to customers throughout the Pacific Northwest and Mountain West regions.

The company must demonstrate a need for the project before EFSC will issue a Site Certificate authorizing the construction of a transmission line. Pursuant to EFSC's least-cost plan rule, the need demonstration can be met through a commission acknowledgement of the resource in the company's IRP.[21] The OPUC has already acknowledged the construction of B2H in Idaho Power's 2017 and 2019 IRPs. Idaho Power asks the OPUC to confirm its acknowledgement of B2H in the company's 2021 IRP.

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

Appendix D-1. Transmission line alternatives to the proposed B2H 500 kV transmission line

Table D-1

Comparison of Transmission Line Capacity Scenarios—New Lines from Longhorn to Hemingway

Scenario	Line Capacity[1]	Potential Path 14 West-East Increase[2]	Losses on New Circuit(s)[3]
a. Longhorn to Hemingway 230 kV single circuit	956 MW	525 MW	10.8%
b. Longhorn to Hemingway 230 kV double circuit	1,912 MW	915 MW	9.5%
c. Longhorn to Hemingway 345 kV single circuit	1,434 MW	730 MW	6.6%
d. Longhorn to Hemingway 500 kV single circuit	3,214 MW	1,050 MW	4.2%
e. Longhorn to Hemingway 500 kV—two separate lines	6,428 MW	2,215 MW	3.7%
f. Longhorn to Hemingway 500 kV double circuit	6,428 MW	1,235 MW	2.9%
g. Longhorn to Hemingway 765 kV single circuit	4,770 MW	1,200 MW	2.4%

[1] Line Capacity is the thermal rating of the assumed conductors and does not account for system limitations of voltage, stability, or reliability requirements.

[2] Potential Rating is based upon study results to date to meet reliability design requirements for the WECC ratings processes, not including simultaneous interaction studies.

[3] Estimated Losses are percent losses for the new line at the Potential Rating loading level. Annual energy losses are dependent on total system loss reductions. All of the scenarios would likely yield a total system loss reduction for the flow levels above.

Table D-2

Comparison of Transmission Line Capacity Scenarios—Rebuild Existing Lines to the Northwest

Scenario	Line Capacity[1]	Potential Path 14 Increase[2]	Losses on New Circuit(s)[3]	Length of Line/ New ROW[4]
h. Replace Oxbow-Lolo 230 kV with Hatwai–Hemingway 500 kV	3,214 MW	430 MW W-E 675 MW E-W	3.8%	255 Miles/136 Miles
i. Replace Oxbow-Lolo 230 kV with Hatwai–Hemingway 500 kV—No double circuiting with existing lines	3,214 MW	710 MW W-E 745 MW E-W	4.1%	255 Miles/167 Miles
j. Replace Walla Walla to Brownlee 230 kV with Sacajawea Tap–Hemingway 500 kV	3,214 MW	400 MW W-E 675 MW E-W	3.5%	288 Miles/150 Miles
k. Replace Walla Walla to Pallette 230 kV with Sacajawea Tap–Hemingway 500 kV—No double circuiting with existing lines	3,214 MW	720 MW W-E 730 MW E-W	3.8%	288 Miles/181 Miles
l. Build double circuit 500 kV/230 kV line from McNary to Quartz. Build 500kV from Quartz to Hemingway.	3,214 MW	765 MW W-E 870 MW E-W	3.9%	298 Miles/168 Miles

[1] Line Capacity is the thermal rating of the assumed conductors and does not account for system limitations of voltage, stability, or reliability requirements.

[2] Potential Rating is based upon study results to date to meet reliability design requirements for the WECC ratings processes, not including simultaneous interaction studies.

[3] Estimated Losses are percent losses for the new line at the Potential Rating west-east loading level. Annual energy losses are dependent on total system loss reductions. All of the scenarios would likely yield a total system loss reduction for the flow levels above.

[4] In addition to utilizing existing 230 kV right-of-way ("ROW"), each of the scenarios above will require new ROW to be obtained.

Appendix D-2. B2H project history, public participation, project activities, route history, and a detailed list of notable project milestones

B2H Project History

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

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

At the beginning of 2022, Idaho Power, PAC, and BPA executed a Non-Binding Term Sheet (2022 Term Sheet) that addresses B2H ownership, transmission service considerations, and asset exchanges. As part of the 2022 Term Sheet, BPA will transition out of its role as a joint B2H permitting partner and will instead take transmission service from Idaho Power to serve its customers. Idaho Power will increase its B2H ownership to 45.45% by acquiring BPA's B2H capacity and will utilize a portion of this increased capacity to provide BPA transmission service across southern Idaho.

In the 2021 IRP, Idaho Power modeled B2H assuming the 2022 Term Sheet specified 45.45% project ownership share.

B2H Public Participation

The B2H project development has involved considerable stakeholder interaction since its inception. Idaho Power has hosted and participated in almost 300 public and stakeholder meetings with an estimated 4,500+ participants. After approximately a year of public scoping in 2008, Idaho Power paused the federal and state review process and initiated a year-long comprehensive public process to gather more input. This community advisory process (CAP) took place in 2009 and 2010. The four objectives and steps of the CAP were as follows:

1. Identify community issues and concerns.
2. Develop a range of possible routes that address community issues and concerns.
3. Recommend proposed and alternate routes.
4. Follow through with communities during the federal and state review processes.

Through the CAP, Idaho Power hosted 27 Project Advisory Team meetings, 15 public meetings, and 7 special topic meetings. In all, nearly 1,000 people were involved in the CAP, either through Project Advisory Team activities or public meetings.

Ultimately, the route recommendation from the CAP was the route Idaho Power brought into the NEPA process as the proponent-recommended route. The NEPA process included additional opportunities for public comment at major milestones, and Idaho Power worked with landowners and communities along the way. Ultimately, the route selected through the NEPA process was based on the BLM's analysis and public input. For more information, please visit the B2H website.

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

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

Unfortunately, the route preferences of Idaho Power and the local communities aren't always reflected in the BLM's Agency Preferred route. For example, Idaho Power had worked in the Baker County area to propose a route on the backside of the NHOTIC (to the east) to minimize visual impacts, and in the Brogan area, to avoid landowner impacts. However, both route variations went through priority sage grouse habitat and were not adopted in BLM's Agency Preferred route.

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

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

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

Idaho Power continued support of the community-favored routes in its Application for Site Certificate filed with ODOE in September 2018. Idaho Power will work with Union County and local stakeholders to determine the route preference between the Morgan Lake and Mill Creek alternatives. As of the date of the filing of the 2021 IRP, Idaho Power understands that the

Morgan Lake route alternative, on balance, appears to be preferred by the majority of the groups previously identified.

Project Activities

Below is a summary of notable activities by year since project inception.

2006

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

2007

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

2008

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

2009

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

2010

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

2011

Additional public outreach resulted in additional route alternatives submitted to the BLM. The Obama Administration recognizes B2H as one of seven national priority projects.[22]

[22] obamawhitehouse.archives.gov/administration/eop/ceq/initiatives/interagency-rapid-response-team-for-transmission

2012

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

2013

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

2014

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

2015

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

2016

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

2017

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

2018

ODOE and Idaho Power conduct public meetings after ODOE determined the Application for Site Certificate was complete. The Oregon PUC issues Order No. 18-176 in Docket No. LC 68 specifically acknowledging Idaho Power's 2017 IRP and action items related to B2H. The United States Forest Service issues its ROD. Idaho Power prepares and submits a Geotechnical Plan of Development to the BLM for approval.

2019

The United States Forest Service issues right-of-way (ROW) easement. ODOE issues a Draft Proposed Order (DPO). The United States Navy issues its ROD. BPA issues a ROD for moving the existing 69 kV line from Navy property to accommodate B2H. Idaho Power coordinates with BLM on Geotechnical Plan of Development.

2020

The United States Navy issues an easement for the B2H project. Based on the DPO, ODOE issues a Proposed Order and notice for Contested Case. Preparations begin for several pre-construction activities, which include completing LiDAR (aerial mapping) for the entire B2H project route and preparations for initiating detailed design.

2021

Idaho Power and reviewing agencies continue to meet with interested groups, affected landowners, community leaders, and elected officials. Idaho Power continues to conduct fieldwork to inform the state and federal review processes. The BLM continued NHPA Section 106 consultation. The ODOE continued with its contested case proceeding. A federal court ruled against a lawsuit brought against the BLM and United States Forest Service (USFS) regarding their ROD for B2H. Detailed design, geotechnical investigation, right-of-way option acquisition, and survey work begins.

B2H Route History

As stated previously, the need for the B2H project was first identified in the 2006 IRP. At that time, the transmission line was contemplated as a line between Boise and McNary. The project evolved into a 500 kV line between the Boardman area and the Hemingway Transmission Station. During scoping and the CAP process, a considerable number of routes through western, central, and eastern Oregon, and southern Washington were considered to connect Hemingway and the Boardman area. Figure D-1 is a snapshot the routes considered during this timeframe.

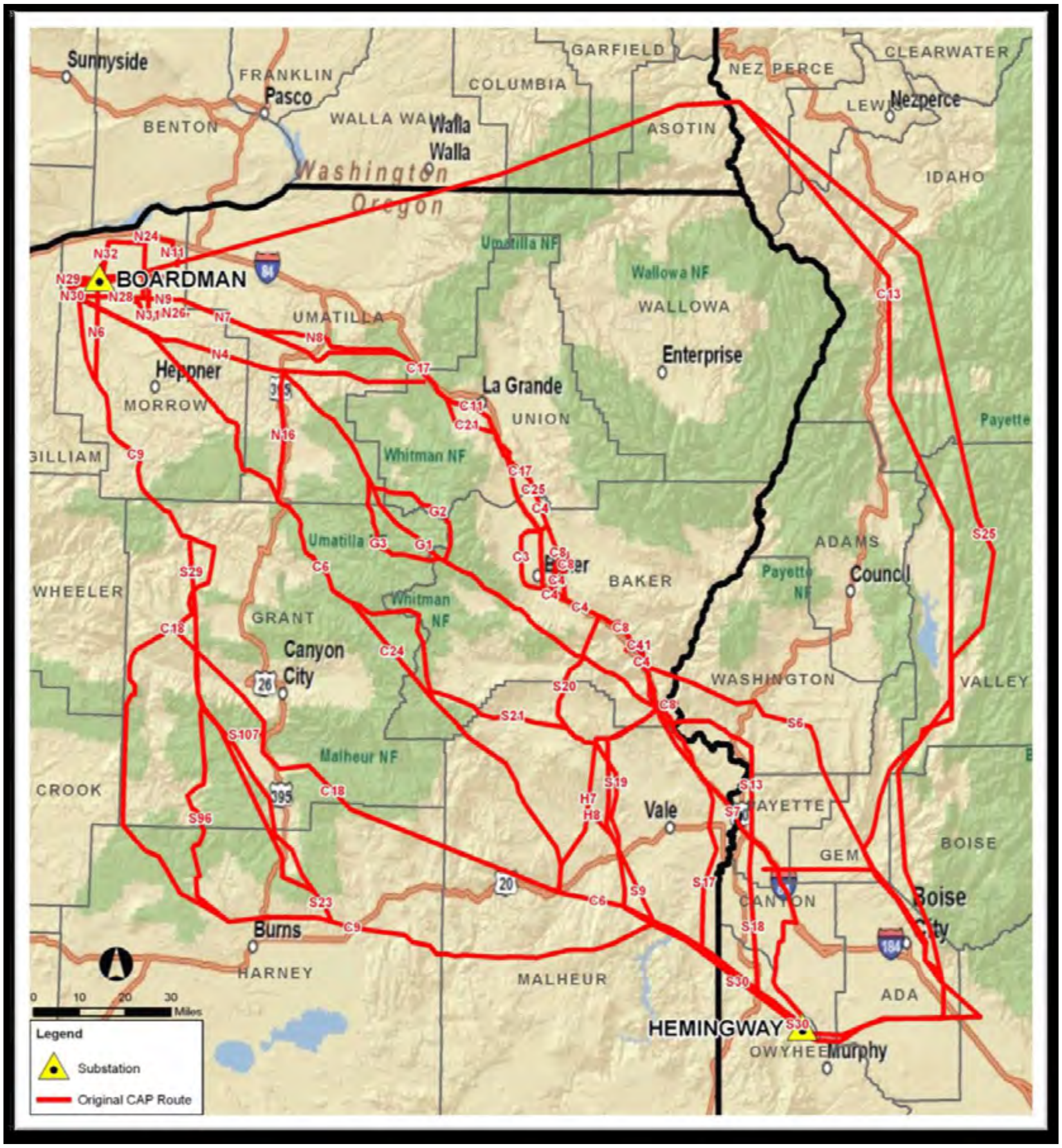

Figure D-1. Routes developed by the Community Advisory Process teams (2009 timeframe)

The CAP process resulted in Idaho Power submitting the route shown in Figure D-2 as the company's proposed route in the BLM-led NEPA process.

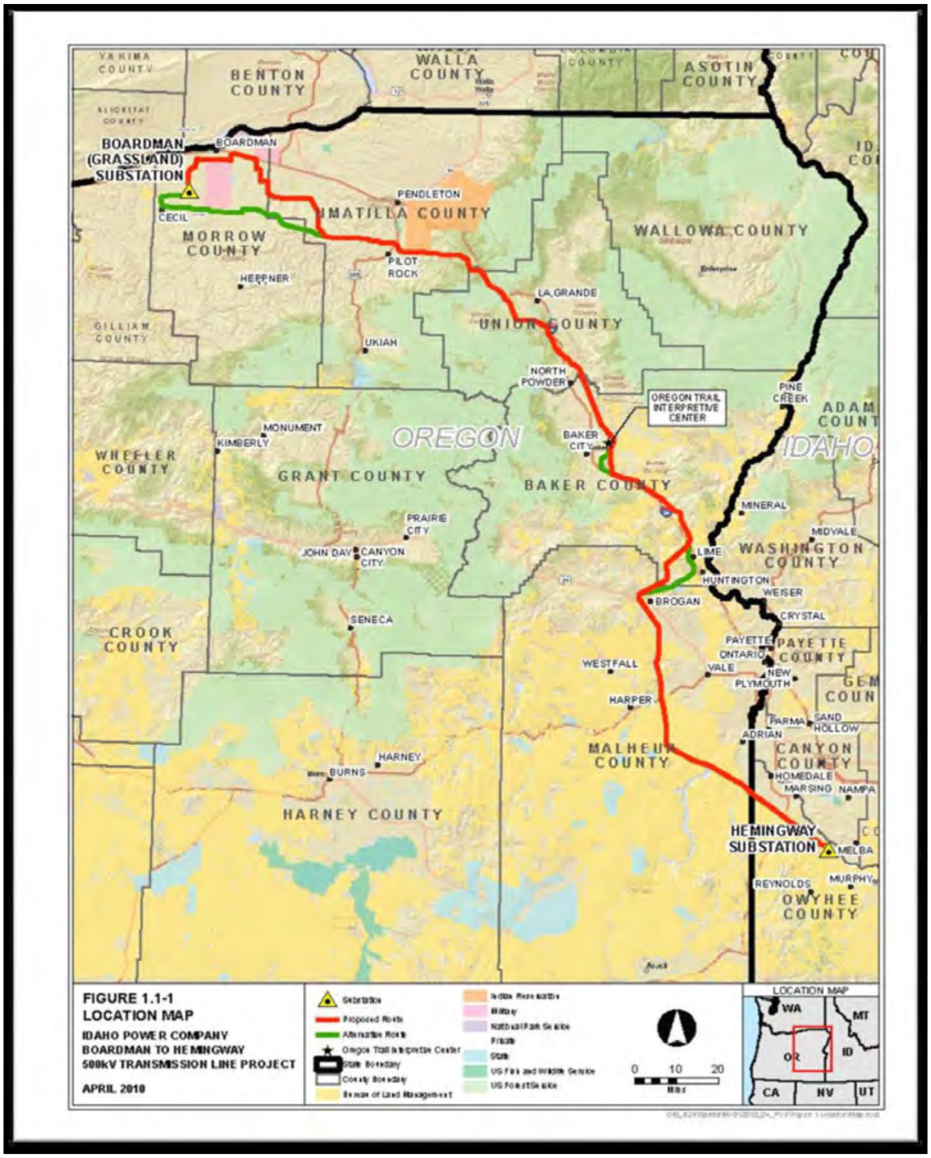

Figure D-2. B2H proposed route resulting from the Community Advisory Process (2010 timeframe)

The BLM considered Idaho Power's proposed route, along with a few other reasonable alternative routes, in the NEPA process. Figure D-3 shows the route alternatives and variations considered in the BLM's November 2016 Final EIS.

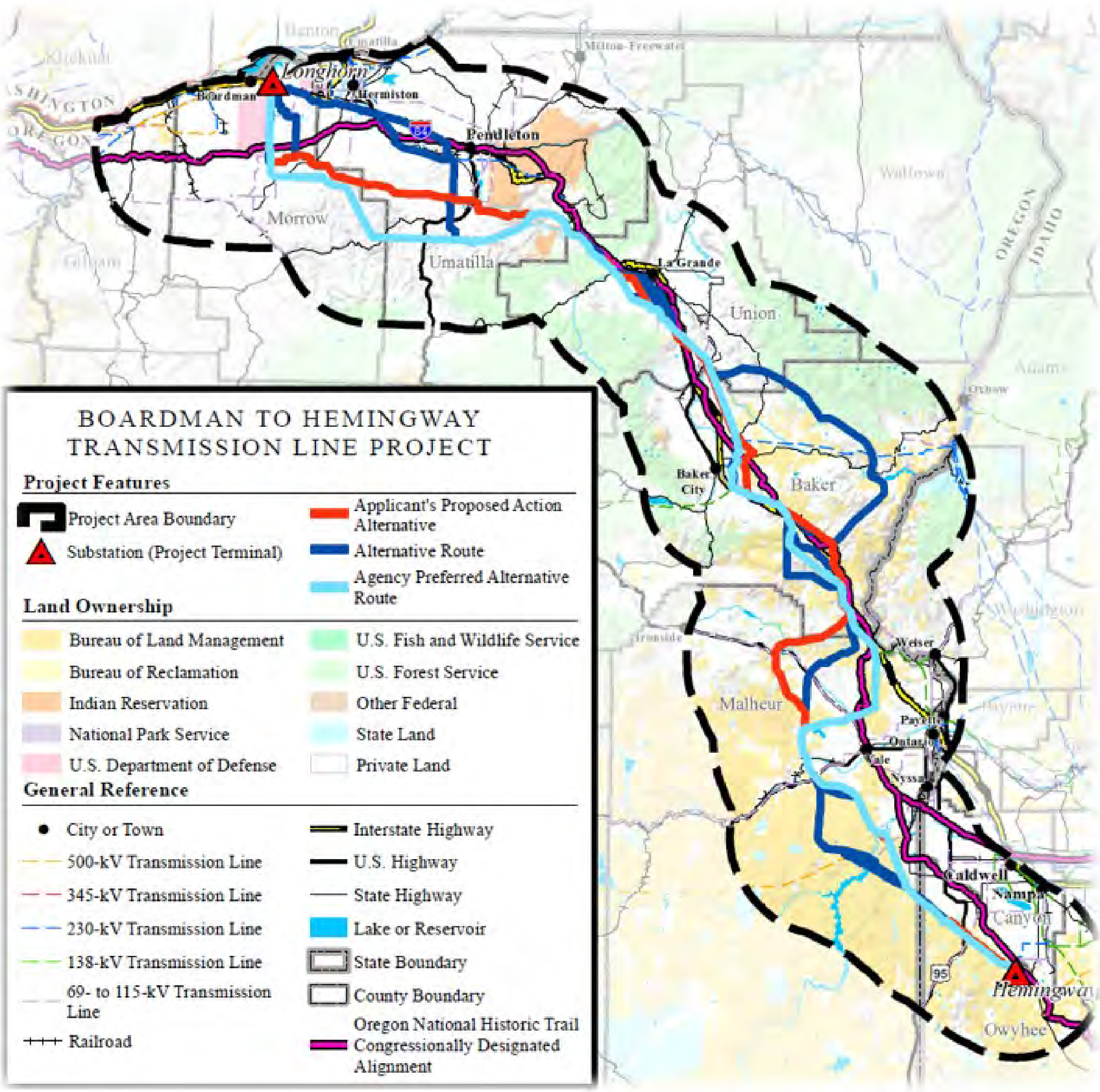

Figure D-3. BLM final EIS routes

The conclusion of the BLM-led NEPA process, the BLM's ROD, resulted in a singular route—the BLM's Agency Preferred route. The 293.4-mile approved route will run across 100.3 miles of federal land (managed by the BLM, the USFS, the Bureau of Reclamation, and the United States Department of Defense), 190.2 miles of private land, and 2.9 miles of state lands. Figure D-4 shows the BLM's Agency Preferred route.

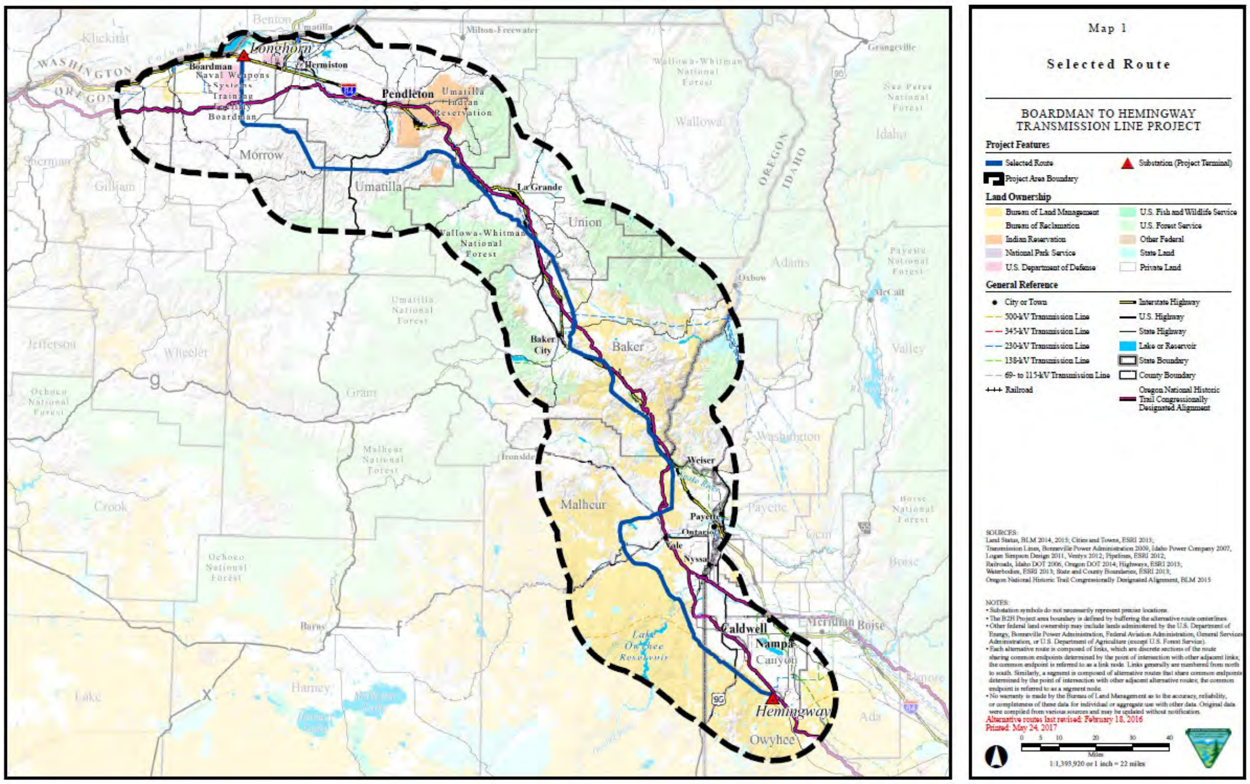

Figure D-4. BLM Agency Preferred route from the 2017 BLM ROD

As discussed previously, the BLM-led NEPA process and the EFSC process are separate and distinct processes. Idaho Power submitted its Amended Application for Site Certificate to the ODOE in summer 2017. The route Idaho Power submitted to the ODOE as part of the Application for Site Certificate is very similar to the BLM's Agency Preferred route, except for a small sections across private property in the La Grande area. The BLM's Agency Preferred route in this area was a surprise to Idaho Power and seemingly all stakeholders and landowners in the area.

At the time of EFSC application finalization (which was prior to the Final EIS release), Idaho Power did not feel as if there was a stakeholder consensus preference between the county's preferred route and the modified route west of the City of La Grande. Therefore, Idaho Power brought both alternatives into the EFSC application. Since that time, Idaho Power understands that the Morgan Lake route alternative, on balance, appears to be preferred by the majority of the groups previously identified.

Figure D-5 shows the route Idaho Power submitted in its 2017 EFSC Application for Site Certificate.

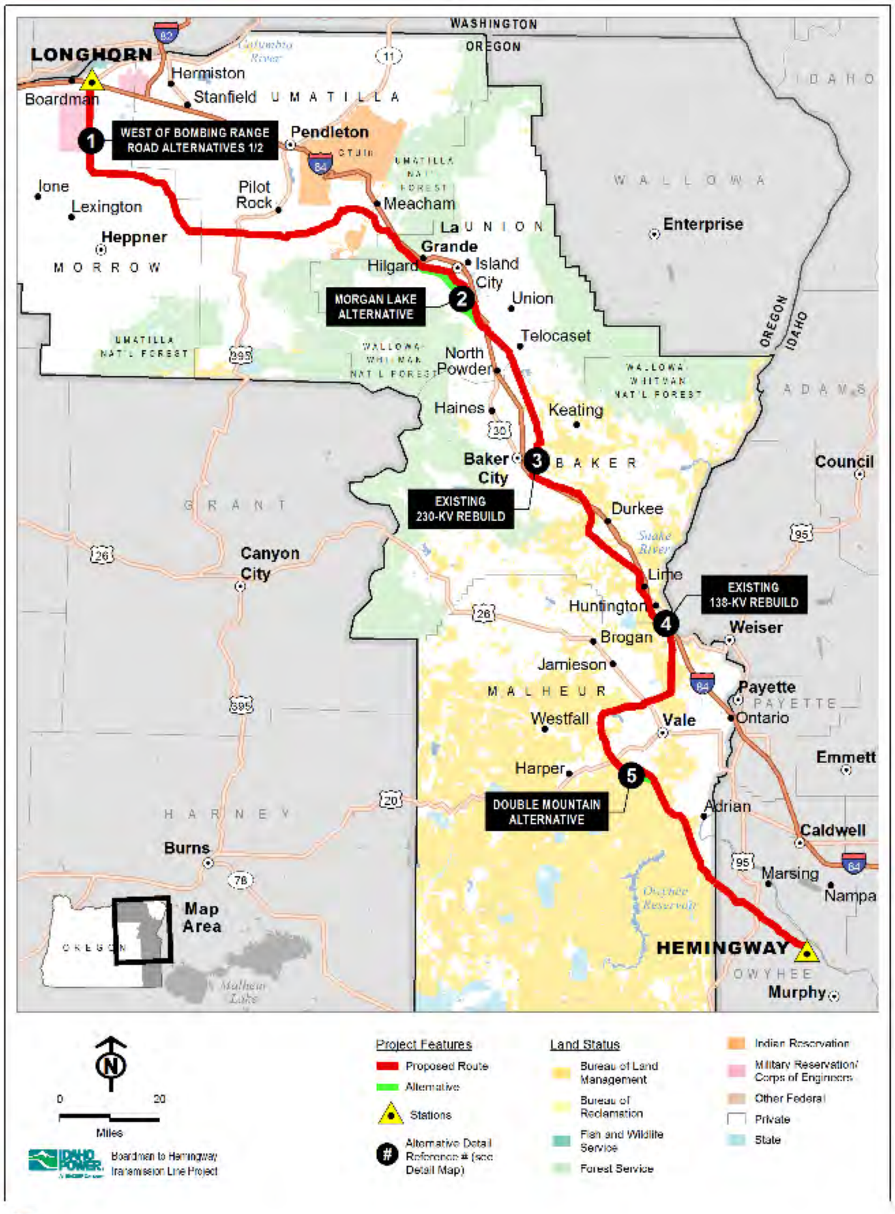

Figure D-5. B2H route submitted in 2017 EFSC Application for Site Certificate

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The results of the LTCE model indicate that the conversion of units 1 and 2 to natural gas in 2023 is economical. The Preferred Portfolio identifies exits for units 3 and 4 year-end 2025 and 2028, respectively. To ensure the robustness of these modeling outcomes, the company performed a significant number of validation and verification studies around the Bridger conversions and coal exit dates. These validation and verification studies are detailed in Chapter 9.

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The Preferred Portfolio, which includes B2H, is significantly more cost-effective than the best alternative portfolio that did not include B2H.

- Base with B2H Portfolio NPV (Preferred Portfolio)—$~~7,915.7~~7,942.4 million
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- B2H NPV Cost Effectiveness Differential—$~~269.6~~265.5 million

Under planning conditions, the Base with B2H (Preferred Portfolio) is approximately $~~270~~ 266 million more cost effective than the best portfolio that did not include the B2H project. Detailed portfolio costs can be found in Chapter 10.

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B2H's value to Idaho Power's customers is substantial, and it is a key least-cost resource.

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Finally, B2H is an important step in moving Idaho Power toward its 2045 clean energy goal. The B2H 500-kV line adds significant regional capacity with some remaining unallocated east-to-west capacity. Additional parties may reduce costs and further optimize the project for all participants.

Project Participants

In January 2012, Idaho Power entered into a joint funding agreement with PacifiCorp and BPA to pursue permitting of the project. The agreement designates Idaho Power as the permitting project manager for the B2H project. Table 7.2 shows each party's B2H capacity and permitting cost allocation.

Table 7.2 B2H capacity and permitting cost allocation

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

For the 2021 IRP, Idaho Power modeled B2H assuming that BPA transitions from an ownership stake in the B2H project to a service-based stake in the project. Further details regarding this assumption will be provided in *Appendix D*, which is anticipated to be filed during the first quarter of 2022. Table 7.3 shows what each party's new B2H capacity allocation would be, given this assumption.

Each of the portfolios designed under the AURORA LTCE process, that are in contention for the Preferred Portfolio, were evaluated through three different hourly simulations shown in Table 10.2.

Table 10.2 AURORA hourly simulations

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

The three combinations include the planning case scenarios as well as the bookends for natural gas and carbon adder price forecasts.

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 three hourly simulations, where only the pricing forecasts were changed, are shown in Table 10.3. These different portfolios and their associated costs can be compared as potential options for a preferred portfolio.

Table 10.3 2021 IRP portfolios, NPV years 2021–2040 ($ x 1,000)

Portfolio	Planning Gas, Planning Carbon	Planning Gas, Zero Carbon	High Gas, High Carbon
Base with B2H	$~~7,915,702~~7,942,428	$~~7,186,761~~7,213,486	$~~9,832,001~~9,858,726
Base B2H PAC Bridger Alignment	$~~7,999,347~~8,021,906	$~~7,152,955~~7,175,514	$~~9,932,925~~9,955,484
Base without B2H	$~~8,192,830~~8,219,281	$~~7,784,545~~7,810,996	$~~9,474,983~~9,501,435
Base without B2H without Gateway West[35]	$~~8,441,414~~8,470,101	-	-
Base without B2H PAC Bridger Alignment	$~~8,185,334~~8,207,893	$~~7,588,228~~7,610,787	$~~9,652,891~~9,675,450
Base with B2H—High Gas High Carbon Test[36]	$~~7,997,339~~8,024,064	-	$~~9,424,935~~9,451,660

[35] The company did not continue further evaluation of this portfolio beyond planning conditions due to the portfolio's inferior performance (high-cost, poor reliability, and poor emissions performance).

[36] All portfolios were optimized with planning conditions. The "Base with B2H—High Gas High Carbon (HGHC) Test" portfolio includes total renewables equivalent to the "Base without B2H" portfolio and was evaluated to test B2H as an independent variable. The results indicate that B2H remains cost effective, independent of gas price and carbon price and that a pivot to even more renewables in a future with a high gas and carbon price would be appropriate.

This comparison, as well as the stochastic risk analysis applied to these portfolios (see the Stochastic Risk Analysis section of this chapter), indicate the Base with B2H portfolio best minimizes both cost and risk and is the appropriate choice for the Preferred Portfolio.

The scenarios listed in Table 10.4 were sensitivities tested on the Preferred Portfolio and are included to show the associated costs. Each was evaluated under planning natural gas and carbon adder forecasts.

Table 10.4 2021 IRP Sensitivities, NPV years 2021–2040 ($ x 1,000)

Sensitivity	Cost
Preferred Portfolio (Base with B2H)	$~~7,915,702~~7,942,428
SWIP-North	$~~7,887,562~~7,914,287
CSPP Wind Renewal Low	$~~7,892,585~~7,919,311
CSPP Wind Renewal High	$~~7,926,005~~7,952,730

The validation and verification tests are listed in Table 10.5. These were modeling simulations performed on the Preferred Portfolio, with changes to the resources identified in the 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.

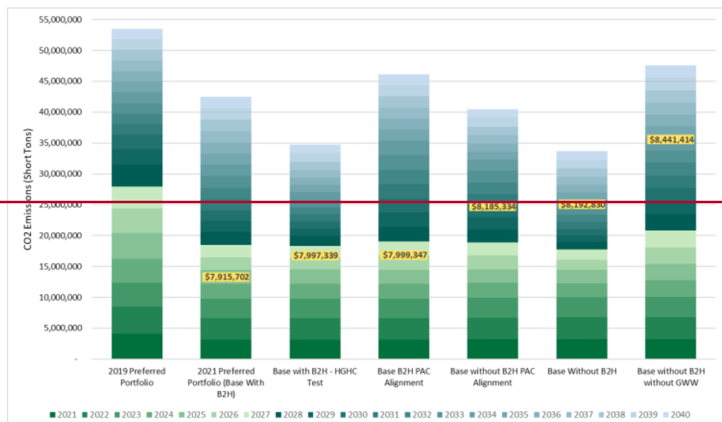
Table 10.5 2021 IRP validation and verification tests, NPV years 2021–2040 ($ x 1,000)

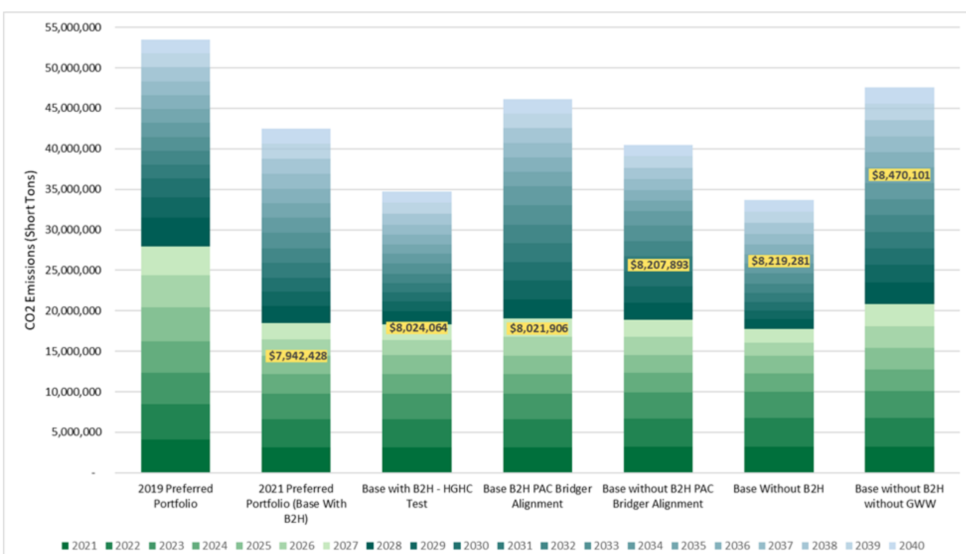
Validation & Verification Tests	Cost
Preferred Portfolio (Base with B2H)	$~~7,915,702~~7,942,428
Demand Response	$~~7,917,643~~7,944,368
Energy Efficiency	$~~8,143,113~~8,169,838
Natural Gas in 2028 Rather than Solar and Storage	$~~8,052,194~~8,078,645
Bridger Exit Units 1 & 2 at the End of 2023	$~~8,073,162~~8,077,805
Bridger Exit Unit 2 at the End of 2026	$~~7,997,648~~8,014,305
Bridger Unit 2 Delayed Gas Conversion (2027)	$~~7,938,805~~7,962,665
Bridger Exit Unit 4 in 2027	$~~7,925,427~~7,951,878
Bridger Exit Units 3 and 4 in 2028 and 2030	$~~7,969,378~~7,997,453
Geothermal	$~~7,973,781~~8,000,506
Biomass	$~~7,968,264~~7,994,989
Valmy Unit 2 Exit in 2023	$~~7,930,664~~7,957,116
Valmy Unit 2 Exit in 2024	$~~7,929,939~~7,956,390

Portfolio Emission Results

The company is seeking to execute on the actions identified in the Action Plan window. Therefore, the company evaluated the CO_2 emissions within the Action Plan window for each portfolio in contention for the Preferred Portfolio, along with the SWIP-North portfolio.

Figure 10.2 compares the full 20-year emissions of the company's 2019 Preferred Portfolio to the top contending portfolios in the 2021 IRP. In Figure 10.2, the 2019 Preferred Portfolio is on the far left, adjacent to the 2021 Preferred Portfolio on its immediate right. Compared to the 2019 Preferred Portfolio, the 2021 Preferred Portfolio has cumulative emissions reductions of about 21%. As can be seen on Figure 10.2, the other 2021 portfolios each reflect reduced emissions as compared to the 2019 Preferred Portfolio and are sorted by present value portfolio cost from left to right. The costs associated with each portfolio are shown in the yellow highlights. While 2021 IRP portfolios are shown on Figure 10.1 to have relatively similar emissions output during the Action Plan window, three portfolios have lower projected emissions than the 2021 Preferred Portfolio over the full 20-year planning horizon. However, it is important to note that each of those three portfolios present higher expected cost. The information presented on Figures 10.1 and 10.2 demonstrate 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 potential CO_2 emissions.





SWIP-North Opportunity Evaluation

The SWIP-North opportunity evaluation tests whether Idaho Power customers would potentially benefit from Idaho Power's involvement in the project. Based on the NPV cost results detailed in Table 10.4, the SWIP-North project appears to be worth further exploration.

- Preferred Portfolio (Base with B2H) NPV—$~~7,915,702~~7,942,428
- SWIP-North Portfolio NPV—$~~7,887,562~~7,914,287

In this opportunity evaluation, the company made assumptions about SWIP-North, and its cost and capacity benefits, which are detailed more in Chapter 7. The company is not familiar with any current partnership arrangements associated with the project, whether there are opportunities to participate in the project, or the feasibility of the project in general and its associated in-service date. Given the possible benefits to Idaho Power customers, the company will engage the SWIP-North project developer and look to perform a more detailed evaluation of SWIP-North in future IRPs.

B2H Robustness Testing

The company evaluated B2H assuming five different planning margin contributions, four different costs (various contingency amounts), and two different in-service dates to consider the robustness of the B2H project.

B2H Capacity Evaluation

When the B2H project is placed into service, currently scheduled for pre-summer 2026, the company will have access to as much as 550 MW of summer capacity. In recent IRPs, the company has planned to utilize 500 MW of B2H capacity to access the Mid-C markets and purchase power.

As part of the 2021 IRP, the company looked at portfolio costs assuming the company can access 350 MW, 400 MW, 450 MW, 500 MW (the Preferred Portfolio), and 550 MW of capacity. The sensitivities with capacity amounts less than 500 MW are set up to evaluate risk related to reduced market access. The 550 MW capacity amount sensitivity quantifies potential benefits associated with leveraging additional market purchases to avoid the need for a new resource. To evaluate the impact of different B2H capacity levels, the company added or subtracted comparable capacity in the form of battery storage (the least-cost alternative to providing sufficient amounts of capacity) to maintain an adequate planning margin, while maintaining the same cost of B2H (i.e., B2H capacity's contribution toward the planning margin is reduced with no offsetting cost reduction). The resulting total portfolio costs are detailed in Table 10.8.

Table 10.8 B2H capacity sensitivities

	Portfolio NPV	Potential Offsetting Costs Not Included (NPV)
Base B2H Portfolio—350 MW Planning Contribution	$~~8,042~~8,069 million	$51 million
Base B2H Portfolio—400 MW Planning Contribution	$~~7,992~~8,019 million	$34 million
Base B2H Portfolio—450 MW Planning Contribution	$~~7,953~~7,979 million	$17 million
Base B2H Portfolio (500 MW)	$~~7,916~~7,942 million	$0
Base B2H Portfolio—550 MW Planning Contribution	$~~7,884~~7,911 million	$0
Base without B2H PAC Bridger Alignment Portfolio (for comparison)	$~~8,185~~8,208 million	N/A

Table 10.8 shows that even with a substantially reduced planning margin contribution, B2H portfolios remain cost effective. Additionally, if the company is able to access an additional 50 MW from the Mid-C market, that may present a cost-saving opportunity for customers.

The "Potential Offsetting Costs Not Included" column represents the possibility of selling wheeling service utilizing the B2H capacity that is not being utilized by the company in the given scenario. This offsetting cost is not factored into the portfolio NPV.

B2H Cost Risk Evaluation

A transmission line such as B2H requires significant planning, organization, labor, and material over a multi-year process to complete and place in-service. Evaluating cost risks to ensure cost-effectiveness (i.e., a tipping point analysis) is an important consideration when planning for such a project. Table 10.9 details the cost of the B2H project with 0%, 10%, 20%, and 30% cost contingencies.

Table 10.9 B2H cost sensitivities

	B2H Cost Idaho Power Share TOTAL	B2H Cost 2021 IRP NPV
B2H 0% Contingency	$485 million	$159.6 million
B2H 10% Contingency	$526 million	$178.4 million
B2H 20% Contingency	$566 million	$197.2 million
B2H 30% Contingency	$607 million	$216.1 million

Utilizing the numbers in Table 10.8 and comparing them to the difference between the Preferred Portfolio (Base with B2H) and the Base without B2H PAC Bridger Alignment portfolio, the B2H project would have to increase significantly beyond a 30% contingency before the project would no longer be cost-effective. While this is already a significant margin, it should be noted that there are other unquantified benefits to the B2H project that if quantified, would further widen this gap. These items will be discussed in more detail in the forthcoming *Appendix D–Transmission Supplement*, which is anticipated to be filed in the first quarter of 2022.

B2H In-Service Date Risk Evaluation

The current planned in-service date for B2H is prior to the summer of 2026. This date is necessary to meet the peak demand growth needs, as well as fill in for the Valmy Unit 2 exit occurring at the end of 2025, and to facilitate the exit of Bridger Unit 3, as recommended as part of the Preferred Portfolio.

Should the B2H in-service date slip to 2027 due to a delay in receiving a permit, supply chain constraints, or other unforeseen issues, the exit of Bridger Unit 3 will certainly be delayed, and other new resources will be required in 2026. Table 10.10 details the cost change of B2H adjusting to 2027, and the new comparison to the Base without B2H PAC Bridger Alignment portfolio (the best B2H-excluded portfolio).

Table 10.10 B2H 2027 portfolio costs, cost sensitivities ($ x 1,000)

	Portfolio Costs	Portfolio Cost Compared to B2H 2027 Portfolio
Preferred Portfolio (Base with B2H)	$~~7,915,702~~7,942,428	-$~~69,062~~69,090
Base with B2H in 2027	$~~7,984,764~~8,011,517	-
Base without B2H PAC Alignment	$~~8,185,334~~8,207,893	$~~200,570~~196,375

Slippage in the schedule from 2026 to 2027 would not be ideal for Idaho Power customers. However, B2H remains the most cost-effective long-term resource.

Regional Resource Adequacy

Northwest Seasonal Resource Availability Forecast

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

The assessment of regional resource adequacy is useful in understanding the liquidity of regional wholesale electric markets. For the 2021 IRP, Idaho Power reviewed the *Pacific Northwest Loads and Resources Study* by the BPA (White Book). For illustrative purposes, Idaho Power also downloaded FERC 714 load data for the major Washington and Oregon Pacific Northwest entities to show the difference in regional demand between summer and winter.

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Base without B2H without Gateway West[35]	$8,470,101	-	-
Base without B2H PAC Bridger Alignment	$8,207,893	$7,610,787	$9,675,450
Base with B2H—High Gas High Carbon Test[36]	$8,024,064	-	$9,451,660

[35] The company did not continue further evaluation of this portfolio beyond planning conditions due to the portfolio's inferior performance (high-cost, poor reliability, and poor emissions performance).

[36] All portfolios were optimized with planning conditions. The "Base with B2H—High Gas High Carbon (HGHC) Test" portfolio includes total renewables equivalent to the "Base without B2H" portfolio and was evaluated to test B2H as an independent variable. The results indicate that B2H remains cost effective, independent of gas price and carbon price and that a pivot to even more renewables in a future with a high gas and carbon price would be appropriate.

This comparison, as well as the stochastic risk analysis applied to these portfolios (see the Stochastic Risk Analysis section of this chapter), indicate the Base with B2H portfolio best minimizes both cost and risk and is the appropriate choice for the Preferred Portfolio.

The scenarios listed in Table 10.4 were sensitivities tested on the Preferred Portfolio and are included to show the associated costs. Each was evaluated under planning natural gas and carbon adder forecasts.

Table 10.4 2021 IRP Sensitivities, NPV years 2021–2040 ($ x 1,000)

Sensitivity	Cost
Preferred Portfolio (Base with B2H)	$7,942,428
SWIP-North	$7,914,287
CSPP Wind Renewal Low	$7,919,311
CSPP Wind Renewal High	$7,952,730

The validation and verification tests are listed in Table 10.5. These were modeling simulations performed on the Preferred Portfolio, with changes to the resources identified in the 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 10.5 2021 IRP validation and verification tests, NPV years 2021–2040 ($ x 1,000)

Validation & Verification Tests	Cost
Preferred Portfolio (Base with B2H)	$7,942,428
Demand Response	$7,944,368
Energy Efficiency	$8,169,838
Natural Gas in 2028 Rather than Solar and Storage	$8,078,645
Bridger Exit Units 1 & 2 at the End of 2023	$8,077,805
Bridger Exit Unit 2 at the End of 2026	$8,014,305
Bridger Unit 2 Delayed Gas Conversion (2027)	$7,962,665
Bridger Exit Unit 4 in 2027	$7,951,878
Bridger Exit Units 3 and 4 in 2028 and 2030	$7,997,453
Geothermal	$8,000,506
Biomass	$7,994,989
Valmy Unit 2 Exit in 2023	$7,957,116
Valmy Unit 2 Exit in 2024	$7,956,390

Portfolio Emission Results

The company is seeking to execute on the actions identified in the Action Plan window. Therefore, the company evaluated the CO_2 emissions within the Action Plan window for each portfolio in contention for the Preferred Portfolio, along with the SWIP-North portfolio.

Figure 10.2 compares the full 20-year emissions of the company's 2019 Preferred Portfolio to the top contending portfolios in the 2021 IRP. In Figure 10.2, the 2019 Preferred Portfolio is on the far left, adjacent to the 2021 Preferred Portfolio on its immediate right. Compared to the 2019 Preferred Portfolio, the 2021 Preferred Portfolio has cumulative emissions reductions of about 21%. As can be seen on Figure 10.2, the other 2021 portfolios each reflect reduced emissions as compared to the 2019 Preferred Portfolio and are sorted by present value portfolio cost from left to right. The costs associated with each portfolio are shown in the yellow highlights. While 2021 IRP portfolios are shown on Figure 10.1 to have relatively similar emissions output during the Action Plan window, three portfolios have lower projected emissions than the 2021 Preferred Portfolio over the full 20-year planning horizon. However, it is important to note that each of those three portfolios present higher expected cost. The information presented on Figures 10.1 and 10.2 demonstrate 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 potential CO_2 emissions.

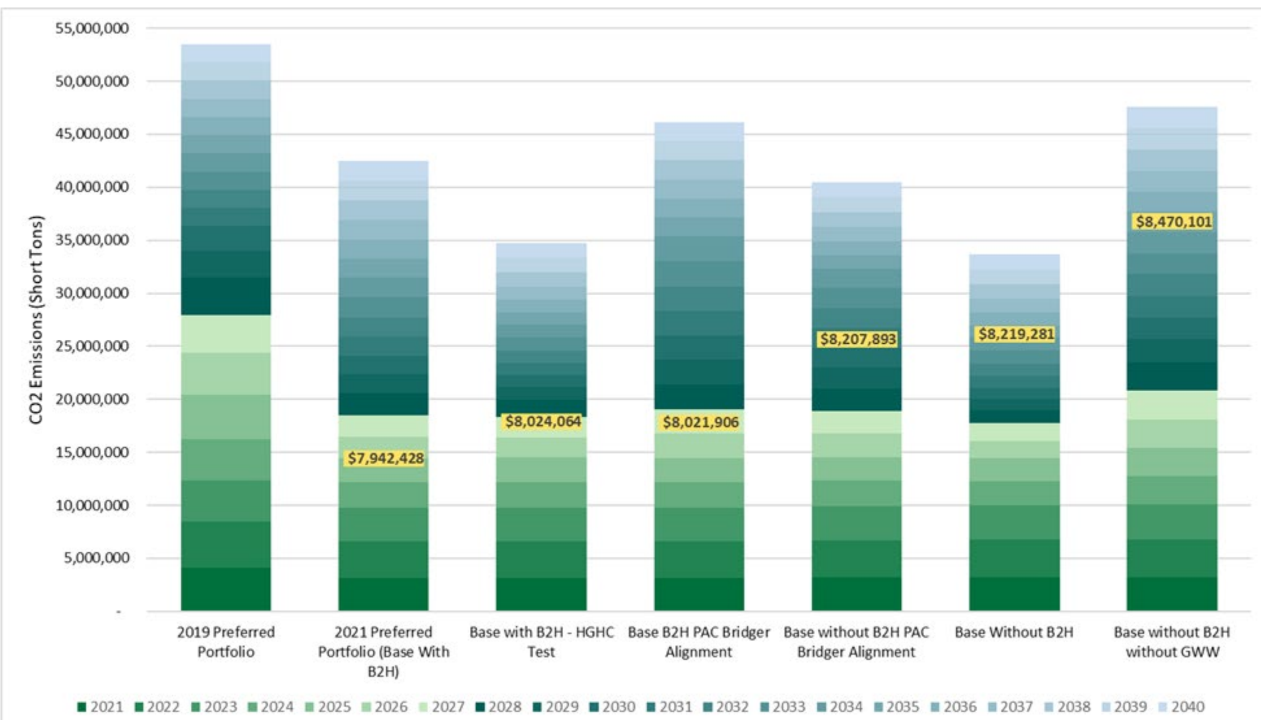

Figure 10.2 Estimated portfolio emissions from 2021–2040

In conclusion, the Preferred Portfolio (Base with B2H) strikes an appropriate balance of cost, risk, and emissions reductions over the Action Plan window. The Preferred Portfolio also lays a cost-effective foundation to build upon for further emissions reductions into the future.

SWIP-North Opportunity Evaluation

The SWIP-North opportunity evaluation tests whether Idaho Power customers would potentially benefit from Idaho Power's involvement in the project. Based on the NPV cost results detailed in Table 10.4, the SWIP-North project appears to be worth further exploration.

- Preferred Portfolio (Base with B2H) NPV—$7,942,428
- SWIP-North Portfolio NPV—$7,914,287

In this opportunity evaluation, the company made assumptions about SWIP-North, and its cost and capacity benefits, which are detailed more in Chapter 7. The company is not familiar with any current partnership arrangements associated with the project, whether there are opportunities to participate in the project, or the feasibility of the project in general and its associated in-service date. Given the possible benefits to Idaho Power customers, the company will engage the SWIP-North project developer and look to perform a more detailed evaluation of SWIP-North in future IRPs.

B2H Robustness Testing

The company evaluated B2H assuming five different planning margin contributions, four different costs (various contingency amounts), and two different in-service dates to consider the robustness of the B2H project.

B2H Capacity Evaluation

When the B2H project is placed into service, currently scheduled for pre-summer 2026, the company will have access to as much as 550 MW of summer capacity. In recent IRPs, the company has planned to utilize 500 MW of B2H capacity to access the Mid-C markets and purchase power.

As part of the 2021 IRP, the company looked at portfolio costs assuming the company can access 350 MW, 400 MW, 450 MW, 500 MW (the Preferred Portfolio), and 550 MW of capacity. The sensitivities with capacity amounts less than 500 MW are set up to evaluate risk related to reduced market access. The 550 MW capacity amount sensitivity quantifies potential benefits associated with leveraging additional market purchases to avoid the need for a new resource. To evaluate the impact of different B2H capacity levels, the company added or subtracted comparable capacity in the form of battery storage (the least-cost alternative to providing sufficient amounts of capacity) to maintain an adequate planning margin, while maintaining the same cost of B2H (i.e., B2H capacity's contribution toward the planning margin is reduced with no offsetting cost reduction). The resulting total portfolio costs are detailed in Table 10.8.

Table 10.8 B2H capacity sensitivities

	Portfolio NPV	Potential Offsetting Costs Not Included (NPV)
Base B2H Portfolio—350 MW Planning Contribution	$8,069 million	$51 million
Base B2H Portfolio—400 MW Planning Contribution	$8,019 million	$34 million
Base B2H Portfolio—450 MW Planning Contribution	$7,979 million	$17 million
Base B2H Portfolio (500 MW)	$7,942 million	$0
Base B2H Portfolio—550 MW Planning Contribution	$7,911 million	$0
Base without B2H PAC Bridger Alignment Portfolio (for comparison)	$8,208 million	N/A

Table 10.8 shows that even with a substantially reduced planning margin contribution, B2H portfolios remain cost effective. Additionally, if the company is able to access an additional 50 MW from the Mid-C market, that may present a cost-saving opportunity for customers.

The "Potential Offsetting Costs Not Included" column represents the possibility of selling wheeling service utilizing the B2H capacity that is not being utilized by the company in the given scenario. This offsetting cost is not factored into the portfolio NPV.

B2H Cost Risk Evaluation

A transmission line such as B2H requires significant planning, organization, labor, and material over a multi-year process to complete and place in-service. Evaluating cost risks to ensure cost-effectiveness (i.e., a tipping point analysis) is an important consideration when planning for such a project. Table 10.9 details the cost of the B2H project with 0%, 10%, 20%, and 30% cost contingencies.

Table 10.9 B2H cost sensitivities

	B2H Cost Idaho Power Share TOTAL	B2H Cost 2021 IRP NPV
B2H 0% Contingency	$485 million	$159.6 million
B2H 10% Contingency	$526 million	$178.4 million
B2H 20% Contingency	$566 million	$197.2 million
B2H 30% Contingency	$607 million	$216.1 million

Utilizing the numbers in Table 10.8 and comparing them to the difference between the Preferred Portfolio (Base with B2H) and the Base without B2H PAC Bridger Alignment portfolio, the B2H project would have to increase significantly beyond a 30% contingency before the project would no longer be cost-effective. While this is already a significant margin, it should be noted that there are other unquantified benefits to the B2H project that if quantified, would further widen this gap. These items will be discussed in more detail in the forthcoming

Appendix D–Transmission Supplement, which is anticipated to be filed in the first quarter of 2022.

B2H In-Service Date Risk Evaluation

The current planned in-service date for B2H is prior to the summer of 2026. This date is necessary to meet the peak demand growth needs, as well as fill in for the Valmy Unit 2 exit occurring at the end of 2025, and to facilitate the exit of Bridger Unit 3, as recommended as part of the Preferred Portfolio.

Should the B2H in-service date slip to 2027 due to a delay in receiving a permit, supply chain constraints, or other unforeseen issues, the exit of Bridger Unit 3 will certainly be delayed, and other new resources will be required in 2026. Table 10.10 details the cost change of B2H adjusting to 2027, and the new comparison to the Base without B2H PAC Bridger Alignment portfolio (the best B2H-excluded portfolio).

Table 10.10 B2H 2027 portfolio costs, cost sensitivities ($ x 1,000)

	Portfolio Costs	Portfolio Cost Compared to B2H 2027 Portfolio
Preferred Portfolio (Base with B2H)	$7,942,428	-$69,090
Base with B2H in 2027	$8,011,517	-
Base without B2H PAC Alignment	$8,207,893	$196,375

Slippage in the schedule from 2026 to 2027 would not be ideal for Idaho Power customers. However, B2H remains the most cost-effective long-term resource.

Regional Resource Adequacy

Northwest Seasonal Resource Availability Forecast

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

The assessment of regional resource adequacy is useful in understanding the liquidity of regional wholesale electric markets. For the 2021 IRP, Idaho Power reviewed the *Pacific Northwest Loads and Resources Study* by the BPA (White Book). For illustrative purposes, Idaho Power also downloaded FERC 714 load data for the major Washington and Oregon Pacific Northwest entities to show the difference in regional demand between summer and winter.