IDAHO POWER®
An IDACORP Company

INTEGRATED RESOURCE PLAN

2019

JUNE • 2019

APPENDIX D: B2H SUPPLEMENT

SAFE HARBOR STATEMENT

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

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EXECUTIVE SUMMARY

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

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

In addition to being the least-cost, lowest-risk resource to meet Idaho Power' resource needs, the B2H project has received national recognition for the benefits it will provide. The B2H project was selected by the Obama administration as one of seven nationally significant transmission projects that, when built, will help increase electric reliability, integrate new renewable energy into the grid, create jobs, and save consumers money. Most recently, B2H was acknowledged as complementing the Trump Administration's America First Energy Plan, which addresses all forms of domestic energy production. In a November 17, 2017, United States (US) Department of the Interior press release,[1] B2H was held up as "a Trump Administration priority focusing on infrastructure needs that support America's energy independence…" The release went on to say, "This project will help stabilize the power grid in the Northwest, while creating jobs and carrying low-cost energy to the families and businesses who need it…" The benefits

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

B2H is expected to bring to the region and nation have been recognized across both major political parties.

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

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

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

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

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

Certificate authorizing the construction of a transmission line (non-generating facility). Idaho Power's demonstration of need is based on the least-cost plan rule, for which the requirements can be met through a commission acknowledgement of the resource in the company's IRP.[3] Similar to the 2017 IRP, Idaho Power again seeks to satisfy EFSC's least-cost plan rule requirement through an acknowledgement of its 2019 IRP.

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

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

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

RESOURCE NEED EVALUATION

Resource Needs and Capacity Expansion Modeling

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

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

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

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

IRP Guideline Language—Transmission Evaluated on Comparable Basis

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

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

Boardman to Hemingway as a Resource

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

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

Capacity Costs

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

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

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

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

* Uses the B2H 350-MW average capacity

** Uses the B2H 500-MW capacity

***Uses on-peak capacity of 45 percent of installed nameplate capacity

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

Energy Cost

B2H provides Idaho Power with more capacity to the Pacific Northwest to purchase power from the Mid-Columbia (Mid-C) trading hub. Market power in the summer months has traditionally been a function of the price of natural gas. Therefore, in a B2H future where market prices are a function of natural gas prices, Idaho Power may pay a slight premium for summertime market power compared to a future in which Idaho Power owned its own combined-cycle gas plant. However, this B2H future would require less O&M costs than owning a combined-cycle gas plant over the course of a year.

The B2H portfolios' capacity costs are low enough that capacity installation savings far outweigh the potential additional energy costs, leading B2H to consistently be a low-cost resource option for Idaho Power's customers.

Market Overview

Power Markets

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

Six characteristics of successful electric trading markets include the following:

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

Mid-C Market

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

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

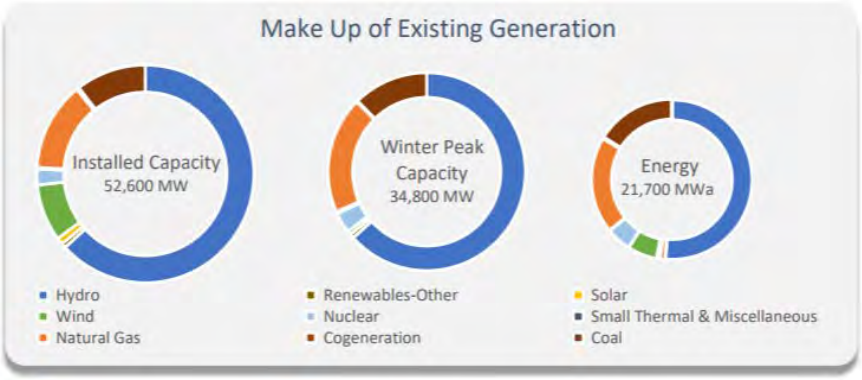

Figure 1. Northwest regional forecast (Source: 2017 PNUCC)[5]

In the western US, the other major market hubs are California–Oregon Border (COB), Four Corners (Arizona–New Mexico border), Mead (Nevada), Mona (Utah), Palo Verde (Arizona), and SP15 (California). The Mid-C market is very liquid. In 2018, on a day-ahead trading basis, daily average trading volume during heavy-load hours during June and July ranged from nearly 10,000 megawatt-hours (MWh) to over 49,000 MWh. When combining heavy-load hours with light-load hours, on a day-ahead trading basis, the monthly volumes for June and July were each approximately 1,600,000 MWhs. These volumes are in addition to daily broker trades and month-ahead trading volumes. Mid-C is by far the highest volume market hub in the west; frequently, Mid-C volumes are greater than the other hubs combined.

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

- Avista Utility
- BPA
- Chelan County Public Utility District (PUD)
- Douglas County PUD
- Eugene Water and Electric Board
- Idaho Power
- PacifiCorp
- Portland General Electric

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

- Powerex
- Puget Sound Energy
- Seattle City Light
- Tacoma Power

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

Mid-C and Idaho Power

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

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

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

The Mid-C market could be used more to economically serve Idaho Power customers, but Idaho Power's ability to transact at Mid-C is limited due to transmission capacity constraints between the Pacific Northwest and Idaho. In other words, sufficient transmission capacity is currently

unavailable during certain times of the year for Idaho Power to procure cost-effective resources from Mid-C for its customers, even though generation supply is available at the market.

Modeling of the Mid-C Market in the IRP

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

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

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

B2H Comparison to Other Resources

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

Table 2. High-level differences between resource options

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

Notes:

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

Idaho Power's Transmission System

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

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

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

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

Transmission Capacity Between Idaho Power and the Pacific Northwest

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

but less than the sum of the individual capacity ratings of each line. Figure 2 shows an overview of Idaho Power's high-voltage transmission system.

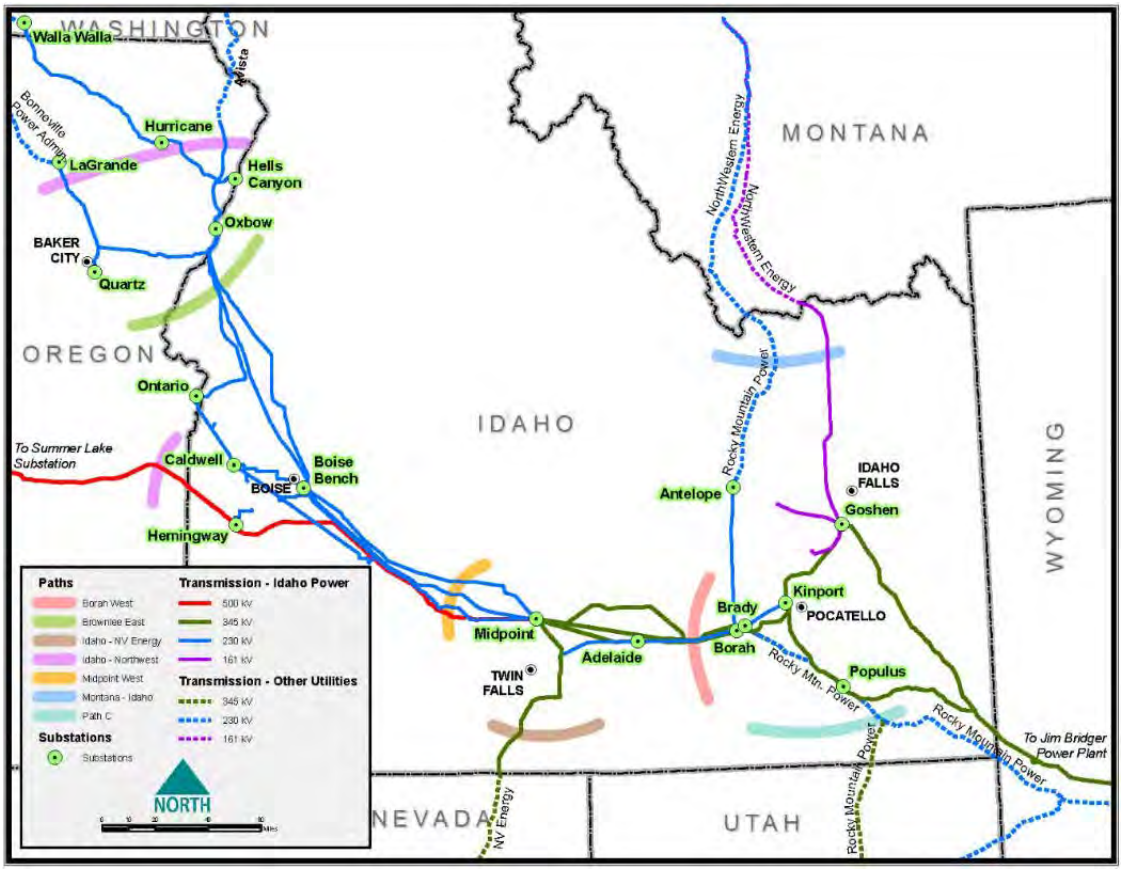

Figure 2. Idaho Power transmission system map

Table 3 details the capacity allocation between the Pacific Northwest and Idaho Power in 2019. The shaded rows represent capacity amounts that can be used to serve Idaho Power's native load. Although Idaho Power owns 1,280 MW of transmission capacity between the Pacific Northwest and Idaho Power's system, after all other uses are accounted for, Idaho Power will only able to use 309 MW to serve Idaho Power's native load in 2019. Idaho Power used 361 MW to serve BPA or PacifiCorp network load on Idaho Power's system, 280 MW were allocated to Transmission Reserve Margin (TRM), and 330 MW were allocated to Capacity Benefit Margin (CBM).

Table 3. Pacific Northwest to Idaho Power import transmission capacity from the 2016 transmission forecast

Firm Transmission Usage (Pacific Northwest to Idaho Power)	Capacity (July MW)
BPA Load Service (Network Customer)	360
Boardman Generation	60
Fighting Creek (PURPA)	4
Pallette Load (PacifiCorp—Network Customer)	1
TRM	280
CBM	330
Subtotal	**1,035**
Pacific Northwest Purchase (Idaho Power Load Service)	245
Total	**1,280**

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

CBM is transmission capacity Idaho Power sets aside, as unavailable for firm use, for the purposes of accessing reserve energy to recover from severe unplanned generation outages. Reserve generation capacity is critical and CBM allows a utility to reduce the amount of reserve generation capacity on its system by providing transmission availability to another market, such as the Pacific Northwest, which is rich with surplus capacity necessary for emergency conditions. Idaho Power's 330 MW of CBM is based on Idaho Power's share of the unplanned loss of two Jim Bridger units. The loss of two Jim Bridger units results in the removal of over 1,000 MW of generation in Wyoming, leaving Idaho Power and PacifiCorp searching to replace approximately 330 MW and 670 MW, respectively. Recovering from such an event, especially during peak summer load, can be extremely difficult without access to Pacific Northwest generation capacity, hence the reserve margin.

Montana–Idaho Path Utilization

To utilize Idaho Power's share of the Montana–Idaho 80 MW of capacity, Idaho Power must purchase transmission service from either Avista or BPA. This transmission system connects the

purchased resource in the Pacific Northwest to Idaho Power's transmission system. Avista or BPA transmits, or wheels, the power across their transmission system and delivers the power to Idaho Power's transmission system. The Montana–Idaho path is identified in Figure 2 above.

Idaho to Northwest Path Utilization

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

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

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

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

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

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

Regional Planning—Studies and Conclusions

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

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

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

As of December 31, 2018, B2H was selected into the NTTG's draft regional transmission plan. For the most recent updates related to Idaho Power's regional planning organization, please refer to the NTTG website at nttg.biz/.

THE B2H PROJECT

Project History

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

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

Public Participation

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

1. Identify community issues and concerns.
2. Develop a range of possible routes that address community issues and concerns.
3. Recommend proposed and alternate routes.

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

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

Ultimately, the route recommendation from the CAP was the route Idaho Power brought into the *National Environmental Policy Act of 1969* (NEPA) process as the proponent-recommended route. The NEPA process included additional opportunities for public comment at major milestones, and Idaho Power worked with landowners and communities along the way. Ultimately, the route selected through the NEPA process was based on the Bureau of Land Management's (BLM) analysis and public input. For more information on the CAP, including the final report[6], and Idaho Power's initial scoping activities, visit the documents section[7] on the B2H website.

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

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

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

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

[7] boardmantohemingway.com/documents.aspx

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

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

At the urging of local landowners along Bombing Range Road in Morrow County, Idaho Power has been working with local jurisdictional leaders, delegate representatives, farmers, ranchers, and other interested parties to gain the Navy's consideration of an easement along the eastern edge of the Boardman Bombing Range. This cooperative effort with the local area has benefited the Project, providing an approach that meets the interests and common good for all in the area. Idaho Power is still working with the Navy to obtain that easement, but all indications point to receiving an authorization from the Navy in 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 to the landowners. Idaho Power understood that both the Mill Creek and Morgan Lake route variations were favored over BLM's Agency Preferred Alternative (Glass Hill Alternative) by landowners, the Glass Hill Coalition, several stakeholders, and the Confederated Tribe of the Umatilla Indian Reservation due to concerns of impacts on areas that had no prior development. Idaho Power continued support of the community-favored routes in its Application for Site Certificate filed with the Oregon Department of Energy in September 2018. Idaho Power will work with Union County and local stakeholders to determine the route preference between the Morgan Lake and Mill Creek alternatives.

Project Activities

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

2006

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

2007

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

2008

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

2009

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

2010

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

2011

Additional public outreach resulted in additional route alternatives submitted to the BLM. The Obama Administration recognizes B2H as one of seven national priority projects[8].

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.

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

2013

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

2014

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

2015

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

2016

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

2017

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

2018

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

2019

The USFS issues ROW easement. ODOE issues a Draft Proposed Order. BPA issues a ROD for moving the existing 69 kV line from Navy property to accommodate the B2H project.

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

Route History

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

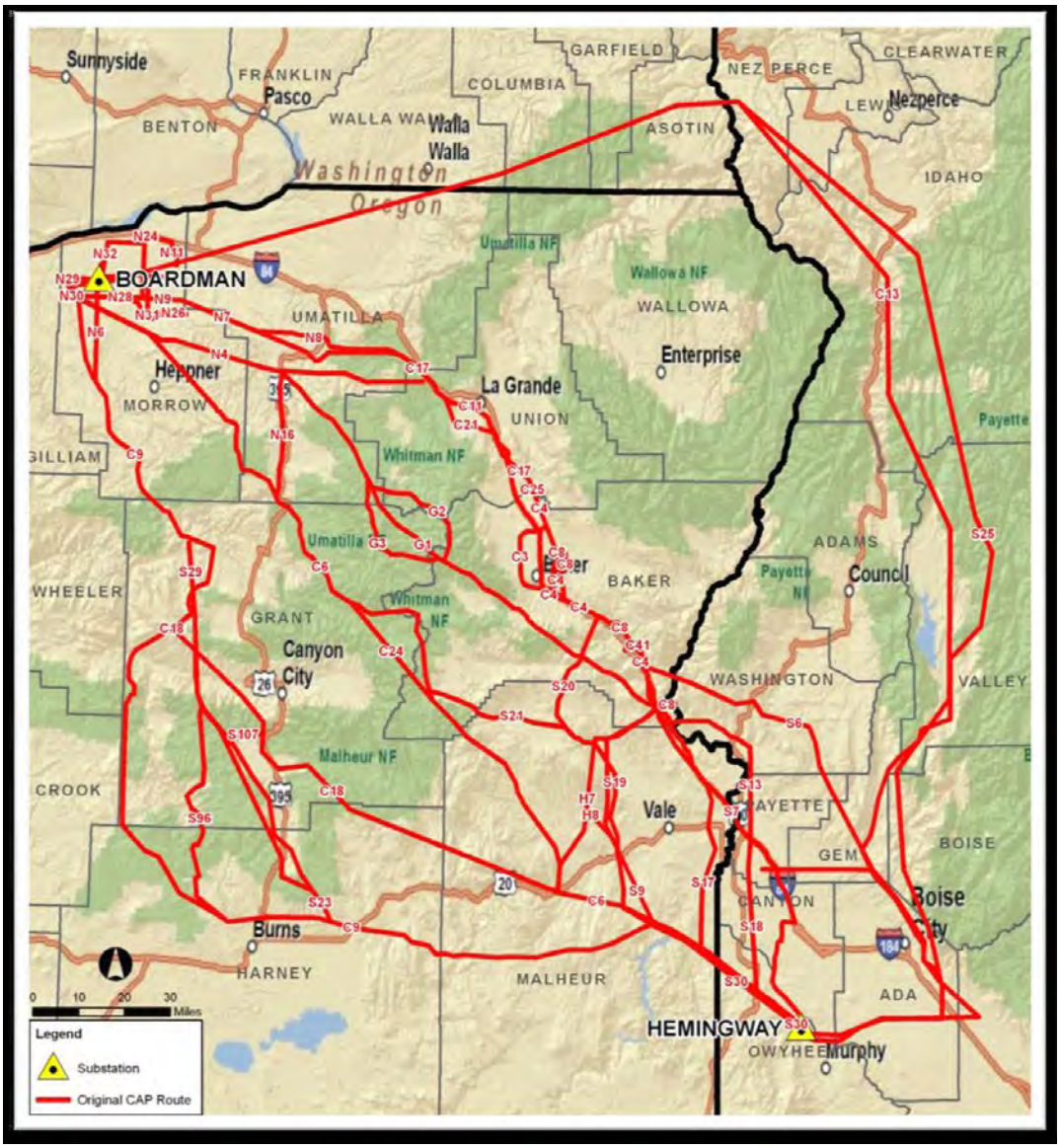

Figure 3. Routes developed by the CAP advisory teams (2009 timeframe)

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

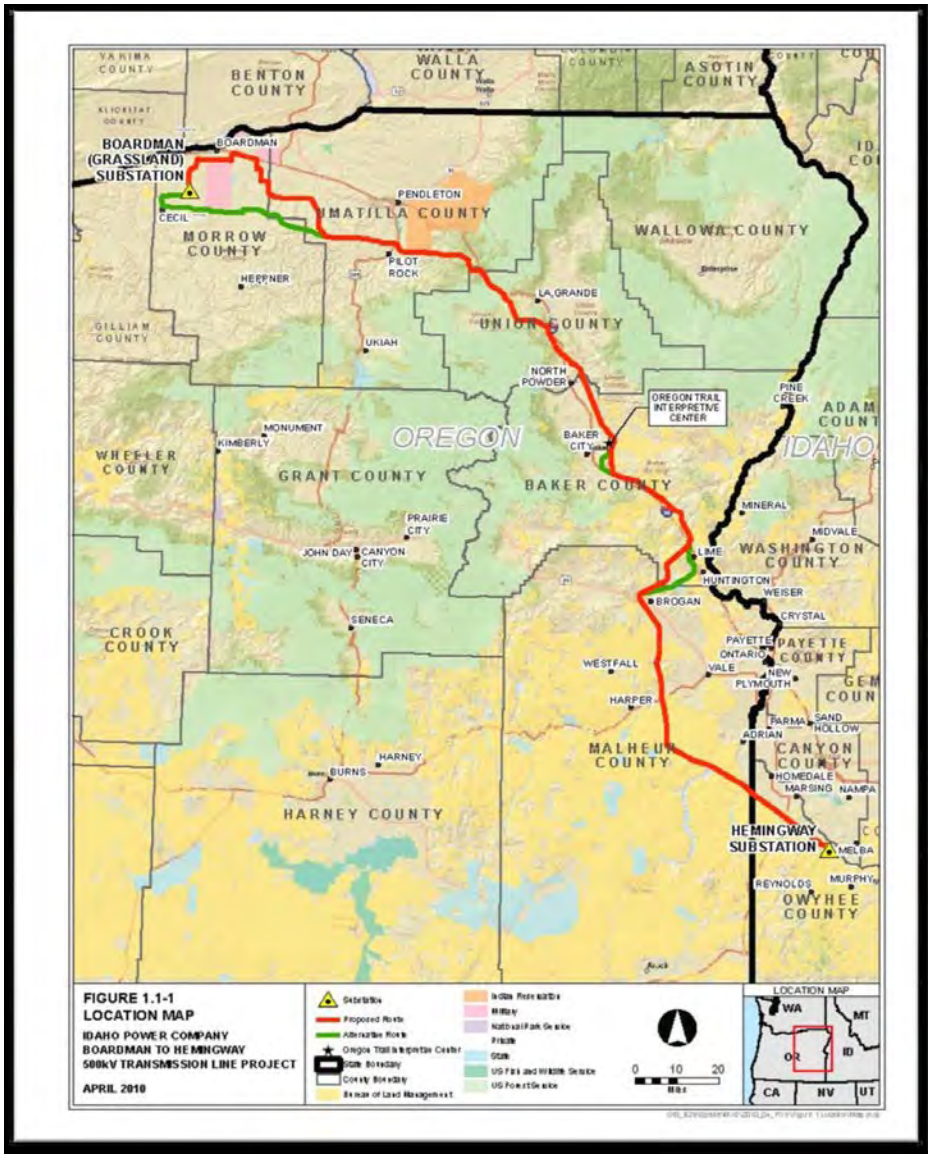

Figure 4. B2H proposed route resulting from the CAP process (2010 timeframe)

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

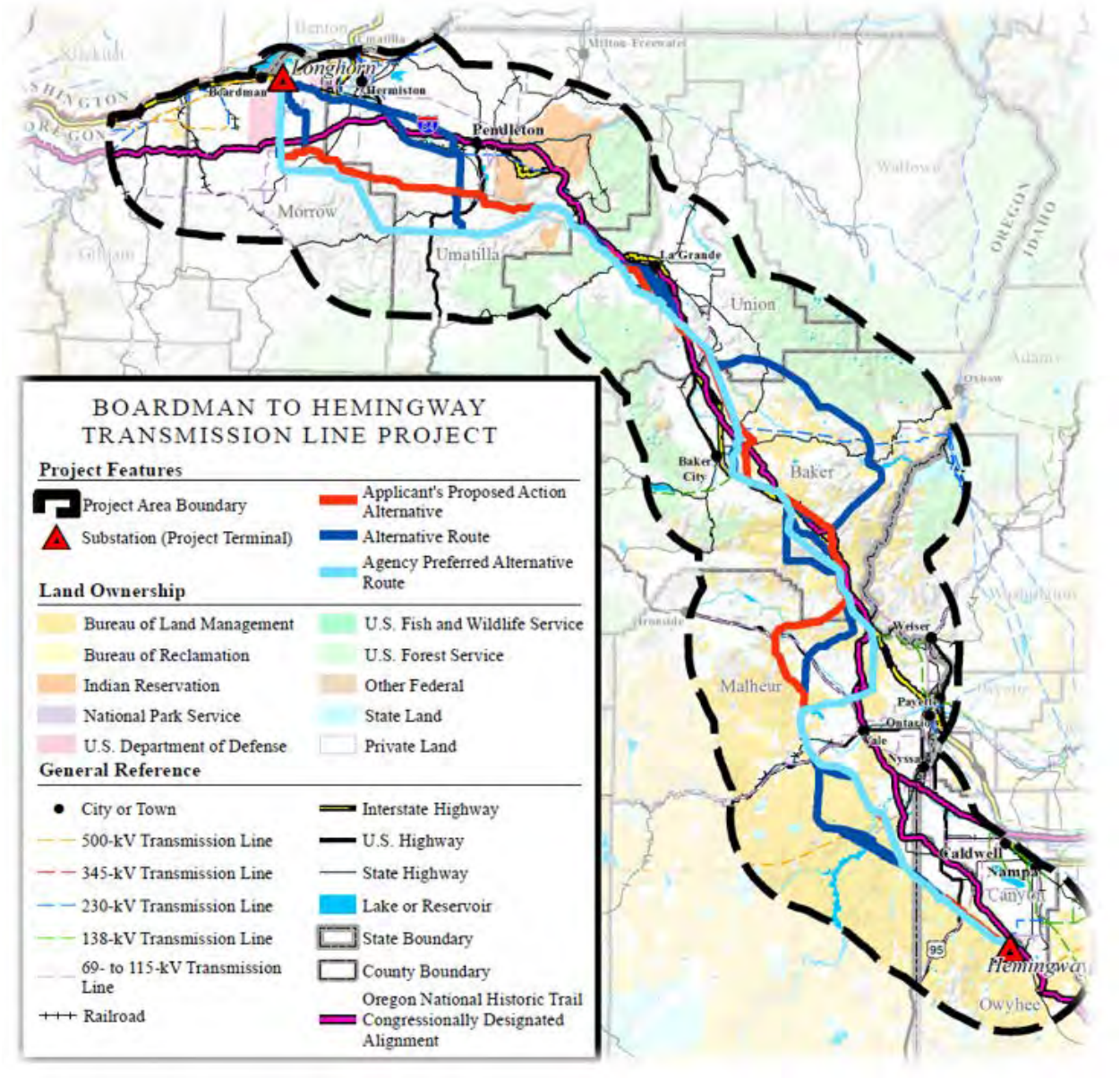

Figure 5. BLM final EIS routes

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

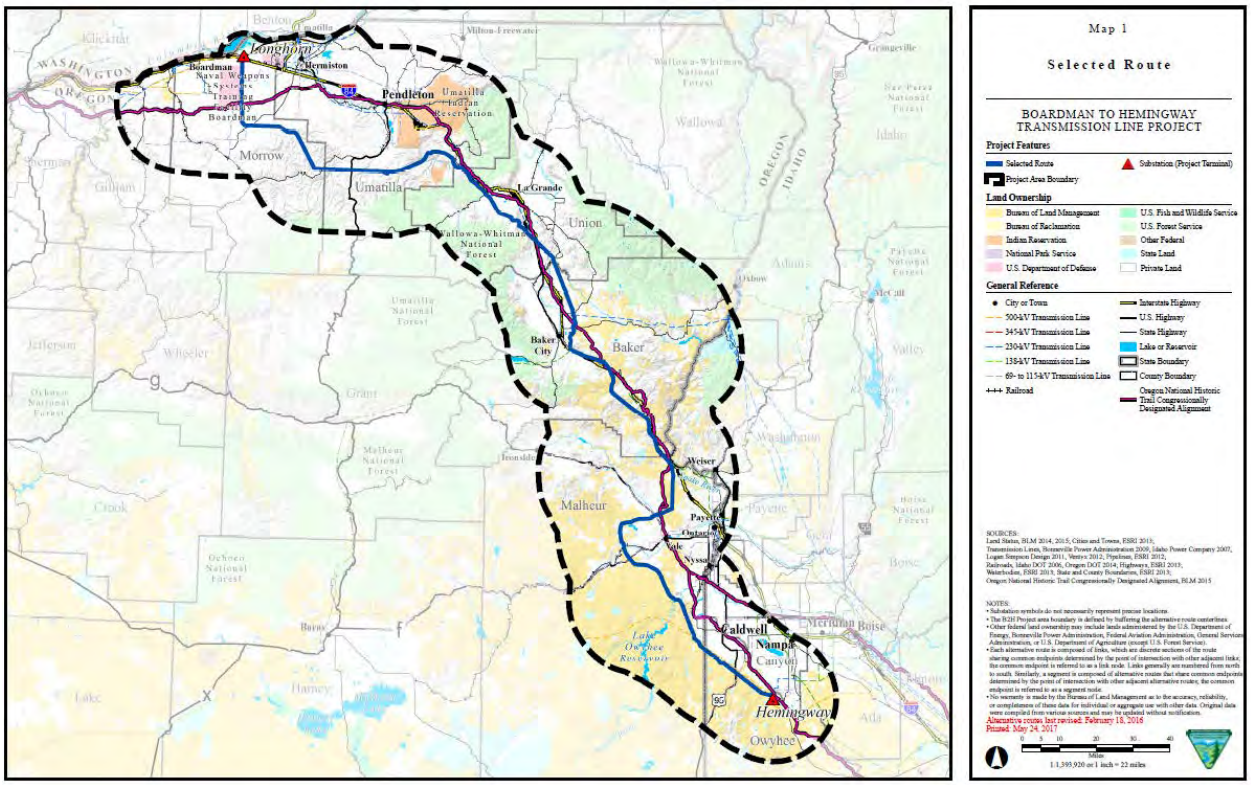

Figure 6. BLM Agency Preferred route from the 2017 BLM ROD

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

At the time of EFSC application finalization (which was prior to the Final EIS release), Idaho Power did not feel as if there was a stakeholder consensus preference between the County's preferred route and the modified route west of the City of La Grande. Therefore, Idaho Power brought both alternatives into the EFSC application. Idaho Power intends to continue to work with the community to finalize which of the two variations in this area will be constructed.

Figure 7 shows the route Idaho Power submitted in its 2017 EFSC Application for Site Certificate.

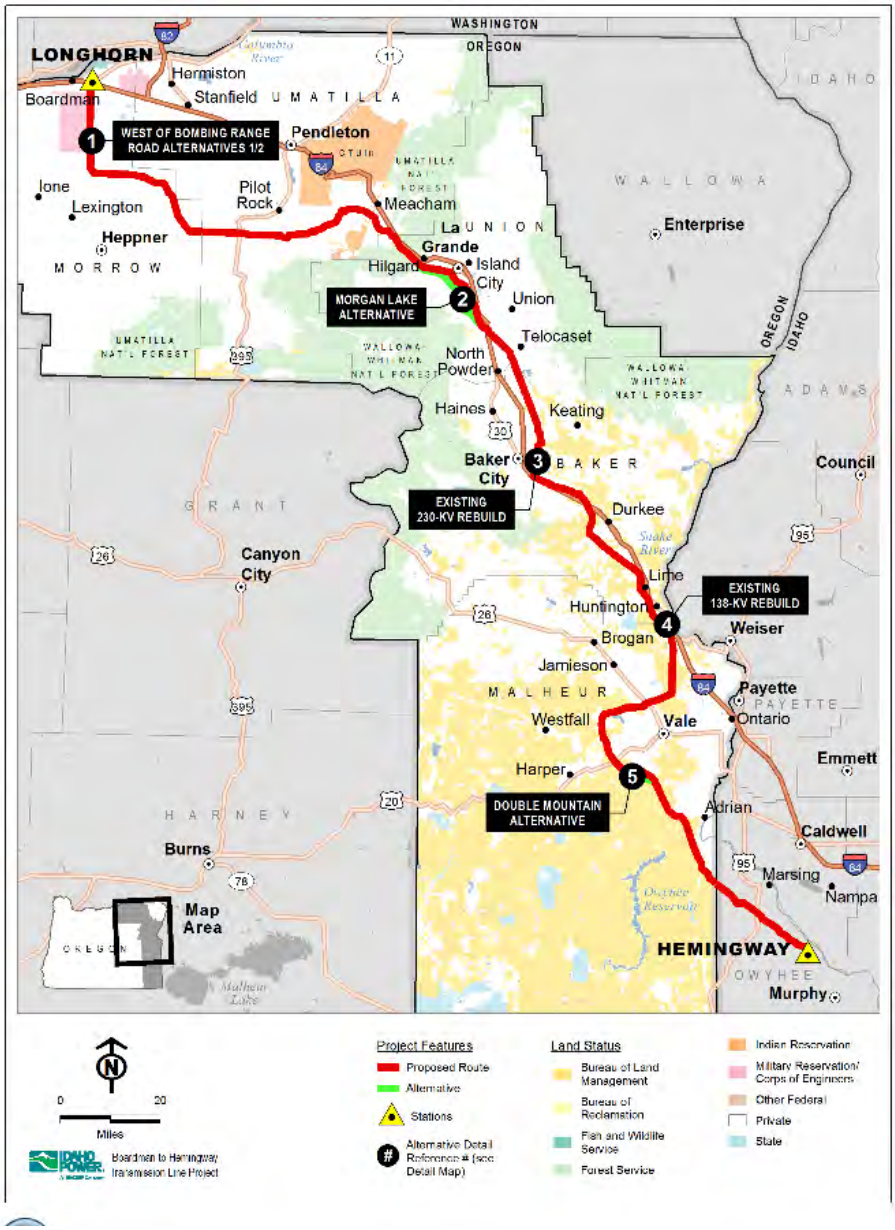

Figure 7. B2H route submitted in 2017 EFSC Application for Site Certificate

B2H Capacity Interest

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

Table 5. B2H joint permit funding capacity interests by funder

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

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

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

Capacity Rating—WECC Rating Process

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

B2H Design

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

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

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

Transmission Line Design

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

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

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

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

Structures are designed to support the phase conductors and shield wires and keep them safely in the air. For the B2H project, structures were chosen to be steel lattice tower structures,

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

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

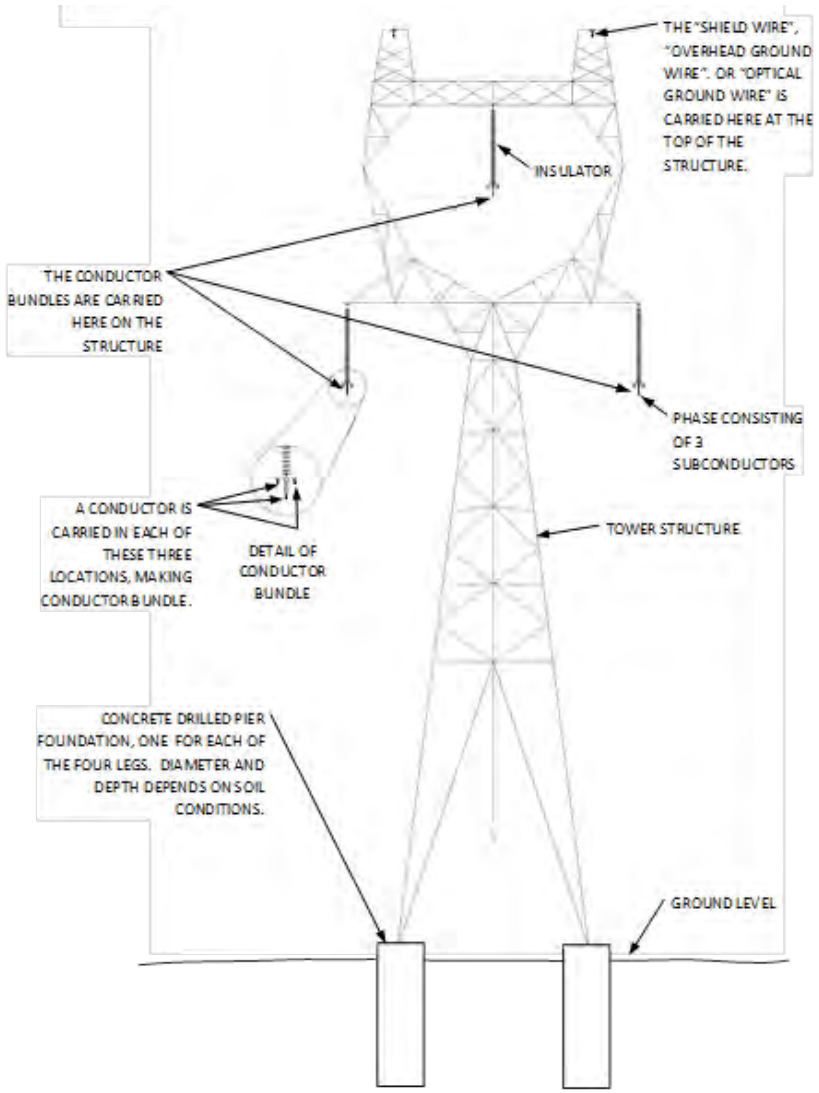

Figure 8. Transmission tower components

Transmission Line Structural Loading Considerations

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

- American Concrete Institute 318—*Building Code Requirements for Structural Concrete*
- American National Standards Institute (ANSI) standards (for material specs)
- American Society of Civil Engineers (ASCE) Manual No.74—*Guidelines for Electrical Transmission Line Structural Loading*

- National Electrical Safety Code (NESC)
- Occupational Safety and Health Administration (OSHA) 1910.269 April 11, 2014 (for worker safety requirements)
- National Fire Protection Association (NFPA) 780—*Guide for Improving the Lightning Performance of Transmission Lines*

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

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

Transmission Line Foundation Design

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

Common industry practices design transmission line structures to withstand wind and ice loads of NESC or greater and are accepted as more stringent than the potential loads resulting from ground motion due to earthquakes. The 2017 NESC Rule 250A4 observes the structure capacity obtained by designing for NESC wind and ice loads at the specified strength requirements is sufficient to resist earthquake ground motions. Additionally, ASCE Manual No. 74 states transmission structures need not be designed for ground-induced vibrations caused by earthquake

motion; historically, transmission structures have performed well under earthquake events,[9, 10] and transmission structure loadings caused by wind/ice combinations and broken wire forces exceed earthquake loads.

Lightning Performance

The B2H project is in an area that historically experiences 20 lightning storm days per year.[11] This is relatively low compared to other parts of the US. The transmission line will be designed to not exceed a lightning outage rate of one per 100 miles per year. This will be accomplished by proper shield wire placement and structure/shield wire grounding to adequately dissipate a lightning strike on the shield wires or structures if it were to occur. The electrical grounding requirements for the project will be determined by performing ground resistance testing throughout the project alignment, and by designing adequately sized counterpoise or using driven ground rods with grounding attachments to the steel rebar cages within the caisson foundations as appropriate.

Earthquake Performance

Experience has demonstrated that high-voltage transmission lines are very resistant to ground-motion forces caused by earthquake, so much so that national standards do not require these forces be directly considered in the design. However, secondary hazards can affect a transmission line, such as landslides, liquefaction, and lateral spreading. The design process considers these geologic hazards using multiple information streams throughout the siting and design process. The current B2H route evaluated geologic hazards using available electronic (geographic information system [GIS]) data, such as fault lines, areas of unstable and/or steep soils, mapped and potential landslide areas, etc. Towers located in potential geologic hazards are investigated further to determine risk. Additional analysis may include field reconnaissance to gauge the stability of the area and subsurface investigation to determine the soil strata and depth of hazard. At the time of this report, no high-risk geologic hazard areas have been identified. If, during the process of final design, an area is found to be high risk, the first option would be to micro-site—route around or span over the hazard. If avoidance is not feasible, the design team would seek to stabilize the hazard. Engineering options for stabilization include designing an array of sacrificial foundations above the tower foundation to anchor the soil or improving the subsurface soils by injecting grout or outside aggregates into the ground. If the geotechnical

[9] 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.

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

[11] USDA RUS Bulletin 1751-801.

investigation determines the problematic soils are relatively shallow, the tower foundations can be designed to pass through the weaker soils and embed into competent soils.

Wildfire

The transmission line steel structures are constructed of non-flammable materials, so wildfires do not pose a physical threat to the transmission line itself. However, heavy smoke from wildfires in the immediate area of the transmission line can cause flashover/arcing between the phase conductors and electrically grounded components. Standard operation is to de-energize transmission lines when fire is present in the immediate area of the line. Transmission lines generally remain in-service when smoke is present from wildfires not in the immediate vicinity of the transmission line. When compared to other resource alternatives, B2H may be more resilient to smoke. For instance, solar PV is susceptible to smoke, which can move into areas even if fires are not in the immediate vicinity of the solar generation. For example, the forest fires in the Pacific Northwest in 2017 caused much smoke along the proposed B2H corridor and in the Pacific Northwest in general. The B2H line would likely still operate for the fires not in the immediate area, whereas solar PV would likely operate at a much-reduced capacity while heavy smoke is covering the area.

Wind Gusts/Tornados

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

Ice

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

Landslide

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

Flood

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

Direct Physical Attack

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

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

B2H Design Conclusions

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

PROJECT CO-PARTICIPANTS

PacifiCorp and BPA Needs

PacifiCorp and BPA are co-participants in the permitting of the B2H project (also referred to as funders). Collectively, Idaho Power, PacifiCorp, and BPA represent a very large electric service footprint in the western US. The fact that three large utilities have each identified the value of the B2H project indicates the regional significance of the project and the value the project brings to customers throughout the West. Idaho Power, PacifiCorp, and BPA have worked closely to assign the capacity rights of the project to correlate with each party's needs. More information about PacifiCorp's and BPA's needs and interest in the B2H project can be found in the following sections.

PacifiCorp

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

PacifiCorp has invested in the permitting of the B2H project because of the strategic value of the B2H corridor, which connects the Pacific Northwest to the Intermountain West. The existing transmission path between the two regions is fully used during key operating periods. As a potential owner in the project, PacifiCorp would be able to use its bidirectional capacity to increase reliability and efficiency for its customers. The following is a list of additional B2H benefits identified for PacifiCorp.

- **Customers**: PacifiCorp continues to invest to meet customers' needs, making only critical investments now to ensure future reliability, security, and safety. The B2H project is identified as an investment that has potential to ensure future reliability, security, and safety for PacifiCorp customers.

- **Renewables**: PacifiCorp continues to grow their renewable resources and transition to a lower-carbon future. The B2H project has been identified as a strategic project that may facilitate PacifiCorp's use the transfer of renewable resources, in addition to other resources, across their PacifiCorp's two balancing authority areas.

- **EIM**: PacifiCorp was a leader in implementing the western energy imbalance market (EIM). The real-time market helps optimize the electric grid, lowering costs, enhancing reliability, and more effectively integrating resources. PacifiCorp believes the B2H

project could help advance the objectives of the EIM and has the potential to benefit PacifiCorp customers and the broader region.

- **Regional Benefit**: PacifiCorp, as a member of the regional planning entity Northern Tier Transmission Group (NTTG), supports the conclusion that the B2H project is as a cost-effective project providing regional solutions to identified regional needs.

- **Balancing Area Operational Efficiencies**: PacifiCorp operates/controls two balancing areas in the West. After the addition of B2H and portions of Gateway West, more transmission capacity will exist between PacifiCorp's two balancing areas, providing the ability to increase operating efficiencies. B2H will provide PacifiCorp 300 MW of additional west-to-east capability and 600 MW of east-to-west capability to move resources between PacifiCorp's two balancing authority areas.

BPA

BPA is a nonprofit federal power marketing administration based in the Pacific Northwest. BPA provides approximately 28 percent of the electric power used in the Pacific Northwest, which has-an estimated population of over 13 million people. BPA also operates and maintains about three-fourths of the high-voltage transmission in its service area. BPA's area includes Idaho, Oregon, Washington, western Montana, and small parts of eastern Montana, California, Nevada, Utah, and Wyoming. For more information, visit bpa.gov.

Similar to the Idaho Power IRP process for identifying cost-effective service alternatives, BPA identified the B2H project plus associated asset exchange as its top priority for pursuit for serving customers in southeast Idaho. BPA's load and resource mix in southeast Idaho results in a net winter peak demand that exceeds the summer peak demand. BPA's winter peak load couples well with Idaho Power's summer peak load to allow for seasonal shaping of the B2H capacity. Seasonal shaping of capacity would allow BPA to own 550 MW of B2H capacity in the winter and 250 MW of capacity in the summer, dramatically increasing the cost-effectiveness of the project for BPA customers. A recent analysis performed by BPA continues to support the B2H project plus the asset exchange as its top priority for pursuit. For more information about the southeast Idaho load service analysis, visit bpa.gov.[12]

As a federal agency, BPA has responsibilities to comply with NEPA and consider the environmental impacts of its actions, such as participating in transmission line construction. To that end, BPA was a cooperating agency in the development of the B2H EIS and continues to coordinate with the BLM and other federal agencies. BPA will ensure an appropriate

[12] Southeast Idaho Load Service analysis: bpa.gov/transmission/CustomerInvolvement/SEIdahoLoadService/Pages/default.aspx

environmental review has been conducted on any BPA-proposed action associated with the project and plans to prepare a ROD to the B2H EIS as appropriate and in accordance with the B2H project's permitting schedule.

Co-Participant Expenses Paid to Date

Approximately $102 million, including allowance for funds used during construction (AFUDC), have been expended on the B2H project through March 31, 2019. Pursuant to the terms of the joint funding arrangements, Idaho Power has received approximately $48 million of that amount as reimbursement from the project participants as of March 31, 2019. Co-participants are obligated to reimburse Idaho Power for their share of any future project permitting expenditures incurred by Idaho Power.

Co-Participant Agreements

Idaho Power, BPA, and PacifiCorp (collectively, the funders) entered a Joint Permit Funding Agreement on January 12, 2012, with the intent to be joint owners of the B2H line. The agreement was amended on February 13, 2018. The Amended and Restated Boardman to Hemingway Transmission Project Joint Permit Funding Agreement provides for the permitting (state and federal), siting, and acquisition of right-of-way (ROW) over public lands.

Related to the project, but not specific to the B2H permitting activities, the B2H co-participants entered into an MOU on January 12, 2012, to 1) explore alternatives to establish BPA eastern Idaho load service from Idaho Power and PacifiCorp's Hemingway Substation and 2) consider whether to replace certain transmission arrangements involving existing assets with joint ownership transmission arrangements and other alternative transmission arrangements pursuant to definitive agreements mutually satisfactory to the co-participants. In other words, in conjunction with the project, the parties agreed to explore cost-effective methods to serve customers by jointly owning facilities other than the B2H project.

COST

Cost Estimate

The total cost estimate for the B2H project is $1 to $1.2 billion dollars, which includes Idaho Power's allowance for funds used during construction (AFUDC). Co-participant AFUDC is not included in this estimate range. The total cost estimate includes a 20-percent contingency for unforeseen expenses.

In IRP modeling, Idaho Power assumes a 21.2-percent share of the direct expenses, plus its entire AFUDC cost, which equates to approximately $292 million. Idaho Power also included costs for local interconnection upgrades totaling $21 million. Notable items that increased the cost relative to the 2017 IRP cost estimate include: increased steel and aluminum estimates, increased labor cost estimates, increased Longhorn substation estimate, and increased AFUDC.

Transmission Line Estimate

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

Substation Estimates

Idaho Power prepared the substation cost estimate for the Hemingway Substation, and BPA prepared the Longhorn Substation estimate. Idaho Power used experience designing and constructing the Hemingway Substation in 2013. The Hemingway Substation is designed to accommodate the B2H line terminal in the future. New equipment must be ordered and installed, but no station expansion will be required. The Longhorn Substation is a station proposed by BPA near Boardman, Oregon. BPA owns the land for the Longhorn Substation, but the station has yet to be constructed. BPA proposed the Longhorn Substation to integrate certain wind projects in the immediate area. BPA has extensive experience designing and constructing substations.

Calibration of Cost Estimates

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

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

Additionally, in early 2017 Idaho Power visited with NV Energy and Southern California Edison to learn from each company's recent experience constructing 500-kV transmission lines in the West. As part of the discussions with each company, Idaho Power calibrated cost estimates and resource requirements.

The two projects were as follows:

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

Costs Incurred to Date

Approximately $102 million, including AFUDC, has been expended on the Boardman-to-Hemingway project through March 31, 2019. Refer to the Co-Participant Expenses Paid to Date section for co-participant reimbursements. The $102 million incurred through March 31, 2019, is included in the $1 to $1.2 billion total estimate. Idaho Power's share of the costs incurred to-date is included B2H IRP portfolio modeling.

Cost-Estimate Conclusions

The cost estimate for B2H has been thoroughly vetted. Idaho Power used third-party contractors with industry experience, relied on PacifiCorp and BPA recent transmission line construction experience, and benchmarked against multiple recent high-voltage transmission line investments in the West to arrive at the B2H construction cost estimate. Material quantities and construction methods are well understood because the B2H project is using BPA's standard tower and conductor design for 500-kV lines. As a conservative measure, Idaho Power has added a 20 percent contingency to cover any unanticipated expenses. As a reminder, Idaho Power's IRP analysis escalates all resource costs at a 2.2-percent inflation rate into the future so future labor and material cost escalations are accounted for in B2H IRP portfolio modeling.

Transmission Revenue

The B2H transmission line project is modeled in AURORA as additional transmission capacity available for Idaho Power energy purchases from the Pacific Northwest. In general, for new

supply-side resources modeled in the IRP process, surplus sales of generation are included as a cost offset in the AURORA portfolio modeling. However, historically, additional transmission wheeling revenue has not been quantified for transmission capacity additions. For the 2017 IRP, Idaho Power modeled the additional transmission wheeling revenue for the B2H project. For the 2019 IRP, Idaho Power considered modeling the additional revenues again, but to be extremely conservative, did not include in the analysis. After the B2H line is in-service, the cost of Idaho Power's share of the transmission line will go into Idaho Power's transmission rate base as a transmission asset. Idaho Power's transmission assets are funded by native-load customers, network customers, and transmission wheeling customers based on a ratio of each party's usage of the transmission system.

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

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

Per the formula above, since transmission costs will likely go up following the installation of B2H, and transmission usage is assumed to remain the same, Idaho Power's transmission rate will increase. Idaho Power's *existing* transmission wheeling customers will pay this higher transmission rate, resulting in incremental transmission revenue to Idaho Power.

Idaho Power believes short-term usage of the Idaho Power transmission system by third parties could increase because additional capacity is created, further reducing Idaho Power customer rates. However, to be conservative, Idaho Power assumed there would be no third-party transmission benefit associated with the B2H project for financial modeling purposes in the 2019 IRP.

Potential BPA and Idaho Power Asset Swap

Corresponding with the construction of B2H, Idaho Power and BPA are working to complete an asset swap that would allow Idaho Power to directly access the Mid-C market and avoid a BPA transmission wheeling charge. Such a swap would result in lower purchased-power prices for Idaho Power's customers. In return, BPA would be able to directly serve their load in southeastern Idaho and avoid an Idaho Power wheeling charge. As part of the 2019 IRP analysis, Idaho Power conservatively assumed there would be a wheeling charge to access Mid-C resources across B2H. If an asset swap were to take place, the cost of energy in B2H portfolios would be further reduced and make B2H an even more attractive project.

BENEFITS

High-voltage transmission lines, such as B2H, are used to serve customer demand and to move energy between major markets hubs in the Western Interconnection. If the existing western US were to be overlaid with thousands of new miles of high-voltage transmission lines, the entire WECC could be optimized such that all customers would be served with the most economic resources at all times of the year. The long-term need for new supply-side resources would greatly diminish due to the vast diversity of the loads and resources across the Western Interconnection. Such a grid, of course, is economically infeasible, but projects such as B2H are being developed to allow economic resources to be shared between regions. The existing transmission grid is not perfect, and many areas of the transmission grid are congested. Transmission congestion causes both economic and reliability issues.

Capacity

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

The Pacific Northwest is a winter peaking region. Pacific Northwest utilities continue to install and build generation capacity to meet winter peak regional needs. Idaho Power operates a system with a summer peak demand. Idaho Power's peak occurs in the late June/early July timeframe, which aligns well with spring hydro runoff conditions when the Pacific Northwest is flush with surplus power capacity. The existing transmission system between the Pacific Northwest and Idaho Power is constrained. Constructing B2H will alleviate this constraint and add 1,050 MW of transfer capability between the Pacific Northwest and Idaho Power (2,050 MW total bi-directionally). Both the Pacific Northwest and Idaho Power will significantly benefit from the addition of transmission capacity between the regions. The Pacific Northwest has already built the power plants and would benefit from selling energy to Idaho Power. Idaho Power needs resources to serve peak load, and a transmission line to existing, underutilized power plants is much more cost effective than building a new power plant.

Avoid Constructing New Resources (and Potentially Carbon-Emitting Resources

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

Table 6 illustrates peak-load estimates, by utility and season, for 2028. The shading represents winter-peaking utilities. As seen in the table, there is significant diversity of load between the regions. The Maximum (MW) column illustrates the minimum amount of generating capacity that would be required if each region were to individually plan and construct generation to meet their own peak load need: 68,000 MW. When all regions plan together, the total generating capacity can be reduced to 64,100 MW, a nearly 6 percent reduction. Transmission connections between the regions, such as B2H, are the key to sharing installed generation capacity.

Table 6. 2028 peak load estimates—illustration of load diversity between western regions

Region	Summer Peak (MW)	Winter Peak (MW)	Maximum (MW)
Avista	2,200	2,400	2,400
BPA	8,400	10,600	10,600
British Columbia	9,700	13,100	13,100
Chelan	300	600	600
Grant	1,200	1,100	1,100
Idaho Power	4,400	3,500	4,400
Nevada	7,600	6,300	7,600
Northwestern Energy	2,000	1,900	2,000
PacifiCorp—East	10,400	8,900	10,400
PacifiCorp—West	3,800	4,000	4,000
Portland General	3,900	3,800	3,900
Puget Sound	3,800	5,300	5,300
Seattle City	1,300	1,600	1,600
Tacoma	600	1,000	1,000
Total	**59,600**	**64,100**	**68,000**

Note: From EEI Load Data used for the WECC 2028 ADS PCM

Load diversity occurs seasonally, as illustrated in Table 6, but it also occurs sub-seasonally and daily. An additional major variable in the Northwest is hydroelectric generation diversity. Over the winter, water accumulates in the mountains through snowpack. As this snow melts, water flows through the region's hydroelectric dams, and northwest utilities generate a significant amount of power. During the spring runoff, generation capacity available in the Pacific Northwest can be significantly higher than in the winter or even late summer. Idaho Power is fortunate to have a peak load that is coincident with the late spring/early summer hydro runoff. Idaho Power's peak load occurs in late June/early July, when hot weather causes major air-conditioning load coincident with agricultural irrigation/pumping load. Idaho Power's time window for a significant peak is quite short, with agricultural irrigation/pumping load starting to ramp down by mid-July.

Utilities have an obligation to serve customer load. This means that utilities are planning to meet peak load needs. As discussed previously, transmission congestion can cause utilities to build additional generation to serve load. In contrast, additional transmission capacity may enable utilities to leverage their transmission system to access generation capacity already constructed by their neighbors. The B2H project is an alternative to building new supply-side resources. As demonstrated in the 2019 IRP, the portfolios that are the most cost-effective, other than B2H portfolios, include new natural gas generation. In this case, B2H provides an alternative to building carbon-emitting supply-side resources.

Improved Economic Efficiency

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

Renewable Integration

Transmission capacity is critical to the integration of renewable generation that, at times, is curtailed due to a lack of transmission capacity to move the energy to load. Transmission is a facilitator for future generation development.

Grid Reliability/Resiliency

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

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

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

2. Loss of the Hemingway–Summer Lake 500-kV line with heavy east-to-west power transfer out of Idaho to the Pacific Northwest. In this disturbance, an existing remedial action scheme (power system logic used to protect power system equipment) will disconnect over 1,000 MW of generation at the Jim Bridger Power Plant to reduce path transfers and protect bulk transmission lines and apparatus. Due to the magnitude of the generation loss, recovery from this disturbance can be extremely difficult. After the addition of B2H, this enormous amount of generation shedding will no longer be required. With two 500-kV lines between Idaho and the Pacific Northwest, the loss of one can be absorbed by the other. Keeping 1,000 MW of generation on the system for major system outages is important for grid stability.

3. Loss of a single 230-kV transmission tower in the Hells Canyon area. Idaho Power owns two 230-kV transmission lines, co-located on the same transmission towers, that connect Idaho to the Pacific Northwest. Because these lines are on a common tower, Idaho Power must consider the simultaneous loss of these lines as a realistic planning event. Historically, such an outage did occur on these lines in 2004 during a day with high summer loads. By losing these lines, Idaho Power's import capability was dramatically reduced, and Idaho Power was forced to rotate customer outages for several hours due to a lack of resource availability. After the addition of B2H, the impact of this outage would be substantially reduced.

Resource Reliability

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

Table 7 provides the NERC TADS data for different transmission operating voltages. From the NERC TADS data, a 300-mile, 500-kV transmission line (B2H) would be expected to have an unexpected forced outage rate of 0.4 percent (line miles / 100 miles x SCOF x MTTR). Stated differently, the B2H transmission line is expected to have 99.6 percent availability when needed.

Table 7. NERC—AC transmission circuit sustained outage metrics

Voltage Class	Circuit Miles	No. of Circuits	No. of Outages	Total Outage Time (hr)	Frequency (SCOF) (per 100 circuit miles per yr)	Frequency (SOF) (per circuit per yr)	MTTR or Mean Outage Duration (hr)
200–299 kV	103,558	4,477.5	876	14,789.6	0.8459	0.1956	16.9
300–399 kV	56,791	1,623.6	394	19,766.8	0.6938	0.2427	50.2
400–599 kV	32,184	594.7	141	3,957.9	0.4381	0.2371	28.1
600–799 kV	9,451	110.0	28	342.4	0.2963	0.2545	12.2
All Voltages	201,985	6,805.8	1,439	38,856.7	0.7124	0.2114	27.0

By comparison, Table 8, lists the average EFOR for traditional fossil fuel power plants (coal, oil, gas, etc.) and the average EFOR for gas power plants.

Table 8. NERC forced-outage rate information for a fossil or gas power plant

Generation Type	Unit Size	EFOR
Fossil (general)	All Sizes	7.96%
Fossil (general)	100–199 MW	7.49%
Fossil (general)	200–299 MW	5.85%
Gas	All Sizes	9.61%
Gas	1–99 MW	9.72%
Gas	100–199 MW	6.85%

A transmission line with a forced outage rate of less than 1 percent is significantly more reliable than a power plant, which has an EFORd of 7 to 10 percent. Of course, a transmission line requires generating resources to provide energy to the line to serve load. However, energy sold as “Firm” must be backed up and delivered even if a source generator fails. Therefore, Firm energy purchases would have an EFORd consistent with the transmission line, which is much more reliable than traditional supply-side generation. In the management of cost and risk, B2H will provide Idaho Power’s operators additional flexibility when managing the Idaho Power resource portfolio.

Reduced Electrical Losses

During peak summer conditions, with heavy power transfers on the Pacific Northwest and Idaho Power transmission systems, the addition of the B2H project is expected to reduce electrical

losses by more than 100 MW in the Western Interconnection. This is a considerable savings for the region; 100 MW of generation, that customers ultimately pay for, does not need produced to supply losses alone.

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

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

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

Flexibility

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

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

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

EIM

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

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

B2H Complements All Resource Types

Utility-scale resource installations allow economies of scale to benefit customers in the form of lower cost per watt. For instance, residential rooftop solar is growing in popularity, but the economics of rooftop solar are outweighed by the economics of utility-scale solar installation.[13] Large transmission lines allow the most economical resources to be sited in the most economical locations. As an example, single-axis tracking utility-scale solar in Salem, Oregon, is expected to have a capacity factor of approximately 15 percent (where the capacity factor is the amount of time the system generates over the course of a year). Comparatively, the same single-axis tracking utility-scale solar system in Boise, Idaho, has a capacity factor of approximately 19 percent[14]. If solar system prices are assumed to be equivalent in Salem and Boise, a Boise installation would generate over 30 percent more energy over the course of the year. Transmission lines provide the ability to move the most economical resources around the region.

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

[13] The National Renewable Energy Laboratory (NREL) estimates the cost of residential rooftop solar (PV) is approximately 2.5 times the cost of utility-scale solar on a $/Watt basis (NREL, U.S. Solar Photovoltaic System Cost Benchmark: Q1 2017).

[14] NREL, System Advisory Model

B2H Benefits to Oregon

Economic and Tax Benefits

The B2H project will result in positive economic impacts for eastern Oregon communities in the form of new jobs, economic support associated with infrastructure development (i.e., lodging and food), and increased annual tax benefits to each county for project-specific property tax dollars. The annual tax benefit for the non-BPA owned portion of the line is shown in Table 9 below. BPA, as a federal entity, does not pay taxes, so BPA's 25 percent project interest is excluded from the estimates. Idaho Power anticipates the project will add about 500 construction jobs, which will provide a temporary increase in spending at local businesses.

Table 9. Projected annual B2H tax expenditures by county*

Oregon County	Property Tax (excluding BPA's 25% ownership interest)
Morrow	$270,295
Umatilla	$569,656
Union	$629,410
Baker	$1,778,282
Malheur	$893,567
Total Oregon Tax Benefit	**$4,141,210**

***The property tax valuation process for utilities is determined differently than locally assessed commercial and residential property. The Oregon Department of Revenue determines the property tax value for Idaho Power Company's ("Idaho Power" or "Company") property (transmission, distribution, production, etc.) as one lump sum value (i.e., not by individual assets)..The Oregon Department of Revenue then apportions and remits Idaho Power's lump sum assessed value to each county. It is from those values that the county generates property tax bills for the Company. Idaho Power converts its Oregon property tax payment by county into an internal rate that can be applied to Idaho Power's transmission, distribution, and production book investment to estimate taxes. This internally calculated tax rate is what was applied to the Boardman to Hemingway ("B2H") estimated book investment (project cost) to estimate property taxes. The table above summarizes the tax value derivation. For estimation purposes, the estimated property taxes are assumed at Idaho Power tax rates. PacifiCorp property taxes may differ from Idaho Power's property taxes. It is Idaho Power's understanding that BPA, as a federal agency, is not obligated to pay taxes on its ownership. Therefore, the total estimated tax amount is discounted by BPA's 25 percent ownership interest.

Local Area Electrical Benefits

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

La Grande and Baker City are served by the Oregon Trails Electric Cooperative (OTEC). Portions of Morrow County and Umatilla County are served by Umatilla Electric Cooperative (UEC) and Columbia Basin Electric Cooperative (CBEC). OTEC, UEC, and CBEC pay BPA's

network transmission rate to receive power and transmission service from the BPA system. If BPA finds less expensive solutions to meet service obligations to customers in southeast Idaho and Wyoming, costs are kept low for other BPA customers, including OTEC, UEC, and CBEC. In other words, BPA customers in Oregon benefit by finding a low-cost solution for customers in Idaho and Wyoming. BPA's financial analysis to date has projected that a share of the B2H project with asset exchange appears the most cost-effective, long-term solution to serve customers in southeast Idaho and eastern Wyoming. Correspondingly, OTEC, UEC, and CBEC customers would also benefit from this cost-effective solution.

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

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

Portions of Baker County are served by Idaho Power, from Durkee to the east. BPA currently provides energy to OTEC, which serves Baker City via transmission connections between the Northwest and Idaho Power's transmission system. At this point, the existing transmission connections between the Northwest and Idaho Power are fully used for existing load commitments, with very little ability to meet load growth requirements. The B2H project will increase the transmission connectivity between the Northwest and Idaho Power by 1,050 MW, which will allow BPA to serve additional demand in Baker City.

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

RISK

Risk is inherent in any infrastructure development project. The sections below address various risks associated with the B2H project. Combining the analysis below with the risk analysis conducted in the 2019 IRP, Idaho Power believes B2H is the lowest-risk resource to meet Idaho Power' resource needs.

Capital-Cost Risk

The capital-cost estimate for the B2H project has been well vetted. See the Cost section for an explanation of how the B2H project cost estimate was determined. Idaho Power's share of the B2H project is $292 million, including Idaho Power's AFUDC. Idaho Power also included costs for local interconnection upgrades totaling $21 million.

The B2H project has considerable capital-cost bandwidth. Idaho Power notes that the B2H capital cost includes a 20 percent cost contingency, which is not included for other resource options considered. Further, to be conservative, Idaho Power did not include potential increases in transmission tariff revenue associated with non-native-load customers' use of the Idaho Power transmission system in the future. Based on NPV analysis over the 20-year planning horizon, Idaho Power's cost share of the B2H project could increase by nearly 50 percent, and the least-cost B2H portfolio would still be more cost-effective than the least-cost, non-B2H portfolio under planning assumptions.

Market Price Risk

Idaho Power performed two separate risk analyses on the 24 resource portfolios developed by the AURORA model for the 2019 IRP. Under the first risk analysis, total portfolio costs (i.e., total of fixed and variable costs) were modeled under three higher-priced natural gas and carbon cost scenarios. The second risk analysis was a stochastic risk analysis, where total portfolio costs were modeled for 20 iterations, or futures, on the following stochastic risk variables: natural gas price, customer load, and hydro condition. These analyses are described in Chapter 9 of the 2019 IRP.

Idaho Power emphasizes that wholesale electric market prices are not specified inputs to the AURORA model, but rather are output by the model in response to various factors and are strongly driven by positive correlations with natural gas price and carbon cost, and a negative correlation with hydro condition. Thus, the risk analyses performed by Idaho Power are considered to study the relative exposure of the IRP resource portfolios to the studied inputs (e.g., natural gas price), and by extension to wholesale electric market prices output by the AURORA model.

The risk analyses performed for the 2019 IRP indicate that total portfolio costs, specifically variable costs associated with the operation of portfolio resources (e.g., cost of imported

wholesale electric energy), are markedly affected by the studied risk variables. For example, the total portfolio costs for Portfolio 14 ranged from $5.1 billion under planning case conditions for natural gas price and carbon cost to $7.8 billion under high case conditions for both inputs (Table 9.3 of 2019 IRP). Similarly, Portfolio 14 costs ranged across the 20 stochastic iterations from $4.8 billion to $6.1 billion (Figure 9.5 of 2019 IRP). Thus, the risk analyses indicate that the studied risk variables strongly influence portfolio costs. However, the analyses also importantly suggest that the relative exposure to the studied risk variables, including by extension wholesale electric market prices, does not dramatically favor one portfolio over another; Portfolio 14 and other B2H-based portfolios exhibit similar ranges in their portfolio costs across the risk scenarios as B2H-alternative portfolios.

Liquidity and Market Sufficiency Risk

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

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

The following data points will address the market sufficiency risk.

Data Point 1. Peak Load Analysis from Table 6

Referencing Table 6 from the Benefits section above, British Columbia and other utilities in the Pacific Northwest[15] have forecast 2028 winter peaks that exceed their forecast 2028 summer peaks by a combined 8,300 MW. Given the difference in seasonal peaks, coupled with Columbia

[15] Load serving entities from Table 6 included in stated figure are Avista, BPA, British Columbia, Chelan, Grant, PacifiCorp—West, Portland General, Puget Sound, Seattle City, and Tacoma.

runoff hydro conditions aligning with Idaho Power's summer peak, resource availability in the Pacific Northwest during Idaho Power's summer peak is likely.

Data Point 2. Pacific Northwest Power Supply Adequacy Assessment for 2023—Northwest Power Conservation Council Report

Idaho Power's review of recent assessments of regional resource adequacy in the Pacific Northwest included the *Pacific Northwest Power Supply Adequacy Assessment for 2023* conducted by the Northwest Power and Conservation Council (NWPCC) Resource Adequacy Advisory Committee (RAAC). The NWPCC RAAC uses a loss-of-load probability (LOLP) of 5 percent as a metric for assessing resource adequacy. The analytical information generated by each resource adequacy assessment is used by regional utilities in their individual IRPs.

The RAAC issued the *Pacific Northwest Power Supply Adequacy Assessment of 2023* report on June 14, 2018,[16] which reports the LOLP starting in operating year 2021 will exceed the acceptable 5 percent threshold and remain above through operating year 2023. Additional capacity needed to maintain adequacy is estimated to be on the order of 300 megawatts in 2021 with an additional need for 300 to 400 MW in 2022. The RAAC assessment includes all projected regional resource retirements and energy efficiency savings from code and federal standard changes but does not include approximately 1,340 MW of planned new resources that are not sited and licensed, and approximately 400 MW of projected demand response.

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

From Idaho Power's standpoint, even with the conservative assumptions adopted in the *Pacific Northwest Power Supply Adequacy Assessment of 2023* report, the LOLP is zero for the critical summer months (see Figure 9). The NWPCC analysis indicates that the region has a surplus in the summer; this is the reason that B2H works so well as a resource in Idaho Power's IRP.

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

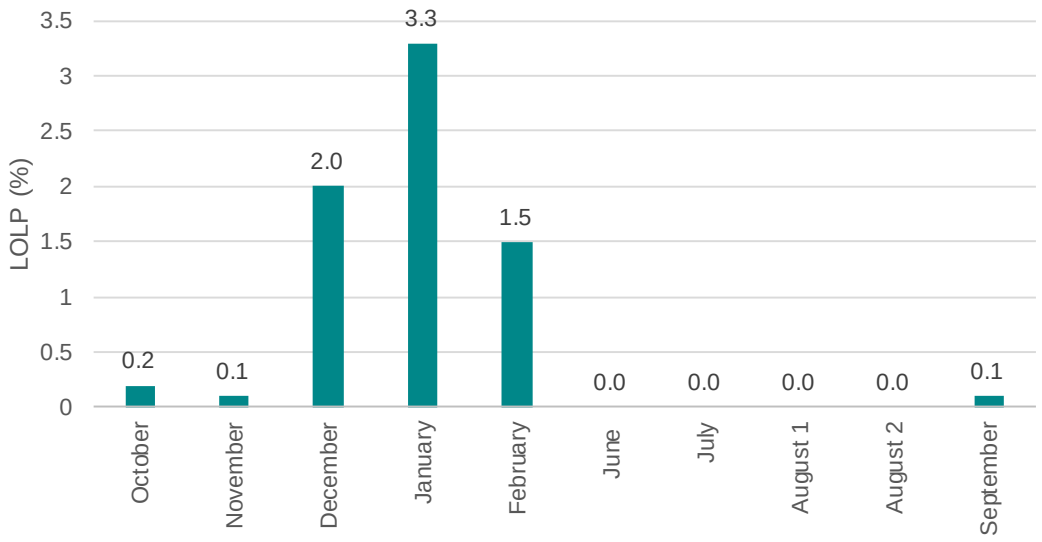

Figure 9. LOLP by month—Pacific Northwest Power Supply Adequacy Assessment of 2023

Data Point 3: 2018 Pacific Northwest Loads and Resources Study—BPA

Idaho Power's review of recent regional resource adequacy assessments also included the *Pacific Northwest Loads and Resources Study* by the BPA (White Book). The most recent BPA adequacy assessment report was released in April 2019 and evaluates resource adequacy from 2020 through 2029.[17] Idaho Power concludes from this analysis that: 1) summer capacity will be available in the future, and 2) additional summer capacity will likely be added as the region adds resources to meet winter peak demand. BPA considers regional load diversity (i.e., winter- or summer-peaking utilities) and expected monthly production from the Pacific Northwest hydroelectric system under the critical case water year for the region (1937). Canadian resources are excluded from the BPA assessment. New regional generating projects are included when those resources begin operating or are under construction and have a scheduled on-line date. Similarly, retiring resources are removed on the date of the announced retirement. Resource forecasts for the region assume the retirement of the following coal projects over the study period:

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

Table 10 Coal retirement forecast

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

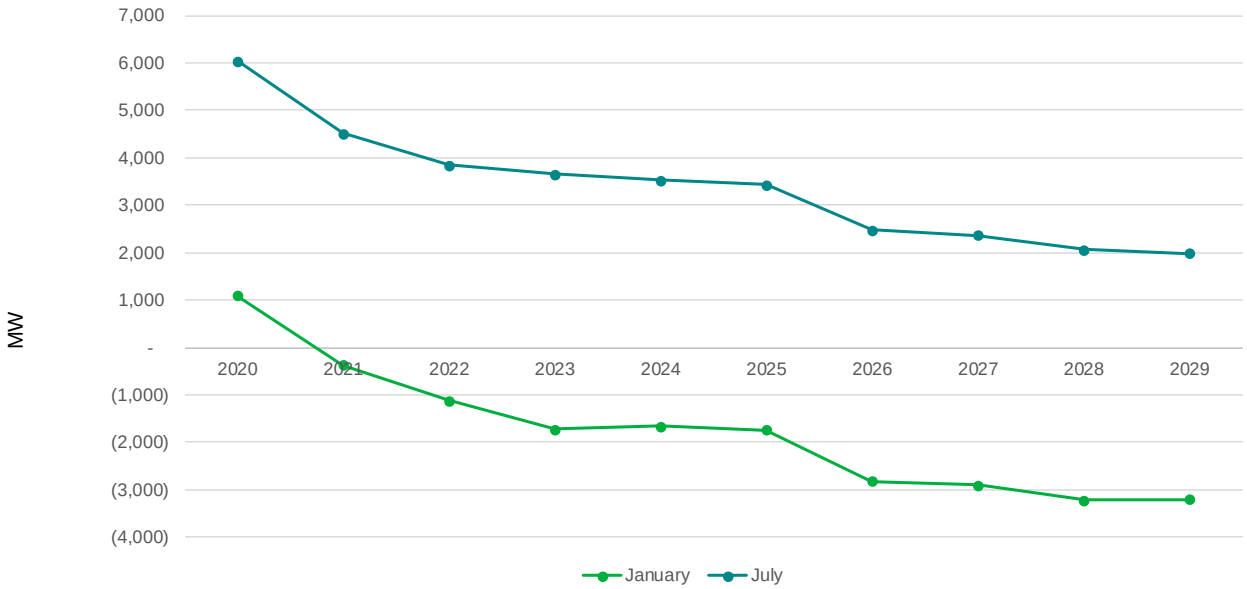

Figure 10. BPA white book PNW surplus/deficit one-hour capacity (1937 critical water year)

Data Point 4: FERC Form 714 Load Data

For illustrative purposes, Idaho Power downloaded peak load data reported through FERC Form 714 for the major Pacific Northwest entities in Washington and Oregon: Avista, BPA, Chelan County PUD, Douglas County PUD, Eugene Water and Electric Board, Grant County PUD, PGE, Puget Sound Energy, Seattle City Light, and Tacoma (PacifiCorp West data was unavailable). The coincident sum of these entities' total load is shown in Figure 11.

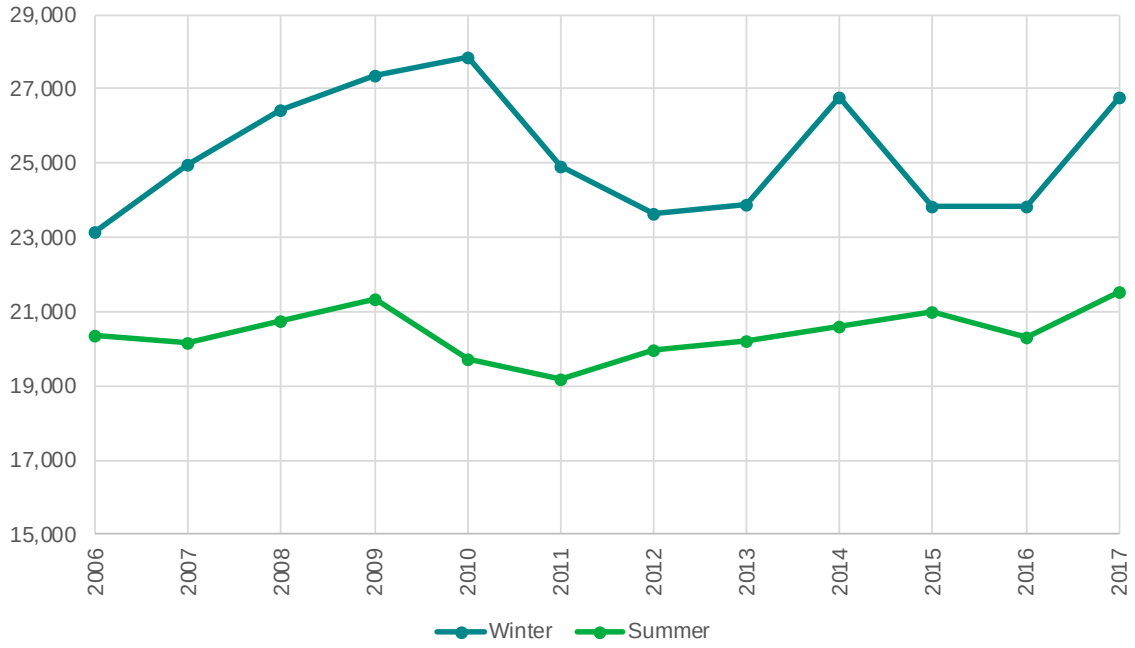

Figure 11. Peak coincident load data for most major Washington and Oregon utilities

Figure 11 illustrates a wide difference between historical winter and summer peaks for the Washington and Oregon area in the region. Other considerations, not depicted, include Canada's similar winter- to summer-peak load ratio (winter peaking), and the increased ability of the Pacific Northwest hydro system in late June through early July compared to the hydro system's capability in the winter (more water in summer compared to winter).

Data Point 5: Northwest and California Renewable Portfolio Standards

The adoption of more aggressive RPS goals by states such as Oregon, California, and Washington will drive policy-driven resource additions. The RPS goals will also likely result in more solar generation throughout the region and may also result in the addition of dispatchable flexible ramping resources, such as the Port Westward 2 power plant installed by Portland General Electric in 2014.

Market Sufficiency and Liquidity Conclusions

Based on the analysis summarized above and in the Markets section of this report, Idaho Power believes there will be sufficient resources in the future to source the B2H transmission line. Also, because the market balances supply and demand based on a market clearing price, liquidity risk can be modeled in economic terms. Should demand be greater than supply at the Mid-C energy hub in the future, market hub prices would reflect the scarcity accordingly (higher prices). As discussed in the Market Price Risk section, risk analyses conducted in the 2019 IRP indicates B2H remains cost competitive over a wide range of risk scenarios, including variations in market prices because of variations in input variables.

Co-Participant Risks

Idaho Power, BPA, and PacifiCorp, collectively referred to as co-participants or funders, are fully engaged in permitting activities. The funders have not yet entered into construction and operating agreements, but they commenced negotiations on those agreements following the Oregon Department of Energy's Draft Proposed Order on May 22, 2019. Per the Amended and Restated Joint Funding Agreement, the funders are allotted up to two 120-day negotiation periods to finalize the construction and operating agreements.

The funders may withdraw from the Joint Permitting Agreement at any time and for no reason, and the withdrawing funder(s) shall pay all costs up to the last day of the month of withdrawal. If one or more of these funders does not move forward with construction, withdrawals from the project, all rights, title, and interest will be transferred to the remaining funder(s) such that the remaining funder(s) shall have 100 percent of the permitting interest in the permitting project. The remaining funders may then seek other funder(s) and/or proceed with construction.

Although funder commitments are not a guarantee at this point, Idaho Power believes other parties may have interest in potential ownership in the project should one or more of the funders decide not to move forward with construction. At least one additional party was involved in the original negotiations that ultimately lead to the current three-party 2012 Joint Funding Agreement. Additionally, Idaho Power has been approached by at least one other entity that may have interest in the B2H project. Any consideration of additional project co-participants would be discussed and agreed on by current funders.

Changes in ownership structure could change cost allocation percentages. Refer to the Capital-Cost Risk section of this appendix for more information about capital-cost risk. For any potential changes in ownership structure, Idaho Power will evaluate the potential ownership cost and capacity allocation, and assuming cost-effective for Idaho Power customers, would request approval from the Oregon and Idaho public utility commissions for any modification in ownership.

Siting Risk

Siting any new infrastructure projects comes with siting risk. The BLM ROD, which was released on November 17, 2017, was a significant milestone in the B2H project development and greatly minimized siting risk by authorizing the project on 85.6 miles of BLM-administered land. The USFS also issued a ROD authorizing the project on National Forest land in 2018, and the Navy is expected to issue a ROD in 2019 authorizing the project on Navy land. The Oregon site certificate process is the next major step in siting, and in 2019, ODOE issued a Draft Proposed Order recommending approval of the project. While the recommendations in the Draft Proposed Order are subject to review and change by EFSC, reaching the Draft Proposed Order stage itself is a major milestone in the state permitting process and the recommendations are certainly

encouraging. Idaho Power believes that the significant progress in both federal and state permitting processes minimizes future siting risk.

Schedule Risk

As of the date of this appendix, Idaho Power has schedule scenarios for B2H in-service dates in 2026 or later. At a high level, remaining activities prior to energization are: permitting, co-participant agreements, preliminary construction, material procurement, and construction.

The permitting phase of the project is ongoing. For federal permitting, the B2H project recently achieved the biggest schedule milestone to date with the release of BLM's ROD on November 17, 2017 and subsequent Right-of-Way Grant in January 2018. The ROD and ROW Grant formalized the BLM-led NEPA process and established a BLM Agency Preferred route on public and private property. The USFS ROD and ROW easement were issued in the first half of 2019. A Navy ROD and easement are the next major federal permitting milestones. At this point, the Navy ROD is not expected to be a critical path schedule activity.

For the State of Oregon permitting process, the B2H project also achieved a considerable milestone in summer 2017 with the submittal of the Amended Application for Site Certificate to the ODOE and an application completeness determination from ODOE in the fall of 2018. The ODOE also issued a Draft Proposed Order in May 2019 and a Final Order and Site Certificate are expected late in 2019. The EFSC permitting process is a critical path schedule activity. Schedule risk exists for the EFSC permitting process if the ODOE does not issue a Site Certificate in 2021.

With the receipt of the BLM ROD and ROW easement, and a Draft Proposed Order from ODOE, sufficient route certainty exists to continue with preliminary construction tasks. In 2019, Idaho Power began the process of acquiring necessary federal authorizations to conduct geotechnical explorations.777 In 2020, Idaho Power plans to initiate the following activities: detailed design, ROW acquisition, LIDAR (aerial mapping), legal surveys, and Geotechnical investigation. The B2H co-participants have not formally decided on the construction contracting method for the project, so the preliminary construction and construction schedule activities remain preliminary until contracts are in place in late 2019. Currently, Idaho Power believes a 2026 in-service date is achievable.

Catastrophic Event Risk

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

Power also keeps a supply of emergency transmission towers that can be quickly deployed to replace a damaged tower, allowing the transmission line to be quickly returned to service.

PROJECT ACTIVITIES

Schedule Update

Permitting

The B2H projected achieved a major milestone with the release of the BLM ROD on November 17, 2017 and the ROW Grant on January 9, 2018. These actions formalized the conclusion of the siting process and federally required NEPA process. The BLM ROD and ROW Grant provides the B2H project the ability to site the project on BLM-administered land. The BLM-led NEPA process took nearly 10 years to complete and involved extensive stakeholder input. Refer to the Project History and Route History sections of this report for more information on project history and public involvement. With the issuance of the USFS ROD and easement, the final step in the federal permitting process is to obtain the Navy ROD and easement. Both the USFS and Navy processes have relied on the BLM's environmental analysis.

For the State of Oregon permitting process, Idaho Power submitted the Amended Application for Site Certificate to the ODOE in summer 2017 and ODOE issued a Draft Proposed Order in May 2019. A Final Order is expected in late 2019.

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

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

Post-Permitting

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

- Geotechnical explorations
- Detailed ground surveys (light detection and ranging (LiDAR) aerial mapping

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

After the Oregon permitting process and preliminary construction activities conclude, construction activities can commence. Construction activities include, but are not limited to, long-lead material acquisition, transmission line construction, and substation construction. The preliminary construction activities must commence several years prior to construction. The material acquisition and construction activities are expected to take 3 to 4 years. The specific timing of each of the preliminary construction and construction activities will be coordinated with the project co-participants.

CONCLUSIONS

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

As discussed in this report, once operational, B2H will provide Idaho Power increased access to reliable, low-cost market energy purchases from the Pacific Northwest. B2H (including early versions of the project) has been a cost-effective resource identified in each of Idaho Power's Integrated Resource Plans (IRP) since 2006 and continues to be a cornerstone of Idaho Power's 2019 IRP preferred resource portfolio. In the 2019 IRP, B2H was identified as the least-cost and least-risk resource to serve future capacity and energy future needs. When compared to other individual resource options, B2H is also the least-cost option in terms of both capacity cost and energy cost. B2H is expected to have a capacity cost that is nearly 60 percent lower than either a combined-cycle gas plant or utility-scale solar alternatives.[18] In addition to the B2H capacity benefits, B2H is expected to have the lowest levelized cost of energy—lower than the expected costs for a combined-cycle gas plant and and utility-scale solar.[19]

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

The company must demonstrate a need for the project before EFSC will issue a Site Certificate authorizing the construction of a transmission line. The need demonstration can be met through a commission acknowledgement of the resource in the company's IRP.[20] In this case, Idaho Power seeks to satisfy EFSC's least-cost plan rule's requirement through an acknowledgement of its 2019 IRP.

[18] 2019 IRP Figure 7.5.

[19] 2019 IRP Figure 7.6

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

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

Table D-1

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

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

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

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

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

Table D-2

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

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

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

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

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

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

Appendix D-2. Detailed list of notable project milestones

- June, 2006 – Idaho Power files the 2006 IRP – Transmission line between Boise and Pacific Northwest identified in preferred resource portfolio (this transmission line eventually became the Boardman to Hemingway project)
- December 19, 2007 – Idaho Power Completes the B2H Preliminary Plan of Development
- 2008 – Idaho Power files the 2008 IRP Update
- August 28, 2008 – Idaho Power submits Notice of Intent to EFSC to submit an Application for Site Certificate.
- September 12, 2008 – Notice of Intent published in the Federal Register for BLM to prepare an Environmental Impact Statement for B2H
- April 10, 2009 – Public Scoping Report for B2H EIS completed by Tetra Tech
- December 30, 2009 – Idaho Power files the 2009 IRP – B2H Project identified in preferred resource portfolio
- June 2010 – Idaho Power completes the B2H Preliminary Plan of Development
- July 2010 – Idaho Power submits a NOI to apply for a Site Certificate for B2H to ODOE
- August 2010 – Idaho Power completes the B2H Siting Study
- August 2010- February 2011 – Idaho Power completes the Community Advisory Process
- February 2011 – Idaho Power completes a Revised Plan of Development for B2H
- June 30, 2011 – Idaho Power files the 2011 IRP – B2H Project identified in preferred resource portfolio
- October 5, 2011 – Obama administration recognizes B2H as one of seven national priority projects that when built, will help increase electric reliability, integrate new renewable energy into the grid, create jobs and save consumers money. See news release.
- November 2011 – Idaho Power completes a Revised Plan of Development for B2H
- January 12, 2012 – Idaho Power, BPA and PacifiCorp enter into Joint Permit Funding Agreement
- March 2, 2012 – ODOE issues a Project Order for B2H

- June 2012 – Idaho Power completes a Supplemental Siting Study for B2H
- October 2, 2012 – BPA identifies B2H as the best option for meeting load growth in southeastern Idaho
- November 27, 2012 – Idaho Power receives formal capacity rating from Western Electricity Coordinating Council (WECC)
- February 28, 2013 – Idaho Power submits Preliminary Application for Site Certificate to Oregon Department of Energy
- June 28, 2013 – Idaho Power files the 2013 IRP
- December 19, 2014 – Draft EIS and Land-use Plan Amendments Published in Federal Register
- December 22, 2014 – ODOE issues amended Project Order for B2H
- June 22, 2015 – Idaho Power submits easement application to Navy to site on Naval Weapons System Training Facility Boardman (aka "Bombing Range")
- June 30, 2015 – Idaho Power files the 2015 IRP – B2H Project identified in the preferred resource portfolio
- November 25, 2016 – BLM issues the Final EIS for B2H
- November 18, 2016 – Idaho Power submits revised application to Navy, updating the route on Navy property based on collaborative routing solution
- January 20, 2017 – Donald Trump inaugurated as 45th President of the United State
- June 29, 2017 – Idaho Power submits electronic version of Amended Preliminary Application for Site Certification to ODOE
- June 30, 2017 – Idaho Power files the 2017 Integrated Resource Plan (IRP) – B2H Project identified in the preferred resource portfolio
- July 19, 2017 – Idaho Power submits hard copies of the Amended Preliminary Application for Site Certification to ODOE.
- November 17, 2017 – The BLM issues a Record of Decision (ROD) for the B2H project. The Record of Decision was signed by the Assistant Secretary of Lands and Minerals, U.S. Department of Interior.

- January 9, 2018 – BLM and Idaho Power sign the BLM ROW Grant for the B2H project.
- September 21, 2018 – ODOE determines the B2H Application for Site Certificate is complete.
- September 28, 2018 – Idaho Power files the Application for Site Certificate with ODOE.
- November 13, 2018 – The US Forest Service issues a Record of Decision for the B2H project
- May 22, 2019 – The Oregon Department of Energy issues a Draft Proposed Order.
- May 28, 2019 – The USFS and Idaho Power sign a ROW easement agreement for the B2H project.
- May 29, 2019 – Bonneville Power Administration issues a Record of Decision for moving an existing 69 kV line from the U.S. Navy bombing range to accommodate the B2H project.