BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S APPLICATION FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE BOARDMAN TO HEMINGWAY 500-KV TRANSMISSION LINE.	)	CASE NO. IPC-E-23-01

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

JARED L. ELLSWORTH

Q. Please state your name, business address, and present position with Idaho Power Company ("Idaho Power" or "Company").

A. My name is Jared L. Ellsworth and my business address is 1221 West Idaho Street, Boise, Idaho 83702. I am employed by Idaho Power as the Transmission, Distribution & Resource Planning Director for the Planning, Engineering & Construction Department.

Q. Please describe your educational background.

A. I graduated in 2004 and 2010 from the University of Idaho in Moscow, Idaho, receiving a Bachelor of Science Degree and Master of Engineering Degree in Electrical Engineering, respectively. I am a licensed professional engineer in the State of Idaho.

Q. Please describe your work experience with Idaho Power.

A. In 2004, I was hired as a Distribution Planning engineer in the Company's Delivery Planning department. In 2007, I moved into the System Planning department, where my principal responsibilities included planning for bulk high-voltage transmission and substation projects, generation interconnection projects, and North American Electric Reliability Corporation's ("NERC") reliability compliance standards. I transitioned into the Transmission Policy & Development group with a similar role, and in 2013, I spent a year cross-training with the Company’s Load Serving Operations group. In 2014, I was promoted to Engineering Leader of the Transmission Policy & Development department and assumed leadership of the System Planning group in 2018. In early 2020, I was promoted into my current role as the Transmission, Distribution and Resource Planning Director. I am currently responsible for the planning of the Company’s wires and resources to continue to provide customers with cost-effective and reliable electrical service.

Q. What is the purpose of your testimony in this case?

A. The purpose of my testimony is to present the need and justification for the Boardman to Hemingway transmission line (“B2H”). The following is a summary of the items I will discuss at length in my testimony:

- As the B2H project entered into the permitting and pre-construction phase, project participants Idaho Power, PacifiCorp, and Bonneville Power Administration (“BPA”), executed a non-binding term sheet (“Term Sheet”) that addresses B2H ownership, transmission service considerations, and asset exchanges. The Term Sheet provides that Idaho Power will acquire a 45.45 percent ownership share of B2H – which reflect an increase of 24.24 percent over the ownership share previously anticipated in the Permit Funding Agreement. This increase results from Idaho Power's acquisition of BPA's 24.24 percent ownership share initially reflected in the Permit Funding Agreement. The Term Sheet reflects that, instead of an ownership interest, BPA will commit to acquiring B2H capacity from Idaho Power through transmission service agreements. The agreements necessary to facilitate Idaho Power's increased ownership share in the B2H project are completed and ready for execution. The Company and PacifiCorp will execute a Construction Funding Agreement that will cover all work necessary to construct the B2H project.

- First identified in the 2006 Integrated Resource Plan ("IRP"), the B2H project has proven to be a cost-effective resource through successive IRPs. The B2H project was identified as part of the preferred resource portfolio in Idaho Power's 2009, 2011, 2013, 2015, 2017, 2019 and most recently in the 2021 IRP.

- The results of the 2021 IRP preferred portfolio indicate the Base with B2H portfolio minimizes both cost and risk, and when compared to the lowest cost non-B2H portfolio, the cost difference definitively shows that the B2H project is a necessary component of the Company's preferred portfolio, assuming comparable risk performance to other portfolios.

- The transmission assumption used in the modeling of the 2021 IRP includes B2H project costs assuming Idaho Power’s 45.45 percent ownership share, which are offset by transmission wheeling revenue benefits associated with B2H.

- Aside from being the least-cost preferred portfolio, the B2H project will provide: (1) improved economic efficiency and renewable integration, (2) grid reliability/resiliency, (3) resource reliability, (4) contingency reserves and reduced electrical losses, and (5) capacity to the Four Corners market hub.

- Idaho Power evaluated B2H project capacity risk, cost risk, and in-service date risk extensively.

Q. Have you prepared any Exhibits?

A. Yes. Exhibit No. 1 is the Term Sheet between Idaho Power, PacifiCorp, and BPA that addresses B2H ownership, transmission service considerations, and asset exchanges. Exhibit No. 2 details the construction, ownership, operation, asset exchanges and service agreements necessary for the Boardman to Hemingway Project. Exhibit No. 3 is BPA’s Tech Forum notice dated January 5, 2023, announcing their completion of B2H project negotiations. Exhibit No. 4 presents Idaho Power’s transmission system. Exhibit No. 5 shows a map of the region with the B2H project substation termination points.

Exhibit No. 6 is the B2H Phase 2 Study Report – Western Electricity Coordinating Council ("WECC") Rating Process. Exhibit No. 7 details the initial branching scenario analysis performed as part of the 2021 IRP.

I. **THE B2H PROJECT PARTICIPANTS**

Q. What entities have participated in funding the permitting of the B2H project?

A. Idaho Power, PacifiCorp, and BPA are parties to the Permit Funding Agreement, initially executed January 12, 2012, and amended several times ("Permit Funding Agreement"), to jointly support the regulatory processes associated with obtaining necessary permits and other work to develop the B2H project ("Parties"). Collectively, the Parties represent a very large electric service footprint in the western United States and have all recognized the regional significance of the B2H project.

Q. What are the key provisions of the existing Permit Funding Agreement?

A. The Permit Funding Agreement is intended to align the Parties' cost responsibility for funding with their assigned B2H capacity allocations. Those allocations include a seasonal capacity arrangement between Idaho Power and BPA – which is a benefit for Idaho Power's customers. Specifically, the agreement provides that Idaho Power's west-to-east share of B2H capacity is 500 MW in the summer season (April-September), and 200 MW in the winter (January-March and October-November) to serve its customers, whereas BPA's west-to-east share is 250 MW in the summer and 550 MW in the winter. Idaho Power and BPA's share of the B2H project make up 750 MW of west-to-east capacity. This seasonal capacity arrangement affords Idaho Power 500 MW of summer season capacity at a cost equivalent to 350 MW, a significant cost-reduction benefit that I will discuss later in my testimony. The synergies between BPA's capacity needs (winter focused) and Idaho Power's capacity needs (summer focused) will lead to high utilization of the B2H project's increased capacity. Finally, the Permit Funding Agreement includes a buyout option, stating that once the B2H project received a Record-of-Decision from the Bureau of Land Management, any party can trigger the Construction Negotiation Phase, and move forward with executing definitive construction funding agreements. If one party chooses not to move forward, the other parties that wish to move forward are required to buy that party out, with the exiting party receiving full compensation for its permitting costs.

Q. What was BPA's interest in the B2H project at the time the Permit Funding Agreement was initially executed?

A. BPA has a load service obligation for its customers spread across southeast Idaho including Lost River Electric, Fall River, Salmon River Electric Cooperative, City of Idaho Falls, City of Soda Springs, and Lower Valley Electric. Starting back in the 1970s, Idaho Power worked with BPA to explore the construction of a 500-kV line from the Pacific Northwest to the Idaho Power area, which would have provided BPA a connection across southern Idaho for BPA to serve its customers (including its south Idaho customers BPA currently serves via Idaho Power transmission). This contemplated line was essentially what B2H is today but was never constructed. Rather than build the line, BPA and PacifiCorp executed a power exchange agreement whereby BPA would deliver power to PacifiCorp customers in the Oregon area, and in exchange, PacifiCorp would deliver power to BPA customers in southeast Idaho. PacifiCorp terminated this agreement, with five-years notice, in 2011. Since 2016, BPA has served its southeast load via combinations of firm transmission across PacifiCorp, conditional firm transmission across Idaho Power, and southern power market purchases. As a result of these events, BPA desired a direct transmission connection, with no transmission wheel, or a single transmission wheel, between the Federal Columbia River Power System and its customers.

Q. What interest in B2H did the Permit Funding Agreement originally anticipate for BPA?

A. Under the Permit Funding Agreement, BPA has a 24.24 percent ownership share. As discussed in more detail later in my testimony, Idaho Power is now planning to acquire BPA's 24.24 percent ownership share of the permit funding.

Q. What was PacifiCorp's interest in the project at the time the Permit Funding Agreement was initially executed?

A. Around the time Idaho Power began permitting the B2H project, the Company and PacifiCorp also began to jointly permit the Gateway West project. Gateway West extends between Hemingway, as the western terminus, and east-central Wyoming, as the eastern terminus. To complement Gateway West and connect its western Balancing Area (PACW) and eastern Balancing Area (PACE) together, PacifiCorp required an additional segment between the Pacific Northwest and Hemingway. The B2H project would provide strategic value to PacifiCorp connecting the two regions, providing bidirectional capacity to increase reliability and enable more efficient use of resources. Under the Permit Funding Agreement, PacifiCorp has a 54.55 percent ownership share.

Q. What other related negotiations did the Parties pursue when executing the Permit Funding Agreement?

A. Coincident with the development of the Permit Funding Agreement, the Parties also executed a Memorandum of Understanding, which detailed high-level parameters of different asset exchanges between Idaho Power, BPA, and PacifiCorp. The asset exchanges, as they are envisioned today, will be discussed later in my testimony.

Q. Have the Parties made progress on final definitive agreements toward project ownership and participation?

A. Yes. Via a revised Permit Funding Agreement, the B2H project is currently in the permitting and pre-construction phase. In addition, on January 18, 2022, and after significant discussions, study efforts, and negotiations, the Parties executed the Term Sheet, included as Exhibit No. 1, that addresses B2H ownership, transmission service considerations, and asset exchanges. The Parties entered into the Term Sheet after over two years of discussions related to next steps associated with the B2H project.

Q. Does the Term Sheet reflect any changes to the ownership arrangements that had been contemplated in the Permit Funding Agreement?

A. Yes. A decade has passed since the Parties signed the Permit Funding Agreement and the Parties' capacity needs, strategies, and goals associated with the B2H project have evolved. As a result, the Parties negotiated the Term Sheet as the framework for future agreements required between and among the Parties as the B2H project moved towards pre-construction. As envisioned under the Term Sheet, BPA will transition out of its role as a joint permit funding coparticipant and will instead rely on the B2H project by taking transmission service from Idaho Power to serve its customers. To accommodate this change, Idaho Power will increase its B2H project ownership share from 21.21 percent to 45.45 percent by acquiring BPA's B2H project capacity.

<u>Idaho Power's Increased B2H Ownership Share</u>

Q. Does the approach agreed to in the Term Sheet maintain the benefits to Idaho Power and its customers of the initially contemplated ownership arrangements?

A. Yes. I will discuss the B2H project's cost effectiveness later in my testimony. In terms of the arrangement with BPA, as previously discussed, BPA and Idaho Power identified synergies associated with each party's B2H capacity needs. BPA needed more winter capacity between the Pacific Northwest and Idaho, and Idaho Power needed more summer capacity. BPA and Idaho Power negotiated the sum of their capacities to fit together like puzzle pieces with total capacity equal to 750 MW. BPA's capacity included 400 aMW (250 MW summer / 550 MW winter) and Idaho Power's capacity included 350 aMW (500 MW summer / 200 MW winter). The new arrangement, whereby BPA purchases transmission service on B2H for the capacity that it had formerly planned to acquire through ownership, maintains the benefits of the B2H project for each party and their customers.

Q. What is the resulting capacity interest following execution of the Term Sheet?

A. Idaho Power's B2H project capacity will increase to 750 MW west-to-east, of which the Company plans to utilize 500 MW in the summer months (April–September) and 200 MW in the winter months (January–March and October-December) for Idaho Power retail customer service, and the remainder will primarily be used to provide BPA network transmission service under Idaho Power's Open Access Transmission Tariff ("OATT") across B2H and southern Idaho. PacifiCorp's B2H ownership interest is not impacted by BPA transitioning out of ownership of the project and their B2H capacity will remain at 300 MW west-to-east and 600 MW east-to-west. There remains 400 MW of unallocated B2H east-to-west capacity, of which 182 MW is expected to be allocated to Idaho Power and 218 MW allocated to PacifiCorp, based on their respective ownership share.

Q. Have the agreements envisioned in the Term Sheet with respect to the Company assumption of BPA's 24.24 percent ownership share of the B2H project come to fruition?

A. Yes. In January 2023, the Parties reached a major project milestone, concluding negotiations on final agreements that memorialize and effectuate the change in ownership. There are five different agreements specific to Idaho Power and necessary to reflect adjustments to the funding and ownership percentages envisioned in the Term Sheet, all of which are nearly finalized and will be ready for execution. They consist of the: (1) Second Amended and Restated B2H Transmission Project Joint Permit Funding Agreement, (2) Network Integration Transmission Service Agreement ("NITSA") for Goshen Load, (3) NITSA for Idaho Falls Load, (4) Purchase, Sale, and Security Agreement, and (5) point-to-point ("PTP") transmission service agreements. These are summarized in Exhibit No. 2 to my testimony and identified as Agreements 1, 2, 3, 4, and 11.

Q. When will the agreements be executed?

A. The parties will execute the agreements following BPA's public process, which is a standard administrative decision-making process applicable to all federal agencies and typically concludes within three months of BPA's notice to the region.

Q. Has BPA begun the public process for their proposed new role in the B2H project?

A. Yes. On January 5, 2023, BPA provided public notice via their Tech Forum platform to customers and stakeholders announcing their completion of B2H project negotiations and releasing the customer engagement schedule, identifying dates for the comment period, customer workshop, and an expected final decision in March 2023. BPA released its Letter to the Region formally opening the comment period on January 9, 2023, providing their customers and stakeholders information about the agreements and notified them of a BPA-hosted workshop on January 23, 2023, to answer questions about the agreements. In addition, BPA explained customers and stakeholders have the opportunity to comment through February 10, 2023, prior to BPA proceeding with execution of the binding contracts for the B2H project. BPA's public process is expected to conclude in March 2023 with the issuance of a letter to the region describing its reasoning behind its decision and responding to comments. A copy of the Tech Forum notice is included as Exhibit No. 3 to my testimony.

Q. What is required of Idaho Power contractually once BPA's ownership share is assumed?

A. As I described earlier, BPA's transition out of its role as a joint permit funding coparticipant will require the Second Amended and Restated B2H Joint Permit Funding Agreement, identified as Agreement 1 on Exhibit No. 2. As contemplated in the Term Sheet, funding and ownership percentages will be adjusted such that the Company will acquire BPA's permitting interest and funding of 45.45 percent of the B2H project costs while providing transmission service across southern Idaho to BPA's customers through NITSA's under Idaho Power's OATT, identified as Agreements 2 and 3 in Exhibit No. 2. In addition, the Company will reimburse BPA over time for the value of the permitting costs paid by BPA.

Q. Will payments received from BPA under the NITSAs reimburse the Company for its increased share of the B2H project?

A. Yes. Based on the yearly load estimates provided by BPA and the resulting forecasted transmission service payments to Idaho Power under the full term of the NITSAs are projected to offset the Company's costs associated with its increased share of the B2H project to support BPA's usage, and, therefore, Idaho Power's customers will not be harmed by the changes to the arrangement. In addition, as an added protection for customers, BPA has agreed to a security and risk backstop payment in conjunction with the purchase and sale provisions associated with the Company's assumption of BPA's ownership share of the B2H project ("Purchase, Sale, and Security Agreement"). The Purchase, Sale, and Security Agreement is included as Agreement 4 to Exhibit No. 2.

Under the Purchase, Sale, and Security Agreement, Idaho Power will hold, as a security payment, an amount equivalent to BPA's investment in the B2H project prior to the transfer of permitting interest to Idaho Power, or the approximately $25 million BPA has paid towards permitting costs to date ("Transferred Permitting Interest"). BPA will also pay Idaho Power an additional $10 million ("Seller's Security"), for a total security deposit of $35 million. The Seller's Security will provide assurances that Idaho Power's retail customers are insulated from risk associated with the Company purchasing BPA's share of the Transferred Permitting Interest.

Upon energization of B2H, interest will accrue on both the Transferred Permitting Interest and the Seller's Security at a rate of [redacted] percent. Because the revenue associated with BPA's usage of B2H in the early years of the agreement will be less than the associated annual revenue requirement, the unreturned portion of the $35 million should mitigate any potential default risk until BPA has fully paid for its share of B2H costs over time.

Q. Please explain why BPA’s payments under the NITSAs will not immediately offset the Company’s costs associated with BPA’s usage of the B2H project.

A. The rate for which BPA will be charged under the NITSAs is based on the network transmission service rates under Attachment H of Idaho Power’s OATT. Rates for transmission service are updated in October of each year, based on the previous calendar year’s actual financial data. Because of the regulatory lag that exists between when transmission costs are incurred and when transmission rates are updated, under recovery of revenue requirement amounts associated with the network transmission service provided to BPA will occur in the first few years the NITSAs are in effect. Once all agreements with BPA have been executed, and prior to energization of the B2H project, the Company will request authorization from the Commission for accounting treatment that will ensure the Company’s retail customers are not harmed by the arrangement and until such time as cumulative network transmission service revenues received from BPA exceed BPA’s cumulative share of the B2H revenue requirement.

Q. Will the Company be responsible for repaying the Transferred Permitting Interest and Seller's Security to BPA?

A. Yes. Repayment of the Seller's Security and all accrued interest related to the Seller's Security will occur within 60 days following energization of B2H. The repayment of the Transferred Permitting Interest plus all related accrued interest will occur starting year eleven following energization of B2H if BPA's total load under the Goshen and Idaho Falls NITSA's for any rolling twelve-month basis averages 400 MW or more prior to the tenth anniversary of energization ("Repayment Event"). Or, in the alternative, if the total load for any rolling twelve-month basis averages 400 MW or more after the tenth anniversary of B2H energization, then the Repayment Event will commence on the next anniversary date of B2H energization.

Q. Are there any additional terms agreed to between Idaho Power and BPA?

A. Yes. The Term Sheet identified other related transactions between the Company and BPA, two were associated with necessary transmission service agreements and one related to substation funding. With respect to the transmission service agreements, first, Idaho Power will secure 500 MW of PTP transmission service from BPA from the Mid-Columbia (Mid-C) hub to the proposed Longhorn substation, which will provide the Company a direct connection to the Mid-C market with flexible long-term BPA wheeling rights. Second, as identified in the Term Sheet and as a component of Agreement 11 in Exhibit No. 2, BPA will redirect its two 100 MW PTP transmission service agreements that it takes from the Company, assigning them to PacifiCorp, a necessary redirect following termination of BPA's existing NITSA with PacifiCorp.

Q. Please describe the agreement required for substation funding.

A. The Parties have also agreed to terms specific to funding of the Longhorn substation, which BPA will own and operate, and where the B2H project interconnects. The Longhorn Substation Funding Agreement, identified as Agreement 8 in Exhibit No. 2, was not required in advance of BPA's public process and has not yet been finalized. However, provisions of the agreement were identified in the Joint Purchase and Sale Agreement ("JPSA") that I will discuss later in my testimony. As a condition precedent to closing of the JPSA, Idaho Power and PacifiCorp must have finalized the agreement between the Parties for funding of a portion of the assets at, and directly adjacent to, the Longhorn substation where B2H will connect. The Longhorn Substation Funding Agreement will also describe the use of a facilities charge, or other similar charge, pursuant to

BPA's OATT, that will be paid by the Company and PacifiCorp allowing for each party to transact across the Longhorn bus in the future. It will detail the ownership, operation and maintenance of the B2H equipment by Idaho Power and PacifiCorp, including (1) a B2H project-related series capacitor at the substation, (2) the B2H project shunt line reactors, and (3) any ancillary equipment required to support the B2H project series capacitor and shunt line reactors.

Q. Are there any other agreements you have not yet discussed necessary for facilitating Idaho Power's increased ownership arrangement with BPA?

A. No.

<u>New Partnership Agreements Necessary for B2H</u>

Q. As partners in B2H, what agreements are necessary between Idaho Power and PacifiCorp?

A. In addition to the transactions directly related to construction and operation of the B2H project, under the Term Sheet the Company and PacifiCorp agreed to the exchange of undivided ownership interests in certain transmission assets to provide transmission capacity that better aligns with the current configuration of the parties' respective future needs following the addition of B2H. The JPSA, included as Agreement 5 in Exhibit No. 2, facilitates these asset exchanges.

Q. How will the asset exchanges between Idaho Power and PacifiCorp facilitate the objectives of the parties as envisioned in the Term Sheet?

A. The Company agreed to exchange with PacifiCorp assets necessary to allow for (1) the transfer to PacifiCorp by Idaho Power of transmission assets between Midpoint and Borah to facilitate 300 MW of west-to-east capacity, (2) the transfer to PacifiCorp by Idaho Power of transmission assets between Borah and Hemingway to enable an additional 600 MW of east-to-west capacity, increasing from the current 1,090 MW to 1,690 MW, (3) the transfer to Idaho Power by PacifiCorp of transmission assets between Populus, Mona, and Four Corners to allow for 200 MW of bi-directional capacity, and (4) the transfer by PacifiCorp to Idaho Power of an ownership interest in identified Goshen area assets.

Four Corners/Populus Assets. The Company’s ownership interest in the Four Corners/Populus assets will include 345-kV transmission lines between the Four Corners, Pinto, Huntington, Camp Williams, Mona, Terminal, 90th South, Ben Lomond, and Populus substations. Consistent with federal processes, the Company and PacifiCorp will complete required studies to determine whether recent system upgrades result in a possible increase in existing transmission capacity between Borah and Populus to facilitate Idaho Power's incremental transfer needs associated with this exchange. If determined necessary, the parties will identify revisions to existing agreements, upgrades, modifications, or other options to meet each party's commercial needs between Borah and Populus.

Goshen Area Assets. Under the Term Sheet, the Parties agreed to make best efforts to plan for service to BPA's six preference customers in Southeast Idaho that requires only one leg of network transmission from the BPA transmission system. Idaho Power's ownership interest in the Goshen area assets will enable BPA to serve its loads currently in PacifiCorp's East transmission with one leg of firm network transmission service from the Company.

Borah/Midpoint West Assets. The transfer by Idaho Power to PacifiCorp of Borah/Midpoint West assets will provide ownership to PacifiCorp on the Company's existing transmission system from Borah/Kinport to Hemingway (east-to-west) and from Midpoint 500 to Borah/Kinport (west-to-east), including 500-kV and 345-kV transmission lines creating a path between the Borah, Kinport, Adelaide, Midpoint and Hemingway substations. In addition, upgrades will be required across the Borah West and Midpoint West paths to facilitate this portion of the proposed asset exchange.

Q. Is Idaho Power requesting approval of these asset exchanges as part of the request in this case?

A. No. The asset exchanges will not be effective until energization of the B2H project which is expected to occur in 2026. Exhibit A to the JPSA does however identify the assets necessary for facilitating the capacity rights agreed upon and acquired by Idaho Power or conveyed to PacifiCorp. Both the Company and PacifiCorp will request approval of the agreement pursuant to *Idaho Code* § 61-328, detailing the benefits associated with the assets being exchanged and demonstrating the transaction is consistent with the public interest, in a future proceeding.

Q. Have Idaho Power and PacifiCorp contemplated who will be responsible for operations and maintenance of the exchanged assets?

A. Yes. PacifiCorp and the Company will expand the existing Joint Ownership and Operating Agreement, as amended and restated August 22, 2019, ("JOOA") to include operation and maintenance provisions associated with the assets acquired by both parties under the JPSA. In addition, the Second Amended and Restated JOOA, identified as Agreement 6 on Exhibit No. 2, will include the ownership, operation, and maintenance provisions associated with the B2H project.

Q. Are there any additional agreements between the Company and PacifiCorp as envisioned under the Term Sheet?

A. Yes. As described in the Term Sheet, the Company and PacifiCorp will execute the B2H Project Joint Construction Funding Agreement ("Construction Funding Agreement") that will cover all work necessary to construct B2H. The Construction Funding Agreement, identified as Agreement 7 on Exhibit No. 2, will provide definitive terms and conditions by which the parties will jointly support and contribute funds, for the procurement, construction, and commissioning of the B2H project, allowing for energization of the project by the earliest in-service date needed by the parties. In addition, it appoints Idaho Power as the construction project manager, providing for full power and authority to do all things necessary or proper to develop and construct the B2H project. Finally, the Construction Funding Agreement will incorporate work associated with the installation of the Midline Series Capacitor substation, which was originally envisioned as a separate funding agreement in the Term Sheet. The Midline Series Capacitor substation is necessary to reduce simultaneous interactions between the NW AC Intertie, central and southern Oregon load service, and Path 14 (Idaho to Northwest). The Company expects to execute the

Construction Funding Agreement with PacifiCorp in July 2023.

Q. Are there any other construction agreements required for the B2H project?

A. Yes. Idaho Power and PacifiCorp will, in conjunction with the JPSA, execute two additional construction agreements, the Midpoint 500/345-kV Transformer Project Construction Agreement ("Midpoint Transformer Construction Agreement") and the Kinport – Midpoint 345-kV Series Capacitor Bank Project Construction Agreement ("Kinport Capacitor Bank Construction Agreement"). Under the Midpoint Transformer Construction Agreement, the Company will make capital upgrades to the Midpoint 500-kV and 345-kV transmission substations, including a second 500/345-kV transformer bank and 345-kV tie line. Capital upgrades will be made to the Midpoint 345-kV transmission line under the Kinport Capacitor Bank Construction Agreement including installation of Kinport-Midpoint 345-kV series capacitor bank. The two construction agreements, identified as Agreements 9 and 10 on Exhibit No. 2, are expected to be executed in March 2023.

Q. Are any changes to transmission service agreements between the Company and PacifiCorp necessary to facilitate the proposed ownership structure of the B2H project?

A. No. While initially contemplated in the Term Sheet, PacifiCorp has determined they will not terminate their existing 510 MW of east-to-west transmission service across southern Idaho as initially anticipated. Rather, as shown on Exhibit No. 2 as Agreement 11, PacifiCorp is expected to continue this existing 510 MW of PTP transmission service from Idaho Power. PacifiCorp's PTP transmission service is term specific, and has roll over rights, so PacifiCorp will continue to reserve its rights to either terminate the service or roll it over. This decision will be made by PacifiCorp every five years. Idaho Power will continue to plan its system assuming PacifiCorp retains their transmission service.

II. TRANSMISSION PLANNING AND THE IRP PROCESS

Q. What is the goal of the IRP?

A. The goal of the IRP is to ensure: (1) Idaho Power's system has sufficient resources to reliably serve customer demand and flexible capacity needs over a 20-year planning period, (2) the selected resource portfolio balances cost, risk, and environmental concerns, (3) balanced treatment is given to both supply-side resources and demand-side measures, and (4) the public is involved in the planning process in a meaningful way. For reliability purposes, in the 2021 IRP the Company planned its resource portfolio to have a Loss of Load Expectation ("LOLE") of

0.05 days per year or better (i.e. less than one resource adequacy related outage event in 20 years).

Q. Please explain the Loss of Load Expectation.

A. The LOLE is a statistical measure of a system's resource adequacy, describing the expected number of days per year that a system would be unable to meet demand. Idaho Power plans to meet a reliability threshold of 0.05 days per year, or better, which represents one resource adequacy related outage event, or less, in 20 years. The Company utilizes test years, based on historical data, to calculate its LOLE. Given Idaho Power's dependence on its hydro system, which fluctuates with water conditions, and the increased frequency of extreme events, the Company has aligned its resource adequacy methodology with the Northwest Power Conservation Council. The calculation of a system LOLE is complex, and not easily input into modeling software, therefore, the Company converts its LOLE methodology into a tabulated load and resource balance for the purposes of long-term planning.

Q. Please explain the "load and resource balance."

A. The load and resource balance is the Company's tabulated plan that identifies resource deficiencies during the 20-year IRP planning horizon. It helps ensure Idaho Power has sufficient resources to meet projected customer demand plus a margin to account for extreme conditions, reserves, and resource outages, and is checked against the LOLE. It is critical when comparing future resource portfolios that each plan achieve at least a base reliability threshold.

Q. How is the resulting resource sufficiency or deficiency determined through the load and resource balance?

A. At a high level, the load and resource balance incorporates the expected availability of Idaho Power's existing resources, comparing the total output to the Company's forecasted load, and illustrates the resulting surplus or deficit by month. This will identify the Company's first resource need date, or the point at which Idaho Power's reliability requirements may not be met.

Q. How is the expected availability of the Company's existing resources determined?

A. The availability of existing resources, including Public Utility Regulatory Policies Act (PURPA) projects, power purchase agreements, hydro, coal, gas, demand response, and market purchases, is determined using a number of factors such as expected stream flows, plant run times, forced outages, historical performance, and transmission import capability, among other considerations.

Q. You indicated this is compared to Idaho Power's forecasted load. How is the load forecast determined?

A. Each year, the Company prepares a forecast of sales and demand for electricity based on a combination of historical system data and trends in electricity usage along with numerous external economic and demographic factors. The anticipated average load and anticipated peak-hour demand forecast represent Idaho Power's most probable outcome for load requirements during the planning period. The difference between the expected availability of the Company's existing resources and the forecasted load is the resulting surplus or deficit by month.

Q. How does the Company address a resource deficiency identified through the load and resource balance analysis?

A. Deficits identified through the formation of the load and resource balance are then used to develop resource portfolios through potential combinations of supply-side resources, such as solar plus storage generation facilities, demand-side resources like energy efficiency measures, and transmission projects that increase access to energy markets. The portfolios are then analyzed and the portfolio that best minimizes cost and risk, and meets the LOLE, is selected in the plan as the preferred portfolio.

Q. Please explain the importance of the Company’s transmission system with regard to resource planning.

A. The Company’s transmission system is a critical component of Idaho Power’s ability to provide reliable and fair-priced energy services. Transmission lines facilitate the delivery of economic resources and allow resources to be sited where most cost effective. Furthermore, geographic diversity of resources and robust connections to neighboring systems facilitate system resiliency and minimize impacts from localized weather or events. For much of its history, Idaho Power has relied upon resources outside of its major load pockets to economically serve its customers. The existing transmission lines between Idaho Power and the Pacific Northwest have been particularly valuable.

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

Therefore, depending on the capacity needs, economics, distance, and intermediate substation requirements, either 230-kV, 345-kV, or 500-kV transmission lines may be chosen as a resource to facilitate the delivery of economic resources. Exhibit No. 4 shows an overview of the Company's high-voltage transmission system.

Q. Please describe the Company's existing transmission capacity between the Pacific Northwest and Idaho Power.

A. Idaho Power owns 1,280 MW of transmission capacity between the Pacific Northwest transmission system and the Company's service territory. Of this, 1,200 MW are on the "Idaho to Northwest" path and 80 MW are on the "Montana-Idaho" path (the Company has transmission rights through Montana to the Pacific Northwest as part of the Amps Agreement – a legacy agreement currently scheduled to expire in 2025). 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 path. To use the Company's share of the Idaho to Northwest capacity to serve customer load, Idaho Power must purchase transmission service from Avista, BPA, or PacifiCorp. Similarly, in order to connect resources in the Pacific Northwest to Idaho Power's transmission system via the Montana-Idaho path, the Company must purchase transmission service from either Avista or BPA to transmit, or wheel, the power across their system and deliver to Idaho Power's transmission system. The Company fully utilizes the capacity of these lines.

Q. Does Idaho Power own any transmission capacity to the south?

A. Yes. The Company owns or controls transmission capacity between utilities in the south via the Idaho – Nevada path with NV Energy, which is utilized to import energy from the North Valmy Power Plant, and the Idaho – Utah path ("Path C") with PacifiCorp. There is no firm transmission availability across Nevada to leverage the Idaho – Nevada path's import capacity to access Desert Southwest markets. Regarding Path C, PacifiCorp is the owner and operator of all Path C transmission lines. Idaho Power has secured 50 MW of transmission capacity across PacifiCorp between the months of June and October to access the Desert Southwest markets.

Q. When did the Company begin analyzing transmission adequacy and/or projects in the IRP?

A. Idaho Power began analyzing transmission adequacy as part of the 2000 IRP. Prior to this time, Idaho Power planned for temporary water-related generation deficiencies through the use of short-term power purchases.

As a summer-peaking utility, short-term power purchases were successful because the majority of other utilities in the Pacific Northwest region experienced peak loads during the winter. Therefore, prior to 2000, Idaho Power's IRPs emphasized acquisition of energy rather than construction of generating resources to satisfy load obligations as transmission constraints were not a major impediment of the Company's purchasing power to meet its service obligations. In addition, IRP planning periods were ten years at the time and therefore significant resource deficiencies did not exist in the ten-year planning period. However, because the Company had started experiencing transmission constraints, coupled with expected renewable resource development in the region, transmission adequacy analyses began being performed as part of the 2000 IRP planning process.

Q. How did Idaho Power analyze transmission adequacy?

A. To better assess the adequacy of the power supply and the transmission system, the Company performed a peak-hour transmission analysis which quantifies the magnitude of off-system market purchases that may be required to serve the load and determines if adequate transmission capacity is available to deliver those purchases. The results of the analysis performed as part of the 2000 IRP indicated transmission deficiencies under low water conditions of approximately 150 MW in 2002, growing to 500 MW by 2009.

Q. Did Idaho Power continue to include transmission planning as part of the IRP preparation?

A. Yes. The results of the 2002 IRP transmission adequacy analysis, under a 90th percentile water and 70th percentile load condition, were July peak transmission deficiencies of 141 MW and 225 MW in 2003 and 2004, respectively, increasing by 75-90 MW per year beginning in 2006, with deficiencies beginning to appear in December and January as well. The results of the 2004 IRP again showed July peaks were expected to increase by approximately 90 MW per year. By 2013, transmission deficiencies began appearing in May through September and reached to nearly 800 MW.

Q. Were any changes made to the 2006 IRP with respect to transmission adequacy?

A. Yes. Beginning with the 2006 IRP, Idaho Power commenced analyzing transmission system constraints for a 20-year planning period. In addition, it was at this time that the transmission analysis began factoring a 95th percentile peak-hour load along with a 90th percentile water and 70th percentile load condition for establishing a capacity target for planning purposes.

Q. How did these refinements impact transmission deficiencies during the 20-year planning period?

A. Deficiencies continued to exist during the summer months throughout the planning period growing from 450 MW in 2011 to as much as 1,800 MW in 2025. As a result, the preferred portfolio selected through the 2006 IRP process, and accepted by the Commission with Order No. 30281, included two significant supply-side resource additions, one of which was 225 MW of additional transmission capacity to occur in 2012 via a connection to the Pacific Northwest power markets, a project at the time envisioned as a 230-kilovolt transmission line between the McNary substation and Boise.

Q. Was this the first time Idaho Power had considered transmission capacity as a supply-side resource addition?

A. Yes, and soon after completion of the 2006 IRP, with Order No. 07-002, the Public Utility Commission of Oregon adopted guidelines regarding integrated resource planning including a guideline specific to transmission:[1]

> 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

[1] *In the Matter of Public Utility Commission of Oregon Investigation into Integrated Resource Planning*, Docket No. UM 1056, Order No. 07-002, pp. 13-14.

> transportation *and electric transmission facilities as resource options* [emphasis added], 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.

Q. How are supply-side resources compared when evaluating costs of resources during the IRP process?

A. When evaluating and comparing alternative resources, two major cost considerations exist: the capital cost of the project, or fixed costs, and the energy cost of the project, or variable costs. Capital costs are derived through cost estimates to install the various projects and energy costs are calculated through a detailed modeling analysis, using the AURORA software, for both transmission capacity and supply-side resource additions. Energy prices are based on forecasted gas prices, coal prices, nuclear prices, hydro conditions, and variable operations and maintenance expenses. Portfolios that include transmission capacity as a resource addition include costs associated with market purchases, as forecasted in the AURORA model.

Q. At what point did the plan for the 230-kV transmission line change to a 500-kV transmission line?

A. Following inclusion of the 230-kV transmission line between the McNary substation and Boise in the preferred portfolio of the 2006 IRP, Idaho Power determined there was insufficient room at the existing McNary substation for major transmission expansion options. In addition, as part of the regional transmission planning public review process conducted by the Northern Tier Transmission Group ("NTTG"), it was determined a 230-kV project would be unable to meet the Company's overall resource planning requirements and would underutilize a substantial transmission corridor. A project operating at a voltage of 500-kV was selected to match the existing Pacific Northwest transmission grid. The resulting project identified to meet this need, the B2H project, is an approximately 300-mile long, overhead, 500-kV high voltage transmission line between the proposed Longhorn Station near Boardman, Oregon, to the existing Hemingway Substation in southwest Idaho, which is designed to increase capacity between the Pacific Northwest and Idaho Power's service area, adding 1,050 MW of capacity to the Idaho to Northwest path in the west-to-east direction, and 1,000 MW of capacity from east-to-west.[2] Exhibit No. 5 shows a map of the region with the B2H project substation termination points.

[2] Beyond the 1,000 MW of east-to-west capacity gained with B2H, the addition of the Gateway West project will further increase the east-to-west capacity between the Pacific Northwest and Idaho Power's service area by approximately 800 - 1,000 MW by mitigating transmission limitations east of Hemingway.

Q. Has the Company evaluated whether alternative transmission arrangements might better serve Idaho Power's need for transmission capacity?

A. Yes. Idaho Power studied a number of alternative transmission additions to determine the best solution to the Company's need. The Company's analysis assumed the 300-mile line between the Longhorn station and the Hemingway station. The following is a summary of relative capacities, anticipated ratings, and losses for new transmission lines at different operating voltages:[3]

Table 1. Comparison of Transmission Line Capacity Scenarios – New Lines from Longhorn to Hemingway

Scenario	**Line Capacity[1]**	**Potential Path 14 W-E 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%

[3] A number of factors impact the transfer capability of transmission lines, including distance, technical design, source/sink capabilities, relative location in the bulk electric system, etc.

[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.

In addition, the Company evaluated the possibility of constructing a new line built in place of an existing transmission line, known as a rebuild, for a portion of the total line length and new line built in a new right-of-way for the remaining portion of the total line length. Every rebuild scenario required at least 136 miles of new construction in a new right-of-way.

Table 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]
a. 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
b. Replace Oxbow - Lolo 230kV 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
c. 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
d. 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
e. Build double circuit 500 kV/230 kV line from McNary to Quartz. Build 500 kV 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 W-E 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 the existing 230-kV right-of-way, each of the scenarios above will require a new ROW to be obtained.

The result of these analyses indicated the only scenarios capable of providing 1,050 MW of west-to-east capacity are new lines at an operating voltage of 500-kV or greater.

Q. Has the capacity of the B2H project received a rating from any other entity?

A. Yes. Early in the B2H project development, the Company coordinated with other utilities in the Western Interconnection via a peer-review 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, and system flow conditions 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, the Company 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. It was determined that the B2H project would add significant reliability, resilience, and flexibility to the Northwest power grid. Exhibit No. 6 to my testimony is the Project Review Group Phase II Rating Report resulting from this study.

Q. Was the B2H project identified as part of the preferred portfolio of subsequent IRPs?

A. Yes. The B2H project was identified as part of the preferred resource portfolio in Idaho Power's 2009, 2011, 2013, 2015, 2017, 2019 and most recently in the 2021 IRP. In addition, the B2H project has been identified as a regionally significant project, producing a more efficient or cost-effective plan in NTTG's 2007, 2009, 2011, 2013, 2015, 2017, and 2019 biennial regional transmission plans, and in the NorthernGrid, NTTG's successor regional planning organization, 2021 biennial regional transmission plan. The B2H project has proven to be a regionally significant project through the regional transmission planning process as well as a cost-effective resource through successive IRPs.

III. THE B2H PROJECT AND THE 2021 IRP

Q. Please describe the process for analyzing resources as part of Idaho Power's most recent IRP, the 2021 IRP.

A. Historically, the Company manually developed portfolios to eliminate resource deficiencies identified in a 20-year load and resource balance. Under this process, Idaho Power developed portfolios that were demonstrated to eliminate the identified resource deficiencies. However, beginning with the Second Amended 2019 IRP, and again with the 2021 IRP, the Company began using AURORA's long-term capacity expansion ("LTCE") modeling capability to develop portfolios.[4]

The logic of the LTCE model optimizes resource additions and exits of generating units based on the performance of each zone defined within WECC and develops resource portfolios under various future conditions, such as sensitivities for natural gas prices, carbon costs, load growth and electrification, transmission and clean energy constraints and timelines. The LTCE model applies a planning margin hurdle and regulation reserve requirements, and then optimizes resource selections around those constraints to determine a least-cost, least-risk portfolio. Available future resources possess a wide range

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[4] Case No. IPC-E-21-43

of operating, development, and environmental attributes. Impacts to system reliability and portfolio costs of these resources depend on future assumptions. Each portfolio consists of a combination of resources derived from the LTCE process to enable Idaho Power to supply cost-effective electricity to customers over the 20-year planning period.

Q. Was any further analysis performed on the portfolios that resulted from the LTCE modeling?

A. Yes. For the 2021 IRP, the Company developed a branching scenario analysis strategy to ensure that the resulting portfolios reasonably identified an optimal solution specific to its customers. Exhibit No. 7 details the initial branching evaluation where Idaho Power compared AURORA-optimized portfolios for a base scenario (i.e., planning conditions for all key inputs such as load growth, natural gas price, carbon price, etc.) for six potential future portfolios. Each of these portfolios was fully optimized by the LTCE model: (1) Base with the B2H project, (2) Base with the B2H project but without Gateway West, (3) Base with the B2H project and PacifiCorp Bridger Alignment, (4) Base without the B2H project, (5) Base without the B2H project and without Gateway West, and (6) Base without the B2H project but with PacifiCorp Bridger Alignment. Idaho Power compared the base portfolios that included the B2H project to determine an optimal B2H project-included portfolio ("Base with B2H") and compared the base portfolios that did not include the B2H project to determine an optimal B2H-excluded portfolio ("Base without B2H PAC Bridger Alignment").

Q. What occurs once the LTCE modeling and robustness testing is complete?

A. Once the portfolios are created using the LTCE model, Idaho Power performs the portfolio cost analysis using the AURORA electric market model, determining operating costs for the 20-year planning horizon for each of the six resource portfolios. The AURORA software applies economic principles and dispatch simulations to model the relationships between generation, transmission, and demand to forecast market prices. Various mathematical algorithms simulate the regional electrical system to determine how utility generation and transmission resources operate to serve load. Portfolio costs are calculated as the net present value ("NPV") of the 20-year stream of annualized costs, fixed and variable, for each portfolio.

Q. What were the results of the AURORA electric market modeling of the six different portfolios?

A. Each of the six different portfolios were evaluated through three different hourly simulations, including the planning case scenario as well as bookends for natural gas and carbon adder price forecasts. The hourly simulations enable the Company to compare how the portfolios will perform throughout the 20-year timeframe and identify a potential option for a preferred portfolio. The following table presents the results of the hourly simulations:

Table 3. 2021 IRP portfolios, NPV years 2021–2040 ($ x 1,000)

Portfolio	Planning Gas, Planning Carbon	Planning Gas, Zero Carbon	High Gas, High Carbon
Base with B2H	$7,942,428	$7,213,486	$9,858,726
Base B2H PAC Bridger Alignment	$8,021,906	$7,175,514	$9,955,484
Base without B2H	$8,219,281	$7,810,996	$9,501,435
Base without B2H without Gateway West[1]	$8,470,101	-	-
Base without B2H PAC Bridger Alignment	$8,207,893	$7,610,787	$9,675,450
Base with B2H—High Gas High Carbon Test[2]	$8,024,064	-	$9,451,660

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

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

This comparison indicates the Base with B2H portfolio best minimizes both cost and risk and is the appropriate choice for the preferred portfolio.

Q. For the portfolios that include the B2H project, do the modeled costs reflect Idaho Power's 45.45 percent ownership share reflected in the Term Sheet and subsequently the Purchase, Sale and Security Agreement?

A. Yes. The 2021 IRP modeled B2H costs based on an Idaho Power ownership share of 45.45 percent.

Q. How did the cost of the Base with B2H portfolio compare to the Base without B2H PAC Bridger

Alignment portfolio as determined through the LTCE modeling?

A. Comparing the NPV cost of the Base with B2H portfolio to the Base without B2H PAC Bridger Alignment portfolio, results in a $266 million difference, or $266 million more costly than the preferred portfolio. This cost difference definitively shows that the B2H project is a necessary component of the Company's preferred portfolio, assuming comparable risk performance to other portfolios.

Q. Did Idaho Power perform any additional testing of the branching scenario analysis?

A. Yes. To further validate transmission planning results, the Company performed additional robustness testing including various sensitivities and scenarios on the portfolios that included the B2H project, including one specific to the robustness of the B2H project, and testing capacity sensitivities, cost risks and timing, which I will describe in more detail later in my testimony. The results of all the sensitivities and scenarios performed validated and further verified that the results of the LTCE modeling identified optimal solutions for Idaho Power's customers.

Q. You indicated the cost of a resource is based on the capacity cost, or fixed costs, and the energy cost, or variable costs of that resource. How did the capacity cost of the B2H project compare to alternative resources when evaluated in the 2021 IRP?

A. The table below provides capital costs for resource options found in the 2021 IRP to have the lowest cost from a capacity perspective:

Table 4. Total capital dollars ($/kW) for select resources considered in the 2021 IRP (2021$)

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

[1] Uses the B2H 750-MW capacity.
[2] Depreciable life assumed for the solar component is 30 years and is 15 years for the storage component.

The capital costs for the B2H project include local interconnection costs and the project is still roughly 70 percent of the cost of the next lowest-cost resource. Additionally, transmission lines, have a longer depreciable life when compared to a gas plant or a solar plant. The low up-front cost and longer depreciation period further reduces the rate impact to Idaho Power's customers. The summation of these factors show the B2H project is the lowest capital-cost resource by a substantial margin.

Q. Has the Company performed any modeling outside of the IRP to test whether Idaho Power's current 45.45 percent ownership share in the B2H project is the most cost effective and least risk option?

A. Yes. Although entirely hypothetical, Idaho Power analyzed alternatives to the ownership structure to evaluate the risk associated with, and cost-effectiveness of, a 45.45 percent ownership share to gauge reasonableness of the modeling results. First, bookends were created using results from the 2021 IRP modeling. As shown in Table 3, the least-cost portfolio without the B2H project, Base without B2H PAC Bridger Alignment, is approximately $8.208 billion and the least-cost portfolio with the B2H project, Base with B2H, has a cost of $7.942 billion, indicating a $266 million difference between the two bookends. Next, the Company modeled an extremely conservative scenario in which there is no value associated with the additional capacity Idaho Power gains through acquisition of BPA's ownership share. That means that even under the highly unlikely scenario where the Company receives no transmission revenues associated with its 45.45 percent ownership share, the B2H portfolio remains the most cost effective and least risk.

Q. What were the resulting portfolio costs?

A. Assuming the unlikely hypothetical scenario results in a portfolio cost of $8.089 billion, indicating that even absent value to the additional capacity Idaho Power will receive with 45.45 percent ownership, the portfolio is still $119 million more cost effective than the lowest cost "without B2H" portfolio. The results indicate that acquisition of BPA's ownership share of the B2H project, with payment from BPA for network transmission service, is the most cost-effective solution for the Company's customers. The B2H project as a resource has repeatedly demonstrated to be the most cost-effective method of serving projected customer demand, and as a transmission line the B2H project also offers incremental ancillary benefits, additional operational flexibility, and access to abundant clean energy in the Pacific Northwest.

IV. THE B2H PROJECT COSTS INCLUDED IN THE PREFERRED PORTFOLIO

Q. What were the B2H project costs included in the 2021 IRP preferred portfolio?

A. The cost estimate included in the 2021 IRP preferred portfolio included B2H project costs assuming Idaho Power's ownership share under the Term Sheet, or 45.45 percent. Prepared between 2020 and 2021, the cost estimate was based on a 10 percent detailed design/indicative design, the best available information at the time. Ms. Barretto will discuss the detailed design/indicative design milestones in more detail in her testimony. The capital costs modeled, including Allowance for Funds Used During Construction but excluding any contingency amounts, were $435.5 million. In addition, the 2021 IRP preferred portfolio included approximately $49.7 million in additional capital costs associated with the B2H project transmission upgrades, [redacted] for local 230-kV upgrades necessary to integrate the project into Treasure Valley load center and an estimated [redacted] associated with the NPV of the buyout of BPA's permitting interest.

Q. How were the B2H project costs determined?

A. The Company contracted with HDR, Inc. ("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.

Q. Were substation costs included in this estimate?

A. Yes. Costs associated with three substations are included in the B2H project cost estimate, the Longhorn station, the Hemingway substation, and a Midline Series Capacitor substation. The northern terminus for B2H requires the new Longhorn station to tap into the existing BPA 500-kV transmission network. BPA owns the land for the Longhorn station and intends to construct the substation, at the request of Umatilla Electric for load service purposes, once all environmental compliance laws are met. As agreed under the Term Sheet, BPA will own all equipment and facilities in the Longhorn station, except B2H-specific equipment and facilities that will be jointly owned by Idaho Power and PacifiCorp. The Company's ownership share of the jointly owned equipment is included in the B2H project costs modeled in the 2021 IRP.

The Idaho Power-owned existing Hemingway substation is designed to accommodate the B2H line terminal but will require the addition of new equipment, which was also included in the total B2H project costs. The Midline Series Capacitor station was added to the project scope between the 2019 IRP and 2021 IRP to facilitate the operational needs of the parties, and at this time consists of only a fenced yard and series capacitor. Finally, the

B2H project costs also include costs associated with necessary local interconnection upgrades, upgrades necessary to the southern Idaho transmission system and BPA’s permitting buyout.

Q. How did the Company calibrate the total B2H project costs for reasonableness?

A. The B2H project costs included in the modeling of the 2021 IRP were reviewed and approved by BPA and PacifiCorp, both of whom have recent 500-kV transmission line construction projects to calibrate against. In addition, Idaho Power worked collaboratively with NV Energy and Southern California Edison to calibrate the B2H project cost estimate using their experience on two recent 500-kV projects.

Q. Transmission capacity can be sold to third parties when not being utilized by the Company. How did Idaho Power model the transmission wheeling revenue benefits associated with B2H?

A. The B2H project is modeled in AURORA as additional transmission capacity available for Idaho Power energy purchases from the Pacific Northwest. In general, for new supply-side resources modeled in the IRP process, surplus sales of generation are included as a cost offset in the AURORA portfolio modeling. Transmission wheeling revenues, however, are not included in AURORA calculations.

To account for this, in the 2021 IRP, Idaho Power modeled incremental transmission wheeling revenue from non-native load customers outside of AURORA as an annual revenue credit. Therefore, the preferred portfolio which includes the B2H project, includes a reduction in project costs associated with incremental transmission revenues, ultimately benefiting the Company's retail customers. The transmission revenue credit incorporates any changes in point-to-point reservations with BPA and PacifiCorp as agreed to under the Term Sheet, including expected revenues from the NITSAs with BPA I discussed earlier in my testimony.

Q. Are there any potential additional benefits in transmission revenues Idaho Power did not include in its quantification?

A. Yes. Due to significant increase in capacity that the B2H project provides to the Idaho to Northwest path, the Company believes firm, short-term firm, and non-firm usage of the Idaho Power transmission system by third parties could increase, as supported by the over 1,000 MWs of transmission requests that the Company has seen across the Idaho to Northwest path over the past 24 months. Additionally, Idaho Power's acquisition of 200 MW of bidirectional capacity to Four Corners, New Mexico will only further enhance the value of the Company transmission system to third parties. These potential revenues would further reduce the cost of the project, however, to be conservative, Idaho Power assumed a constant transmission usage by third parties (no increase or decrease) from an average of usage over recent years.

Q. Did the B2H project costs modeled in the 2021 IRP include a contingency?

A. No. None of the modeled resources in the 2021 IRP included a contingency amount, including the B2H project. Therefore, it would have skewed the IRP modeling results to have included a contingency amount in the B2H cost estimate. That said, the Company did perform a risk analysis in the 2021 IRP for informational purposes in which Idaho Power evaluated 10 percent, 20 percent and 30 percent cost contingencies for the B2H project. The following table presents the B2H project costs, by cost category, and cost contingency utilized in the risk analysis:

Table 5. B2H Project Costs by Cost Contingency

Contingency %	B2H Main Project	Local 230 Upgrades	NPV BPA Permitting Buyout	Total	Total Portfolio NPV Impact
B2H 0%	$435.5M	[redacted]	[redacted]	$485M	$159.6M
B2H 10%	$472.7M	[redacted]	[redacted]	$526M	$178.4M
B2H 20%	$509.8M	[redacted]	[redacted]	$566M	$197.2M
B2H 30%	$546.8M	[redacted]	[redacted]	$607M	$216.1M

The line labeled B2H 0% reflects the costs described earlier and modeled in the 2021 IRP. For IRP purposes, the Company reports Total Portfolio Net Present Value ("NPV")

Impact because this is the amount that must be added to the Preferred Portfolio. The total costs of all resources are levelized into an annual amount, and quantified over the 20-year IRP planning period, for fair comparison purposes. The table below presents the results of the risk analysis that evaluated the various cost contingencies:

Table 6. B2H Cost Sensitivities

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

The 2021 IRP portfolio NPV cost for B2H is $159.6 million assuming a 0 percent contingency amount. B2H with a 30 percent contingency increases the cost of B2H by $122 million ($607 million less $485 million) but that increase only results in increased B2H portfolio costs of $56.5 million NPV. As I mentioned earlier, the difference between the Preferred Portfolio, and the best alternative portfolio that did not include B2H was approximately a $266 million NPV. Additionally, IRPs are based on comparing portfolios, and the best alternative portfolio that did not include B2H included the Gateway West project, another 500-kV transmission project. An increase in B2H costs would likely mean that there would be a comparable increase to Gateway West costs. Therefore, B2H costs could increase significantly, and well beyond 30 percent, and the project would remain cost effective.

Q. Has Idaho Power updated the B2H project cost estimate since publishing the 2021 IRP?

A. Yes. As Ms. Barretto discusses in her testimony, the Company's constructability consultant assisted the Company in updating its B2H project cost estimate. Assuming Idaho Power's 45.45 percent ownership share, B2H project costs are estimated to be [redacted], including a 20 percent contingency. The increase from the 2021 IRP B2H project cost estimate of $485 million can primarily be attributed to (1) increased material and labor costs due to inflation and supply chain issues, and (2) the inclusion of approximately [redacted] in contingency costs, at a total project level, which were not included in the 2021 IRP B2H project costs.

Q. Please explain the increased material and labor costs resulting from inflation and supply chain issues.

A. Inflationary pressures and supply chain disruptions are pushing up the cost of labor and materials necessary to construct B2H. However, transmission expansion is required independent of the portfolio selected to drive least-cost. The least-cost non-B2H portfolio requires a sub-segment of Gateway West in 2027, and another Gateway

West segment in 2033. The cost estimate of these Gateway West segments in the 2021 IRP was based on the estimated cost of B2H, therefore, the cost of the optimal non-B2H portfolio would also increase. In the case of the least-cost non-B2H portfolio, the cost increases associated with Gateway West (assuming the same inflationary and supply chain pressures) would be nearly offsetting when compared to the Preferred Portfolio. Inflationary pressures and supply chain disruptions are therefore immaterial, as the Company must build something to meet its load service requirement, and there is no economic way to avoid a major 500-kV transmission project.

Q. How does the increased B2H cost estimate impact the economics of the project and the conclusions drawn in the 2021 IRP?

A. The following table presents the December 2022 B2H project cost estimate and total portfolio NPV impact together with the 2021 IRP B2H project costs by cost category and cost contingency presented earlier in my testimony in Table 5.

Table 7. B2H Project Costs by Cost Contingency Using Updated Costs

Contingency %	B2H Main Project	Local 230 Upgrades	NPV BPA Permitting Buyout	TOTAL	TOTAL Portfolio NPV Impact
B2H 0%	$435.5M	[redacted]	[redacted]	$485M	$159.6M
B2H 10%	$472.7M	[redacted]	[redacted]	$526M	$178.4M
B2H 20%	$509.8M	[redacted]	[redacted]	$566M	$197.2M
B2H 30%	$546.8M	[redacted]	[redacted]	$607M	$216.1M
2022 B2H Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

While the total B2H cost increases from $485 million (zero percent contingency) to [redacted] (20 percent contingency), the Preferred Portfolio NPV cost impact is only an increase from $159.6 million to [redacted], a [redacted] impact. By inspection, a [redacted] increase does not result in a change to the Preferred Portfolio, as the best non-B2H portfolio is $266 million more costly. And, as I explained earlier in my testimony, the best non-B2H portfolio would see similar increases due to increased Gateway West costs.

In addition, if Idaho Power were to update costs of all capital projects based on current conditions, the B2H project is not the only variable that would change. As I noted above, a primary factor driving the increase in the B2H cost estimate is increased material and labor costs due to inflation and supply chain issues—which would impact the cost of capital projects in all portfolios studied. B2H replacement resources have also seen price increases due to inflationary and supply chain pressures since the 2021 IRP was published, therefore, the least-cost non-B2H portfolio would experience cost increases as well. Even with the cost increase, the Company has sufficient information to ascertain that the B2H project remains the least-cost, least-risk option using the December 2022 updated estimate of [redacted].

V. JUSTIFICATION FOR THE B2H PROJECT

Q. Aside from the B2H project being a component of the least-cost preferred portfolio, what other benefits does the line provide?

A. In a low-carbon future dominated by renewable resources, geographical diversity of wind and solar, as well as regional utility loads, is a vital component of reliability and affordability, and transmission is the enabler of geographical diversity. In-depth studies and experts, such as the American Clean Power Association, cite the need for an expanded and robust transmission system in a decarbonized future.[5] Indeed, the Americans for a Clean Energy Grid highlighted B2H as one of 22 projects that were needed to enable the interconnection of around 60,000 MW of additional renewable capacity in the United States.[6] In addition, a variety of other benefits are expected: capacity to the Four Corners market hub, improved economic efficiency, renewable integration, grid reliability/resiliency, resource reliability, contingency reserves, reduced electrical losses, flexibility, Energy Imbalance Market ("EIM") value, and economic value along the B2H project route.

[7] Slide 20, https://eta-publications.lbl.gov/sites/default/files/lbnl-empirical_transmission_value_study-august_2022.pdf

[7] Slide 20, https://eta-publications.lbl.gov/sites/default/files/lbnl-empirical_transmission_value_study-august_2022.pdf

Improved Economic Efficiency and Renewable Integration

Q. How does the B2H project improve economic efficiency and the integration of renewable resources?

A. Transmission congestion causes power prices on opposite sides of the congestion to diverge as higher cost, less efficient resources are dispatched to ensure the transmission system is operating securely and reliably. Congestion can have a significant cost. Historically, during peak summer conditions, the Idaho to Northwest path in the west-to-east direction often becomes fully constrained with zero firm transmission available between the regions and power prices in Idaho and to the east will generally be higher than power prices in the Pacific Northwest, a market inefficiency caused by inadequate transmission capacity to economically move power between regions. The B2H project will help alleviate this constraint and enable generators in the Pacific Northwest 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. At other times, such as the winter, the roles may reverse with the Pacific Northwest benefiting from economical resources from the Mountain West region with B2H's additional east-to-west capacity.

Similarly, the lack of transmission capacity, at times, prevents the energy from existing renewable generation to move to load, which in turn requires renewable resources to be curtailed. The B2H project is necessary to integrate and balance variable energy resources like wind and solar as it will facilitate the transfer of geographically diverse renewable resources across the western grid and help ensure the clean energy grid of the future, both Idaho Power's and surrounding states', is robust and reliable. Lawrence Berkley National Laboratory recently published a study titled "Empirical Estimates of Transmission Value using Locational Marginal Prices."[7] In the study, the difference between the EIM_BPAHub node and the EIM_UT node (the EIM Utah node is a close surrogate for Idaho Power), has an approximately $13.50 per MWh mean power spread between 2012 and 2022, resulting in approximately $125 million per year in potential energy arbitrage related value. This value, or a subset, was not factored into the 2021 IRP but represents a real benefit to Idaho Power's customers, nevertheless.

Grid Reliability/Resiliency

Q. Please explain how the B2H project will contribute to the reliability and resiliency of the grid.

[7] Slide 20, https://eta-publications.lbl.gov/sites/default/files/lbnl-empirical_transmission_value_study-august_2022.pdf

A. The B2H project will increase the robustness and reliability of the regional transmission system by adding 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.

Q. What are some examples of unexpected disturbances whose impacts would be reduced with the addition of the B2H project?

A. While unexpected disturbances are difficult to predict, I can provide a few examples of disturbances whose impacts would be reduced with the addition of B2H. First, 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 Company’s transmission system can experience. Once the 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 the B2H project, there will be two major 500-kV connections between the Pacific Northwest and Idaho Power, reducing risk by increasing redundancy.

Another potential Idaho Power disturbance could be on the same Hemingway-Summer Lake 500-kV line but east-to-west. In this disturbance, an existing remedial action scheme (power system logic used to protect power system equipment) will disconnect over 700 MW of generation at the Jim Bridger Power Plant or Wyoming wind to reduce path transfers and protect bulk transmission lines and apparatus. Due to the magnitude of the generation loss, recovery from this disturbance can be extremely difficult. After the addition of the B2H project, this sizable amount of generation shedding will no longer be required. With two 500-kV lines between Idaho and the Pacific Northwest, the loss of one can be absorbed by the other. Keeping 700 MW of generation on the system for major system outages is important for grid stability.

Third, the loss of a single 230-kV transmission tower in the Hells Canyon area could create another transmission disturbance. 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 the Company was forced to rotate customer outages for several hours due to a lack of resource availability. With the addition of the B2H project, the impact of this outage would be substantially reduced.

Finally, a more general example is discussed in a recent paper titled "Transmission Makes the Power System Resilient to Extreme Weather" by Grid Strategies[8] which explored the benefits that transmission can provide to regions experiencing extreme weather. During Winter Storm Uri alone, the paper identifies seven different transmission connections that could have provided over $80 million of benefits per 1,000 MW of transmission capacity for that single event, with one specific connection that would have provided nearly $1 billion in benefits per 1,000 MW. Extreme events, such as the 2021 Pacific Northwest heat dome, are seemingly increasing in frequency, and transmission lines provide a significant regional diversity, reliability, and resilience benefit.

Resource Reliability

Q. How does the reliability of a transmission line compare to that of a generation resource?

A. The forced outage rate of a resource is the best measure of its reliability, and, in general, the forced outage rate of transmission lines has historically

[8] https://acore.org/wp-content/uploads/2021/07/GS_Resilient-Transmission_proof.pdf

been lower than traditional generation resources. NERC has historically tracked the forced outage rate for transmission availability through a Transmission Availability Data System ("TADS") and generation availability through a Generation Availability Data System ("GADS").

Q. What are the comparable NERC forced-outage rates of the various resources?

A. The NERC forced-outage rates used in modeling of the 2021 IRP were approximately 6 to 9 percent for coal generation, 3.6 percent for hydro generation, approximately 4.4 percent to 7.3 percent for simple cycle gas generation, 2 percent for combined cycle gas generation and one-quarter of one percent for transmission resources. A transmission line with a forced outage rate of less than 1 percent is significantly more reliable than a power plant - the B2H project is expected to have 99.75 percent availability when needed.

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 equivalent forced outage rate demand – or EFORd - consistent with the transmission line, which is more reliable than traditional supply-side generation. In the management of cost and risk, B2H will provide Idaho Power's operators additional flexibility when managing the Idaho Power resource portfolio. In addition to lower costs, the 2021 IRP preferred portfolio is significantly more reliable than the best portfolio that did not include B2H.

Contingency Reserves and Electrical Losses

Q. How will the B2H project support the Company's contingency reserve obligations?

A. During real-time operations, Idaho Power holds generation in reserve to meet its NERC contingency reserve obligation, or generation in reserve equaling at least three percent of network demand plus three percent of internal generation. For market purchase imports, the three percent contingency requirement for the generation is not borne by the Company but rather the producer in the external balancing area is required to meet the reserve obligation associated with its resource, reducing Idaho Power's reserve obligation.

The Company plans to make additional market purchases with B2H and therefore the selling entity will carry the contingency reserve obligation. This reduction in reserve obligation will offset the additional reserve obligations taken on by the Company through the increased amount of BPA customer network load and generation in the

Idaho Power area. Idaho Power's reserve obligation during summer peak will be reduced with the B2H project as compared to a replacement internal resource.

Q. Is the B2H project expected to reduce electrical losses?

A. Yes. Losses on the power system are caused by electrical current flowing through energized conductors, which in turn create heat. By constructing the B2H project, less efficient, lower voltage transmission lines with very large transfers are relieved, reducing the electrical current through these lines and reducing the losses due to heat.

Q. How did Idaho Power estimate the reduction in electrical losses that is expected to result from addition of the B2H project?

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

To develop an average loss savings benefit for the B2H project that considers all flow hours, regression analysis was performed to develop quadratic equation coefficients that relate path flows to predicted energy loss savings. Next, historical transmission path flows from the previous five years were captured and analyzed with developed loss savings coefficients. The result of the analysis was an Idaho Power 6.4 MW per hour average electrical loss savings with the addition of the B2H project.

Capacity to Four Corners Market Hub

Q. Please explain the value of the capacity gained to the Four Corners Market Hub.

A. As explained earlier in my testimony, under the Term Sheet, Idaho Power will acquire from PacifiCorp transmission assets and their related capacity sufficient to enable the Company to utilize 200 MW of bidirectional transmission capacity between the Company's system, at the Populus substation, and the Four Corners substation, a desert Southwest market hub. Eight entities with transmission have connectivity to the Four Corners market hub. Along the route between Populus and Four Corners, the Company will also have a connection to Mona substation, in central Utah, establishing a direct connection between Idaho Power and the Los Angeles Department of Water and Power. The 200 MW of bidirectional capacity will provide the Company with long-term strategic value from a market that is diverse from the Pacific Northwest. Importantly, the desert Southwest is rich with solar potential which is expected to continue its significant growth in the future, New Mexico has significant wind potential, and the number of desert Southwest entities with a presence at this market hub presents significant market diversity opportunities. Idaho Power believes additional access to this market hub during the winter months will prove to be extremely valuable in a low carbon future.

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

Q. When will the winter value of the Four Corners market access materialize?

A. In the 2021 IRP, the Company expected to start seeing this value in the mid-2030s with winter load increasing, and dispatchable coal resources retiring. As the Company is currently developing its 2023 IRP, however, Idaho Power is seeing the Four Corner's capacity as likely especially valuable in the mid to late-2020s. This change is due to the sizeable increase in the load forecast, and specifically the winter load forecast, due to increased industrial loads.

Q. How has the value of the Four Corners capacity been quantified?

A. In the 2021 IRP, the value of the Four Corner's capacity was not quantified due to its value starting very late in the plan. Generally, the Company did not see any winter reliability issues in its 20-year plan. The Company expects the Four Corners capacity will provide substantial value in its 2023 IRP when portfolios inclusive of B2H and the Idaho Power and PacifiCorp asset exchange are compared against portfolios not inclusive of B2H and the asset exchange. Due to the latest load growth forecasts, winter capacity needs will likely be a key consideration in the development of the 2023 IRP.

Borah West and Midpoint West Capacity Upgrades

Q. What value do the Borah West and Midpoint West upgrades provide?

A. The Borah West and Midpoint West upgrades consist of the addition of a series capacitor to one of the Borah West transmission lines (the 345-kV line between the

Kinport substation and the Midpoint substation), and a new high-voltage transformer added to the Midpoint 500-kV substation. These upgrades are required to facilitate the asset exchange with PacifiCorp, enabling PacifiCorp's usage of its share of B2H project capacity.

In the 2021 IRP, as a conservative estimate, the Company assumed the full $46.8 million cost of these upgrades would be Idaho Power's responsibility. The conservative estimate was chosen because these assets are intended to be utilized to balance the Idaho Power and PacifiCorp asset exchange transaction, and the total values of the assets for each company were unknown. However, subject to final negotiations, it is likely that a portion of these assets will be paid for by PacifiCorp.

Q. Given the capacity being acquired by PacifiCorp, will they continue to take 510 MW of point-to-point transmission service across the Company?

A. Under the Term Sheet, and the Company's 2021 IRP analysis, the expectation was that PacifiCorp would terminate 510 MW of transmission service. PacifiCorp has since indicated their intent to continue to take this service, as is their right as a long-term transmission customer taking PTP service with roll-over rights.

Q. Does PacifiCorp's continued usage of the 510 MW change the decision to move forward with B2H?

A. No. In the 2021 IRP, PacifiCorp terminating the 510 MW of PTP transmission service was evaluated as a cost to B2H due to lost transmission revenue compared to a base "do-nothing" alternative. PacifiCorp continuing to take this PTP transmission service enhances the B2H business case.

Q. What is the trade-off for the Company with PacifiCorp continuing to take 510 MW of transmission service?

A. In the 2021 IRP, the Company was planning to repurpose the transmission that was being used by PacifiCorp to interconnect new resources in Eastern Idaho to be delivered to the growing Treasure Valley area. The impact of the 510 MW transmission service obligation remaining will be evaluated as part of the 2023 IRP.

<u>Additional B2H Project Benefits and Value</u>

Q. Please describe the additional expected benefits and value of the B2H project you have not yet discussed in your testimony.

A. The B2H project provides Idaho Power with flexibility in the acquisition and transfer of generation resources. As advances in technology are driving some generation resources, such as coal plants, toward economic obsolescence, the B2H project serves as an alternative to constructing a new supply-side resource. In this way, B2H reduces the risk of technological obsolescence by ensuring Idaho Power customers always have access to the most economic resources, regardless of the resource type. In addition, because the existing electrical system is so heavily used, new transmission line infrastructure like the B2H project will create additional operational flexibility. The B2H project 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. This additional transmission capacity and operational and resource flexibility also provides value in the EIM and should a day ahead market structure be determined economically beneficial to Idaho Power's customers, the B2H project will complement the Company's market participation and facilitate additional economic benefits.

Q. How will the B2H project provide additional value in the energy imbalance market, or EIM?

A. The expansion of the transmission system, through the addition of the B2H project, will facilitate further benefits by increasing transmission capacity between Idaho Power and other EIM participants. As fluctuations in supply and demand occur for EIM participants, the market system will automatically find the best resources from across the large-footprint EIM region to meet immediate power needs. This activity optimizes the interconnected high-voltage system as market systems automatically manage congestion, helping maintain reliability while also supporting the integration of variable energy resources and avoiding curtailing excess supply by sending it to where demand can use it. Greater transmission transfer capacity between participants in a market reduces congestion costs and allows the lowest cost energy to reach a wider load footprint. Idaho Power views the B2H project as a complement to any resource type. The B2H project will enhance access to the least-cost and most efficient resources and unlock additional regional diversity to benefit the Company as well as all customers in the West.

Q. Will the B2H project provide any economic benefits to the region?

A. Yes. First, the B2H project will result in positive economic impacts for eastern Oregon communities in the form of construction jobs, economic support associated with infrastructure development (i.e., lodging and food), and an estimated increase of $5.8 million in annual tax benefits in total to the counties for project-specific property tax dollars. It will also provide economic development opportunities because it will create available capacity 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 regional benefit to the entire Northwest and specifically benefit load service to eastern Oregon and southern Idaho. It is possible this added capacity resulting from the B2H project could be used to serve additional demand in Union and Umatilla counties.

Portions of Baker County are served by Idaho Power, including the communities of Durkee and Huntington. BPA currently provides energy to Oregon Trails Electric Cooperative ("OTEC"), which serves Baker City via transmission connections between the Northwest and Idaho Power's transmission system. The existing transmission connections between the Northwest and Idaho Power are fully utilized for existing load commitments, with very little ability to meet load growth requirements. The B2H project associated increased transmission connectivity between the Northwest and Idaho Power will allow BPA to serve additional demand in Baker City. Finally, additional transmission capacity can create opportunities for new energy resources, which can add to the county tax base and create new jobs.

Q. Are there any additional benefits you have not discussed?

A. The B2H project will also provide local area electrical benefits. La Grande and Baker City are served by OTEC. Portions of Morrow County and Umatilla County are served by Umatilla Electric Cooperative ("UEC") and Columbia Basin Electric Cooperative ("CBEC"). OTEC, UEC, and CBEC pay BPA's network transmission rate to receive transmission service from the BPA system. As I discussed earlier in my testimony, BPA kicked off a public process related to the B2H project on January 5, 2023, presenting BPA's business case that shows B2H is a cost-effective solution to meet BPA customer needs. Correspondingly, given the sharing of BPA's transmission costs among all of BPA's transmission customers, OTEC, UEC, and CBEC customers would also benefit from this long-term cost-effective solution.

VI. RISK ASSOCIATED WITH THE B2H PROJECT

Q. Are there any risks associated with the B2H project?

A. Risk is inherent in any infrastructure development project. As mentioned earlier in my testimony, as part of the 2021 IRP, Idaho Power evaluated capacity risk, cost risk, and in-service date risk extensively. The capacity risk analysis evaluated the impact on portfolio costs in the event that the Company cannot access the fully expected capacity of B2H. The cost risk was evaluated by performing a tipping point analysis. And finally, the Company evaluated the impacts of a 2027 in-service date, a year later than expected.

Q.   How was the capacity risk analysis performed?

A.   The B2H project capacity evaluation looked at portfolio costs assuming the Company can access 350 MW, 400 MW, 450 MW, 500 MW (equivalent to the preferred portfolio), and 550 MW of capacity. The sensitivities performed with capacity amounts less than 500 MW are set up to evaluate risk related to reduced market access. The 550 MW capacity amount sensitivity quantifies potential benefits associated with leveraging additional market purchases to avoid the need for a new resource. To evaluate the impact of different B2H capacity levels, the Company added or subtracted comparable capacity in the form of battery storage (the least-cost alternative to providing sufficient amounts of capacity) to maintain an adequate planning margin, while maintaining the same cost of B2H to reflect that B2H’s capacity contribution toward the planning margin is reduced with no offsetting cost reduction. The results indicated that even with a substantially reduced planning margin contribution, B2H portfolios remain cost-effective.

Additionally, if Idaho Power is able to access an additional 50 MW from the Mid-C hub, that may present a cost-saving opportunity for customers.[9]

Q. What did the cost risk evaluation conclude?

A. A transmission line such as B2H requires significant planning, organization, labor, and material over a multi-year process to complete and place in-service. Therefore, it is important to evaluate cost risks when planning for such a project. Idaho Power evaluated the cost of the B2H project assuming no contingency, a 10 percent contingency, a 20 percent contingency, and a 30 percent contingency. The results indicated the B2H project would have to increase significantly beyond a 30 percent contingency before the project would no longer be cost-effective, i.e., the tipping point is well beyond a reasonable 30 percent contingency bookend. As I discussed earlier, if the actual costs were to reach these levels, it is likely that other comparable resources, and alternative transmission facilities such as Gateway West, would have their own increases in costs as well.

Q. Please explain the in-service date risk evaluation.

A. The current planned in-service date for B2H is

[9] The B2H project risk analysis can be found in the 2021 IRP Appendix D, pp 63-69.

prior to the summer of 2026, which is necessary to meet the peak demand growth needs. Should the B2H in-service date slip to 2027, other new resources will be required in 2026. Slippage in the schedule from 2026 to 2027 is a possibility and would require new resources, however, as the 2021 IRP preferred portfolio demonstrates, the B2H project remains the most cost-effective long-term resource.

Q.   Were there any additional risk analyses performed with respect to the B2H project?

A.   Yes. Idaho Power also performed a liquidity and market sufficiency risk analysis. As explained earlier in my testimony, the Pacific Northwest is a winter peaking region and Idaho Power operates a system with a summer peak which aligns with the Mid-C hydro runoff conditions when the Pacific Northwest is flush with surplus power capacity. However, the existing transmission system between the Pacific Northwest and the Company is constrained. Constructing the B2H project will alleviate this constraint and add 1,050 MW of total transfer capability between the Pacific Northwest and the Intermountain West region. To evaluate the market sufficiency, Idaho Power assessed five different data points. The first data point was a peak load analysis. British Columbia and other utilities in the

Pacific Northwest[10] have forecast 2030 winter peaks that exceed their forecast 2030 summer peaks by a combined 8,200 MW. Given the difference in seasonal peaks, coupled with Columbia River runoff hydro conditions aligning with the Company's summer peak, resource availability in the Pacific Northwest during Idaho Power's summer peak is highly likely.

For the second data point, the Company reviewed a recent resource adequacy assessment performed by BPA that evaluated resource adequacy from 2021 through 2030.[11] Idaho Power concluded 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. Next, Idaho Power gathered peak load data for the major Pacific Northwest entities in Washington and Oregon to compute the peak coincident load. The results illustrated a wide difference between historical winter and summer peaks.

The fourth data point evaluated the Renewable Portfolio Standard (RPS) goals by states such as California, Oregon and Washington which will drive policy-

[10] Load serving entities from included are Avista, BPA, British Columbia, Chelan, Douglas, Grant, PAC–West, Portland General, Puget Sound, Seattle City, and Tacoma.
[11] BPA. 2019 Pacific Northwest loads and resources study (2019 white book). Technical Appendix, Volume 2: Capacity Analysis. bpa.gov/p/Generation/White-Book/wb/2019-WBK-Technical-Appendix-Volume-2-Capacity-Analysis.pdf. Accessed November 24, 2021.

driven resource additions, and likely result in more solar generation and additional dispatchable flexible ramping resources, such as battery storage. Solar and solar plus storage align very well with summer peak needs, but their value can be limited in the winter months. Meeting winter needs will require the Pacific Northwest region to overbuild these resources above the level to meet a similar summer demand, likely aligning well with the Company looking to access summer energy needs from the market.

Finally, the fifth data point evaluated the potential new resources reported by northwest utilities in their IRPs. The list of resources includes 6,389 MW of planned new resources through 2031. As expected, the Northwest utilities are continuing to plan for growing winter peak demands by adding capacity resources, furthering the depth of the market for the summer season. All data points demonstrate that there will be sufficient market resources in the future to utilize the B2H transmission line.

VII. CONCLUSION

Q. Please summarize your testimony.

A. B2H has been a cost-effective resource identified in each of Idaho Power's IRPs since 2009 and continues to be a cornerstone of Idaho Power's 2021 IRP preferred portfolio. In the 2021 IRP, as has been the case in prior IRPs, the B2H project is not simply evaluated as a transmission line, but rather as a resource that will be used to serve Idaho Power load. That is, the B2H project, and the market purchases it will facilitate, is evaluated in the same manner as a new gas power plant, or a new utility-scale solar plus storage project.

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

The B2H project is nearing its construction phase and project certainty continues to grow. Idaho Power, PacifiCorp, and BPA executed a Term Sheet in early 2022 and have drafted definitive agreements, ready or near ready for signature, associated with the provisions of the Term Sheet. The agreements address the Parties’ capacity needs, strategies, and goals associated with the B2H project. The Company has extensively evaluated the B2H project as a supply-side resource, explored many of the ancillary benefits offered by the transmission line, and considered the risks and benefits of owning a transmission line connected to a market hub in contrast to direct ownership of a traditional generation resource. Once operational, the B2H project will provide Idaho Power increased access to reliable, clean, low-cost market energy purchases from the Pacific Northwest. In addition, 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 benefits in aggregate reflect the B2H project's importance to the Company's commitment to reliability and affordability.

Q. Does this complete your testimony?

A. Yes, it does.

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DECLARATION OF JARED L. ELLSWORTH

I, Jared L. Ellsworth, declare under penalty of perjury under the laws of the state of Idaho:

1. My name is Jared L. Ellsworth. I am employed by Idaho Power Company as the Transmission, Distribution & Resource Planning Director for the Planning, Engineering & Construction Department.

2. On behalf of Idaho Power, I present this pre-filed direct testimony and Exhibit Nos. 1 through 7 in this matter.

3. To the best of my knowledge, my pre-filed direct testimony and exhibits are true and accurate.

I hereby declare that the above statement is true to the best of my knowledge and belief, and that I understand it is made for use as evidence before the Idaho Public Utilities Commission and is subject to penalty for perjury.

SIGNED this 9th day of January 2023, at Boise, Idaho.

Signed:

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-01

IDAHO POWER COMPANY

ELLSWORTH
TESTIMONY

EXHIBIT NO. 1

Contract No. 22TX-17207

TERM SHEET

THIS TERM SHEET IS INTENDED SOLELY TO FACILITATE DISCUSSIONS AMONG IDAHO POWER COMPANY ("***IDAHO POWER***" or "***IPC***"), PACIFICORP ("***PACIFICORP***" or "***PAC***"), AND THE BONNEVILLE POWER ADMINISTRATION ("***BPA***") (EACH REFERRED TO HEREIN AS A "***PARTY***" AND COLLECTIVELY REFERRED TO HEREIN AS THE "***PARTIES***") RELATED TO THE CONSTRUCTION, OWNERSHIP, OPERATION, ASSET EXCHANGES, AND SERVICE AGREEMENTS REGARDING THE BOARDMAN TO HEMINGWAY TRANSMISSION LINE PROJECT ("***B2H PROJECT***" OR "***PROJECT***") AND OTHER TRANSMISSION FACILITIES. EXCEPT FOR SECTION 5 OF THIS TERM SHEET WHICH SHALL BE LEGALLY BINDING UPON THE PARTIES UPON THE EXECUTION AND DELIVERY OF THIS TERM SHEET BY ALL OF THE PARTIES (THE "***EFFECTIVE DATE***"), (I) THIS TERM SHEET IS NOT INTENDED TO CREATE, NOR SHALL IT BE DEEMED TO CREATE, A LEGALLY BINDING OR ENFORCEABLE AGREEMENT OR OFFER, AND (II) NO PARTY SHALL HAVE ANY LEGAL OBLIGATION WHATSOEVER PURSUANT TO THIS TERM SHEET.

1. **BPA Requirements.** The Parties acknowledge and agree that in order to negotiate the Agreements (as defined below) and before BPA can make a definitive final decision regarding whether to enter into the Agreements, BPA must (1) engage in customer and stakeholder outreach, share information about this Term Sheet during the outreach, and solicit feedback; (2) fulfill all requirements under the National Environmental Policy Act (NEPA), the National Historic Preservation Act (NHPA) and other applicable environmental laws, and (3) make a definitive decision in an Administrator's final record of decision. Nothing in this Term Sheet shall be construed as indicating that BPA has engaged in customer and stakeholder outreach; completed its NEPA and other environmental review processes or made a decision regarding how to proceed.

2. **Term.** This Term Sheet shall terminate the earlier of (a) energization of the B2H Project, or (b) execution of all agreements identified in the Term Sheet, or (c) mutual written agreement of all Parties. This Term Sheet may be extended by mutual written agreement of all Parties.

3. **Agreements.** Upon execution of this Term Sheet, the Parties intend to negotiate in good faith toward the execution of the definitive, binding agreements and amendments between or among the Parties described below consistent with the terms and conditions described below ("***Agreements***"). Each of the Parties intends to prepare and deliver to the other Parties initial drafts of the Agreements it is designated as responsible for below by no later than the date identified for each agreement. The Parties further intend, subject

to the BPA requirements in Section 1, that they will endeavor to complete negotiation of and execute the Agreements by no later than the date identified for each agreement; provided, however, that the effectiveness of any such Agreement may be subject to one or more conditions precedent, including state or federal regulatory approvals.

a) Asset Exchanges, Transmission Service Agreements, and Amended and Restated Existing and Future Agreements: The table below defines the transactions contingent on completion of the B2H Project including, without limitation, regulatory approval associated with IPC's acquisition of BPA's interest in the Amended and Restated Boardman to Hemingway Transmission Project Joint Permit Funding Agreement ("Joint Permitting Agreement"), asset exchanges, transmission service agreements, and amended and restated existing and future agreements. Each of the Parties will prepare an initial draft of the Agreements and Amendments below for which it is designated as the Primary Drafter, consistent with the following terms:

	Parties / Agreement / Action / Primary Drafter	***General Terms / Details***
1.	***PAC, BPA*** ***Agreement on Principles and Timelines*** ***Prepare First Draft – BPA: Quarter 2 of Calendar Year 2022*** ***Target Execution Date: Quarter 3 of Calendar Year 2022***	PAC and BPA are parties to the Amended and Restated Midpoint-Meridian Agreement, originally executed June 1, 1994 (the "Midpoint-Meridian Agreement"), which provides PAC with 340 MW of bidirectional scheduling rights over the Buckley-Summer Lake 500kV line (the "Buckley-Summer Lake Line"). In connection with the Goshen Area Asset Exchange (as referenced in Section 3(a)(7) of this table) and the B2H Midline Series Capacitor Project (as referenced in Section 3(a)(12) of this table), PAC and BPA are discussing options to allow PAC the ability to schedule 340 MW from the Buckley substation to the 500kV side of the Ponderosa Transformer Bank 500/230 kV #1 ("Ponderosa 500") and to concurrently schedule 340 MW from the Summer Lake substation to Ponderosa 500 upon energization of the B2H line and the B2H Midline Series Capacitor Project. I. Contingent upon the conditions set forth below, PAC and BPA desire for the concurrent bidirectional scheduling rights over the Buckley-Summer Lake line to be provided as firm point-to-point transmission service ("PTP service") pursuant to the terms and conditions in BPA's Tariff and rate schedules upon energization of the B2H line

		and the B2H Midline Series Capacitor Project. As of the Effective Date, the PAC and BPA understand that such PTP service remains subject to further BPA evaluation. a. BPA's offer of PTP service may include conditions if such conditions are identified during BPA's evaluation. Conditions for PTP service are at BPA's sole discretion and, if required, will be developed consistent with the principles set forth in Section 3(a)(1)(II)(b) so that flows associated with the PTP service over the Buckley-Summer Lake line do not exceed 340 MW in the north-to-south direction and concurrently does not exceed 340 MW in the south-to-north direction during all lines in service. b. As part of the PTP service evaluation, PAC and BPA will also explore options to combine an offer of PTP service with the modification to points of receipt and points of delivery in PAC's existing PTP service tables ("redirect") within the Long Term Firm Point-to-Point Service Agreement (No. 04TX-11722) between PAC and BPA, subject to BPA's Tariff and related business practices including available transfer capability ("ATC"), with a goal to optimize PAC's transmission service over the Federal transmission system to serve its central Oregon loads (*e.g.*, using a single wheel from a network point of receipt to PAC's load at Ponderosa 230 or Pilot Butte 230). BPA will apply its long-standing practice to evaluate the ATC impacts of the new PTP service against the ATC impacts of existing service, to include the bidirectional scheduling rights and redirected service. c. BPA may request additional information from PAC. PAC will make good faith efforts to provide such information within 30 days of BPA's request. d. PAC will submit applicable transmission service request(s) ("TSR") within 30 days

		of BPA's notice to PAC that such requests should be submitted. e. If BPA determines, in its sole discretion, that BPA can convert the bidirectional scheduling rights to PTP service, BPA agrees to offer PTP service pursuant to BPA's Tariff and rate schedules. i. The PTP service will be contingent upon and will not be effective before (A) the energization of the B2H line and the installation of the B2H Midline Series Capacitor Project; (B) approval by the Federal Energy Regulatory Commission ("FERC") of the proposed amendments to the Midpoint-Meridian Agreement discussed in this Section 3(a)(1), per subpart (iii below; and (C) the Goshen Area Asset Exchange set forth in Section 3(a)(7) of this table is completed and all associated agreements are in effect. ii. PAC and BPA will adhere to the applicable requirements set forth in BPA's Tariff and related business practices, including timelines for execution or amendment of a service agreement. iii. Concurrent with the execution of the PTP service agreements contemplated in this Section 3(a)(1)(I), PAC and BPA will amend Section 4(a) of the Midpoint-Meridian Agreement to remove and otherwise terminate PAC's bidirectional scheduling rights over the Buckley-Summer Lake Line. f. If BPA offers PTP service that satisfies PAC's objectives as expressed in this Term Sheet, PAC intends to accept such service subject to the condition regarding FERC approval described below. If following FERC acceptance without material conditions of the arrangements negotiated between BPA and PAC in this Section 3(a)(1)(I), PAC nonetheless fails to submit applicable TSRs or otherwise

		declines to accept the PTP service or execute a PTP service agreement, then BPA will have no further obligations to provide PAC with the PTP service described in this Section 3(a)(1)(I) or the scheduling rights described in Section 3(a)(1)(II) below. g. PAC and BPA will negotiate in good faith to complete and enter into agreements needed to complete the other conditions set forth in Sections 3(a)(2) through (14) and 3(c) of this Term Sheet, as such conditions are applicable to either Party. h. PAC will seek FERC guidance as necessary and file the proposed amendment to the Midpoint-Meridian Agreement with FERC for acceptance. BPA will reasonably coordinate with PAC to prepare for FERC meetings and submissions. FERC's unconditioned acceptance shall be a condition to PAC's obligations as contemplated under this Term Sheet. II. Following either (1) BPA's determination that it is unable to provide the PTP service to PAC consistent with Section 3(a)(1)(I) above, or (2) FERC's failure to accept without material conditions the arrangements negotiated between PAC and BPA under Section 3(a)(1)(I) above, BPA will, effective upon energization of the B2H line and the B2H Midline Series Capacitor Project provided that all conditions described below are met, provide PAC with bidirectional scheduling rights over the Buckley-Summer Lake line which give PAC the ability to (A) schedule 340 MW from the Buckley substation to Ponderosa 500 ("North to South schedules") and (B) concurrently schedule 340 MW from the Summer Lake substation to Ponderosa 500 ("South to North schedules") (collectively referred to as "scheduling limits"). The concurrent, bidirectional scheduling rights described in the immediately preceding sentence will be

		provided pursuant to an amendment to the Midpoint-Meridian Agreement and one or more separately negotiated agreements, that will be effective upon acceptance by FERC and after all conditions set forth in this Section 3(a)(1)(II) are met and will remain in effect until BPA offers PTP service as set forth in Section 3(a)(1)(I). PAC and BPA will work in good faith to satisfy all such conditions consistent with the principles articulated in Section 3(a)(1)(II)(b) below by energization of the B2H line. a. Transmission service to move from the Ponderosa 500 substation. The utilization of the concurrent bidirectional scheduling rights at the Ponderosa substation described in this Section 3(a)(1)(II) is limited to Ponderosa 500. PAC must reserve PTP service from BPA pursuant to BPA's Open Access Transmission Tariff ("OATT"), business practices, and rate schedules in effect at the time of such reservation to move from Ponderosa 500 to the 230 kV side of Ponderosa transformer bank #1 for delivery to PAC load in central Oregon. b. Principles to guide satisfaction of conditions. i. North to South schedules, South to North schedules, and the associated directional power flows may not exceed the scheduling limits (*e.g.*, 340 MW North to South and, concurrently, 340 MW South to North, under all lines in service). A Power Transfer Distribution Factor ("PTDF") based methodology ("PTDF algorithm") and calculator will be used to determine directional power flow. The PTDF algorithm will sum positive flows in the North to South and South to North directions (*i.e.*, schedules and flows are not netted). ii. If, at any time, North to South schedules, South to North schedules, or the associated directional power

		flows exceed the scheduling limits, PAC shall reduce the schedules so that the schedules and directional power flows are within the scheduling limits. BPA can, at BPA's sole discretion, curtail the schedules in whole or in part to maintain the scheduling limits and to mitigate congestion, such as during outages. iii. Schedules (E-Tags) must contain a single granular source and sink. Sources and sinks (1) cannot be consolidated on a single E-Tag; and (2) must be granular enough to determine the PTDF impact. Sources and sinks that are scheduling points, hubs, or nodes are not sufficiently granular to determine the PTDF impact. iv. PAC may not schedule from sources and sinks for which the PTDF impact has not been determined. PAC will provide BPA with advance notice of sources and sinks with sufficient time for BPA to determine the PTDF impact and, if necessary, to accommodate modifications to tools, systems, and contracts. v. The terms, tools, and protocols associated with the concurrent bidirectional scheduling rights will be structured to minimize to the maximum extent possible any impacts exceeding the scheduling limits (*e.g.*, 340 MW North to South and, concurrently, 340 MW South to North, under all lines in service) that the physical flows associated with the concurrent bidirectional scheduling rights have on the Pacific Northwest AC Intertie (as such transmission facilities are defined in the various PNW AC Intertie-related agreements among PAC, BPA and the other PNW AC Intertie owners, the "NW AC Intertie") or the Federal transmission

		system, as reasonably determined by BPA. c. <u>Conditions to Effectiveness of 3(a)(1)(II) Scheduling Rights</u> i. <u>PTDF calculator</u>. BPA will develop a PTDF algorithm to calculate the directional power flow associated with each source and sink that PAC intends to schedule. PAC and BPA will coordinate to develop, at PAC's expense, a PTDF calculator that uses the PTDF algorithm and related communication equipment. ii. <u>Agreement on operational terms</u>. After the PTDF calculator is developed, PAC and BPA will work in good faith to develop operational terms, to include the protocols and requirements for monitoring, dispatch, curtailment, reduction of scheduling limits due to outages, and future modifications to stay current with reliability standards, automation, and technological abilities. The operational terms will remain in effect for the duration of the concurrent bidirectional scheduling rights described in this Section 3(a)(1)(II) and will be incorporated into the proposed amendments to the Midpoint-Meridian Agreement or such other agreement as mutually agreed by PAC and BPA. iii. Energization of the B2H Project, including the B2H Midline Series Capacitor Project. iv. The agreements set forth in Section 3(a)(1)(III) below are, to the extent required, accepted for filing at FERC without material conditions. v. The Goshen Area Asset Exchange set forth in Section 3(a)(7) of this table is completed and all associated agreements are in effect. III. Agreements.

		a. <u>Agreement on Principles and Timelines</u>. Following execution of the Term Sheet, PAC and BPA will negotiate and execute an agreement to reflect the objectives, commitments, principles, conditions, and timelines, including negotiation of applicable follow-on agreements for the PTP service described in Section 3(a)(1)(I), and the concurrent, bidirectional scheduling rights described in Section 3(a)(1)(II). With regard to the concurrent, bidirectional scheduling rights described in Section 3(a)(1)(II), the Agreement on Principles and Timelines would include the principles and conditions set forth in Section 3(a)(1)(II) above, and the timelines for development of the PTDF calculator and negotiation of operational terms and protocols. b. <u>Follow-on Agreements</u>. Before energization of B2H and subject to the conditions described above in this Section 3(a)(1) being met, PAC and BPA will negotiate and execute (1) the agreements and amendments referenced in Section 3(a)(1)(I) above, or (2) if BPA is not yet providing PTP service upon B2H energization consistent with Section 3(a)(1)(I) above, then an amendment to the Midpoint-Meridian Agreement to reflect the addition of the concurrent bidirectional scheduling rights, including term, scheduling and directional power flow requirements, usage of the PTDF calculator, and operational terms, all as consistent with Section 3(a)(1)(II) above. PAC and BPA understand that PAC may be required to file amendments to the Midpoint-Meridian Agreement with FERC for acceptance and that the effective date for the agreements referenced above will be upon FERC acceptance without material conditions. IV. Consistent with the "Phase II Joint Study Report (2020-2021), Boardman to

		Hemingway (B2H) and Incremental Central Oregon Load" completed on March 23, 2021, upon notice from BPA, PAC will upgrade the existing Meridian Series Capacitor on the 500 kilovolt bus or install an electrically equivalent series capacitor on the PAC section of the Dixonville-Meridian-Klamath Falls-Captain Jack lines in southern Oregon within a reasonable time after receiving the notice. PAC shall be responsible for all costs associated with the upgrade. V. PAC and BPA agree that the proposed modifications to the Midpoint-Meridian Agreement described above are limited in scope to PAC's bidirectional scheduling rights over the Buckley-Summer Lake line under Section 4 of the Midpoint-Meridian Agreement and do not include BPA's bidirectional scheduling rights over the Summer-Lake Malin line under Section 4 of the Midpoint-Meridian Agreement. PAC and BPA do not intend to modify, change, alter, or terminate BPA's bidirectional scheduling rights over the Summer Lake-Malin line set forth in Section 4 of the Midpoint-Meridian Agreement or the General Transfer Agreement between PAC and BPA, originally executed May 4, 1982, as amended.
2.	***IPC & PAC & BPA*** ***New operational agreement between IPC, PAC & BPA*** ***Prepare First Draft – BPA: Quarter 3 of Calendar Year 2022*** ***Target Execution Date: Quarter 4 of Calendar Year 2022***	IPC, PAC and BPA agree to negotiate in good faith and draft a tri-party operational agreement that will: a. Consider Midpoint-Meridian Agreement Section 5(f); and b. Define the curtailment procedures between NW AC Intertie, Western Electricity Coordinating Council (WECC) Path 14 (Idaho to Northwest), and WECC Path 75 (Hemingway – Summer Lake); and c. Identify conditions for revising the tri-party operational agreement including, but not limited to: i. Engagement with NW AC Intertie partners;

		ii. In the event the B2H Project and the B2H Midline Series Capacitor Project are not complete and energized by 2027. The Parties will make best efforts to negotiate and target execution of the tri-party operational agreement within one year of the Effective Date of this Term Sheet, with an effective date for the tri-party operational agreement a reasonable time thereafter.
3.	***PAC & BPA*** ***Termination of Existing NITSAs:*** ***PAC Trans – BPA Merchant NITSAs (SA Nos. 746, 747)*** ***Incorporate into Agreement on Principles and Timelines under 3(a)(1)***	BPA Network Integration Transmission Service Agreements ("NITSAs") (PacifiCorp Service Agreement No. 746 and No. 747): BPA and PAC agree to terminate the aforementioned NITSAs upon (1) the completion of the asset purchase and sale between IPC and PAC as detailed in Section 3(a)(5) through Section 3(a)(7) of this table – the Goshen Area Asset Exchange, and (2) the commencement of network service as described in Section 3(b)(1).
4.	***IPC & BPA & PAC*** ***New Agreement:*** ***Longhorn Substation Agreements*** ***Prepare First Draft – BPA: Quarter 2 of Calendar Year 2022*** ***Target Execution Date: Quarter 3 of Calendar Year 2022***	IPC and PAC will fund a portion of the proposed Longhorn substation near Boardman, Oregon, if B2H interconnects at Longhorn. This funding will occur as specified in one or more negotiated Longhorn Substation Agreements between the Parties that is consistent with BPA's Line and Load Interconnection Business practices and allows for recovery of the network portion of these funds through incremental transmission wheeling revenue. The agreement will: a. include provisions for IPC and PAC to pay a use of facilities charge or other charge pursuant to BPA's OATT and applicable rate schedules to transact across the Longhorn bus in the future; b. include provisions for IPC and PAC to potentially own, operate and maintain B2H equipment, which shall include: the

		B2H series capacitor at Longhorn, the B2H shunt line reactors at Longhorn, any ancillary equipment required to support those devices, such as switches, bypass breakers (series cap), and insertion breakers (shunt reactor); and c. be contingent upon BPA completing its obligations and responsibilities under NEPA, NHPA, and other requisite environmental compliance laws and making a decision regarding how to proceed (including provisions for IPC and PAC funding upfront at a prorated amount based on cost allocation of Longhorn, BPA's NEPA, NHPA, and environmental compliance costs). Non-binding cost estimates identified for the potential Longhorn aspects of the B2H Project as of the Effective Date of this Term Sheet are as follows, which all Parties acknowledge and agree are preliminary and may be modified and revised prior to and upon B2H energization: *These are estimated costs, charges to be trued up with actual costs.* a. Longhorn (base substation) network costs ~$59M. Costs subject to transmission credit. i. IPC 21% ~ $12M (BPA to cover up to $14M of IPC cost) ii. PAC 55% ~ $33M iii. BPA 24% ~ $14M (plus IPC ~ $12M, for total ~ $26M) b. B2H connection to Longhorn Network Bay~$11M. Constructed/Owned/Maintained by BPA. Develop bay 3 with (2) 500kV circuit breakers & (5) 500kV disconnects. Costs subject to transmission credits. i. IPC & PAC 100% c. Customer built (not subject to transmission credits). Including civil work with the reactor and cap costs.

5.	***IPC & PAC*** ***New Agreement:*** ***Purchase and Sale Agreement for Asset Exchange -potentially utilize the previously developed Joint Purchase and Sale Agreement*** ***Prepare First Draft – IPC: Quarter 2 of Calendar Year 2022*** ***Target Execution Date: Quarter 4 of Calendar Year 2022***	PAC and IPC would purchase and sell to each other various assets to achieve the objectives identified in Section 3(a)(6) and Section 3(a)(7) of this table. PAC and IPC will seek to first balance the purchase and sale of the transferred assets through the depreciated net book value of such assets and allocation of upgrade costs and, finally, if necessary, will be balanced between IPC and PAC through cash considerations. <u>Details related to Populus – Four Corners assets</u>: These assets will provide IPC ownership on the existing PAC transmission system from Four Corners substation in New Mexico to Populus substation in Idaho. This will include 345 kV transmission lines between the following substations and assets to create a path through each substation: Four Corners, Pinto, Huntington, Camp Williams, Mona, Terminal, 90th South, Ben Lomond and Populus. Consistent with federal processes, IPC and PAC will complete required studies to determine if recent system upgrades result in a possible increase in existing transmission capacity between Borah and Populus to facilitate IPC's incremental transfer needs associated with this exchange. If determined necessary, IPC and PAC will identify revisions to the JOOA (as defined in Section 3(a)(6) of this table), upgrades, modifications, or other options to meet each party's commercial needs between Borah and Populus. <u>Details related to Borah/Kinport to Hemingway and Midpoint to Borah/Kinport assets</u>: These assets will provide PAC ownership on the existing IPC transmission system from Borah/Kinport to Hemingway and from Midpoint 500 to Borah/Kinport. This will include 500 kV and 345 kV transmission lines between the following substations and assets to create a path through each substation: Borah, Kinport, Adelaide, Midpoint and Hemingway. Upgrades are required across the Borah West and Midpoint West paths to facilitate this portion of the

		proposed asset exchange transaction. The cost of these upgrades will be determined in the course of negotiating the proposed asset exchange transaction described in this Section 3(a)(5). <u>Details related to Goshen Area assets</u>: As described in more detail in Section 3(a)(7) of this table, PAC will transfer to IPC certain to-be-determined Goshen areas transmission assets that would allow IPC to provide transmission service to all BPA customers in southeast Idaho currently served by PAC. These assets are being transferred to IPC, from PAC, as part of the negotiations between PAC and BPA as described in Section 3(a)(1) of this table, with the consideration for these assets being the transmission service provided by BPA to PAC as detailed in Section 3(a)(1) of this table. IPC and PAC intend for these Goshen assets to be incorporated into the broader purchase and sale agreement described in this Section 3(a)(5) with a goal of minimizing changes to each company's transmission rate base. This goal is intended to be facilitated through the allocation of the costs associated with the Borah West and Midpoint West upgrades.
6.	***IPC & PAC*** ***Amendment to Existing Agreement:*** ***IPC – PAC Joint Ownership and Operating Agreement ("JOOA")*** ***Prepare First Draft – IPC: Quarter 2 of Calendar Year 2022*** ***Target Execution Date: Quarter 4 of Calendar Year 2022***	As part of a transaction transferring assets described in Section 3(a)(5) of this table, IPC and PAC may expand their existing Joint Ownership and Operating Agreement, as amended and restated August 22, 2019 ("JOOA"), to include the following: I. PAC owning 300 MW of west-to-east transmission assets between Midpoint 500 and Borah (transferred from IPC); and II. PAC owning an additional 600 MW of east-to-west transmission assets between Borah and Hemingway (transferred from IPC) - total increases from the current 1,090 MW to 1,690 MW; and III. IPC owning 200 MW of bi-directional transmission assets between Populus, Mona and Four Corners (transferred from PAC); and IV. Other revisions as necessary to facilitate other asset exchanges (*e.g.*, for Goshen area, as

		described in Section 3(a)(5) and Section 3(a)(7) of this table).
7.	***IPC & PAC*** ***Goshen Area Asset Exchange*** ***Part of 3(a)(5)***	As referenced in Section 3(a)(5) and Section 3(a)(6) of this table, IPC and PAC would negotiate an asset exchange to be effective no later than (i) energization of the B2H line and (ii) commencement of the NITSA between BPA and IPC, as referenced in Section 3(b)(1), that enables BPA to to serve its loads currently in PAC's East transmission system (Lower Valley Elec., Idaho Falls, Fall River Rural Elec., Lost River Electric, Salmon River Electric, Soda Springs,) ("Southeast Idaho Load Service (SILS) Customers") with one leg of firm IPC network transmission service. As referenced in Section 3(a)(6) of this table, the Goshen area asset exchange may be wrapped into the existing JOOA framework. IPC, PAC, and BPA agree to make best efforts to plan for service to Idaho Falls that requires only one leg of network transmission from the BPA transmission system, provided such best efforts among the Parties must (1) respect and retain the existing services arranged for Idaho Falls load service between BPA and Utah Associated Municipal Power Systems (UAMPS); and (2) be in line with FERC orders in similar circumstances and accepted by FERC.
8.	***IPC & BPA*** ***New Agreement:*** ***Point to Point TSA*** ***Prepare First Draft – BPA: Quarter 2 of Calendar Year 2022*** ***Target Execution Date: Quarter 3 of Calendar Year 2022***	IPC will acquire up to 500 MW of PTP transmission service from Mid-C to Longhorn subject to the terms of BPA's OATT, business practices and applicable rate schedules. The duration of the new service must be for an initial service duration of at least 5 years, and sufficient to compensate BPA for BPA's revenue requirement associated with BPA capital investments to facilitate the transmission service, with the right to rollover service in accordance with the BPA's OATT and business practices in effect at the conclusion of the initial term.

9.	***IPC & PAC***	Upon energization of the B2H Project, PAC would not renew its current 510 MW of east-to-west rights on the IPC system (which rights are found in IPC 1st Revised Service Agreement (SA) Nos. SAs 344-346 and 383-384). Consistent with and pursuant to IPC's OATT, PAC and IPC will coordinate to extend any remaining IPC SAs, enter into new SAs, or take other action as necessary to bridge any SA expiration dates until such time as the B2H project is in-service.
10.	***IPC & PAC*** ***B2H Construction Funding Agreement-related Commitments***	The B2H Construction Funding Agreement, between IPC and PAC as referenced in Section 3(d) below, and any additional agreements as the Parties determine necessary, will include terms necessary to implement the Agreement to Reimburse BPA's Removal and Replacement Related Transaction Costs, among IPC, PAC and BPA, dated March 18, 2020 (BPA Contract No. 20TX-16835). IPC, on behalf of the B2H Project, will assure that it coordinates construction of the B2H Project with BPA in a manner consistent with the terms of BPA's Use Agreement, as amended by Amendment Two (2) to NF(R)-9617, including Exhibits A, B and C, between the United States of America, Dept. of the Navy and the United States of America, Bonneville Power Administration Ptn Secs 13, 23 and 24-T2N-R25E, W.M. IPC and PAC acknowledge that the Removal and Replacement Related Transactions described in Contract No. 20TX-16835 are contingent upon (1) BPA obtaining acceptable service from Umatilla Electric so that BPA may continue to serve Columbia Basin Electric's load; (2) BPA completing its obligations and responsibilities under NEPA, NHPA, or other requisite environmental compliance laws and making a decision regarding how to proceed; and (3) IPC and PAC moving forward with construction of the B2H Project.
11.	***IPC & PAC & BPA***	In conjunction with the termination of the NITSAs identified in Section 3(a)(3) of this table (*i.e.*, PAC

	BPA Redirect and Assignment of existing PTP transmission service ***Incorporate into Agreement on Principles and Timelines under 3(a)(1)***	SAs 746 & 747), following the energization of B2H, BPA will redirect its two 100 MW PTP transmission service agreements (91629850 and 91629500, or any applicable AREFs that supersede or replace them) that it takes from IPC (*i.e.*, IPC 1st Revised SAs 324 & 342) such that the new POR of each SA will be Walla Walla and the new POD for each SA will be Borah. Consistent with and pursuant to IPC OATT, following approval of such redirects by IPC as described above, BPA will assign those redirected reservations to PAC. This redirect and assignment will be delayed by BPA if B2H energization is delayed past 07/01/2026. PAC shall be responsible to pay for all costs associated with 91629850 and 91629500, or any applicable AREFs that supersede or replace them, upon approval of such redirect by IPC and assignment by BPA.
12.	***IPC & PAC & BPA, with respect to B2H Plus Facilities Expectations*** ***IPC & PAC, with respect to B2H Construction Funding Agreement***	The B2H Project will include the installation of the B2H Midline Series Capacitor Project and development of a remedial action scheme ("RAS"). When considering BPA's study methodology, the B2H midline series capacitor reduces simultaneous interactions between the NW AC Intertie, central and southern Oregon load service, and WECC Path 14 (Idaho to Northwest). The Parties agree to funding of the B2H Midline Series Capacitor Project as follows: a. IPC: funding 45% of the cost. b. PAC: funding 55% of the cost c. BPA: funding 0% of the cost The Parties will work in good faith to have the B2H Midline Series Capacitor Project in-service when the B2H Project is energized and to document expectations of operation, maintenance, and future reinforcements and upgrades.
13.	***IPC & PAC*** ***B2H Grant or Additional Funding***	Under IPC and PAC's existing OATT rate procedures, IPC and PAC will include any United States Department of Energy ("DOE") grant or additional funding received for the B2H project in the appropriate FERC account provided such account is allocated 100% to Transmission. Nothing in this Term Sheet limits or waives any party's right to participate, review, comment, or challenge the other

		party's rate case or formula rate inputs through their respective update processes.
14.	***IPC & PAC & BPA*** ***Permit Funding Agreement Amendment***	Upon transfer of BPA's Permitting Interest to IPC identified in 3(b)(3) below, the Permit Funding Agreement will be amended to recognize the re-allocation of the Parties' Permiting Interests and related funding obligations.

b) NITSA Terms and Conditions, NITSA Security Agreement, NITSA Backstop

1.	***IPC & BPA*** ***New Agreements:*** ***Network Integration Transmission Service Agreement to serve BPA customers at Goshen*** ***Network Integration Transmission Service Agreement to service BPA's customer at Burley*** ***Amendment to currently effective Network Integration Transmission Service Agreements*** ***Prepare First Draft – IPC: Quarter 2 of Calendar Year 2022***	IPC and BPA will enter into two NITSAs for IPC to provide firm network transmission service to BPA. One NITSA will serve BPA customers at Goshen (replacing what is, as of the Effective Date of this Term Sheet, provided under PAC Service Agreement 746) and one NITSA will serve Idaho Falls (replacing what is, as of the Effective Date of this Term Sheet, provided under PAC Service Agreement 747) ("New NITSAs"). The New NITSAs will be in addition to the existing NITSAs BPA currently holds with IPC for service to BPA's customers located on IPC's system ("Existing NITSAs"). The term of BPA's New NITSAs will be 20-years from energization of the B2H Project, with a renewal or rollover option at BPA's discretion as required and permitted by FERC a. The NITSA Security Agreement (as referenced in Section 3(b)(2) of this table), and any related other agreements necessary, between BPA and IPC will be updated once the energization of B2H has occurred to document the term and the repayment periods with the actual energization date. b. The New NITSAs, NITSA Security Agreement, and any related other agreements necessary, are conditioned on the Goshen Area Asset Exchange set forth in Section 3(a)(7) being completed and all associated agreements being in effect by the energization of the B2H line.

	Target Execution Date: Quarter 3 of Calendar Year 2022	The New NITSAs and the Existing NITSAs will be updated to include three Points of Receipt (PORs) over which BPA can deliver energy to its customers located on IPC's system. The three PORs are as follows: AMPS POR, LaGrande POR, and Longhorn POR. The New NITSAs shall reflect the following provisions: a. Under the New NITSAs, IPC will plan for and reserve transmission capacity for the continued network service to BPA's SILS Customers' loads and ensure that it can reliably serve the load for the term of the contract prior to BPA assigning the PTP service agreements to PAC pursuant to Section 3(a)(11) above. b. The New NITSAs between BPA and IPC will permit BPA to assign service to specific Points of Delivery (PODs) to BPA's wholesale customers who take service at those PODs. Such assigned PODs will be served by a separate NITSA agreement between BPA's wholesale customer and IPC. The New NITSA between BPA and IPC will state that the customer requesting a separate NITSA for its POD must meet credit rating standards consistent with IPC's OATT. Notwithstanding assignment of the NITS service, BPA would remain entitled to all outstanding credits associated with the Funded Amounts (as defined in Section 3(b)(2) below) as long as BPA continues to be a NITS customer. c. IPC will maintain the current practice of letting BPA choose through the annual delivery allocation process the PODs where BPA will deliver power to serve its loads. The current PODs include LaGrande and AMPS. Once B2H is in service, the PODs will include LaGrande, Longhorn, and AMPS. d. BPA would pay the NT rate as established by IPC's OATT transmission formula rate. There shall be no adders or segmentation

		like actions which result in a rate above the NT rate and the amount BPA pays to IPC under the NT service agreement will be reduced as discussed in the NITSA Security Agreement. e. IPC will not charge BPA IPC's system losses for energy from BPA's Palisades resource used to serve load behind Goshen.
2.	***IPC & BPA*** ***New Agreement:*** ***NITSA Security and Risk Backstop Agreement*** ***Prepare First Draft – IPC: Quarter 2 of Calendar Year 2022*** ***Target Execution Date: Quarter 3 of Calendar Year 2022***	IPC and BPA will enter into an NITSA security and risk backstop agreement ("NITSA Security Agreement"), concurrently with the New NITSA and the purchase and sale agreement referenced in Section 3(b)(3) of this table. <u>Reimbursement If IPC Receives all Permits and Certificates of Public Convenience and Necessity (CPCN) for Construction of B2H</u> IPC will reimburse BPA for the transfer of BPA's Permitting Interest under the Joint Permitting Agreement in an amount consisting of BPA's investment in B2H prior to the transfer date (~$25m). BPA will also pay to IPC an additional $10 million upon execution of the New NITSAs and the NITSA Security Agreement with the intent of offsetting overall B2H project costs in IPC's rate base. The additional $10 million plus BPA's investment in B2H will be collectively referred to as the "Funded Amount." IPC will retain the Funded Amount as follows: If and when IPC obtains all necessary CPCNs and permits for the B2H Project (and all appeals, if any, have been resolved), IPC shall have until January 1, 2026 ("Commencement Date") to commence construction of B2H or to inform BPA of its intent to not pursue construction of B2H. (1) If IPC commences construction of B2H by or before the Commencement Date, then: a. Interest on the Funded Amount (~$35m) payable by IPC to BPA will accrue from the date of energization of B2H at the rate

		established in the applicable IPC tariff for customer funded projects; b. The Funded Amount and all accrued interest will be repaid to BPA starting year 11 following the energization date (the “Refund Commencement Date”), with repayment amortized over the remaining 10 years of the New NITSAs. i. IPC and BPA will incorporate the interest schedule and payment amortization as an exhibit to the NITSA Security Agreement; ii. If during the term of the New NITSAs BPA defaults on its payment obligations under the New NITSAs, IPC will be entitled to retain for its own account an amount equal to the defaulted payment obligation not to exceed the amount not reimbursed to BPA as of the default date; iii. BPA will not be considered in default for any amount not paid subject to a billing dispute; and iv. IPC may prepay the Funded Amount and interest thereon at any time without penalty. (2) If IPC does not commence construction of B2H by or before the Commencement Date or if IPC informs BPA before the Commencement Date of its intent to not proceed with B2H, then: a. IPC shall have 180 days from the Commencement Date (or notice to BPA of its intent to not proceed, whichever is earlier) to sell its Permitting Interests in the B2H Project; b. No later than the close of the above mentioned 180 days, IPC shall i. pay to BPA BPA’s proportional share of any proceeds received from the sale of its Permitting Interest in the B2H Project (if any), and

		ii. Pay to BPA the $10 million BPA provided to IPC upon execution of the New NITSAs. Risk Backstop if IPC does not Receive all Permits or CPCNs Necessary for constructing B2H. If IPC does not obtain all necessary CPCNs and permits for the B2H Project, or any such CPCNs or permits are overturned on appeal, then (a) IPC will return to BPA the $10 million BPA provided to IPC upon execution of the New NITSAs; and (b) BPA will reimburse IPC for funding the additional 24.24% share of all B2H Permitting and Preconstruction Costs incurred after BPA transfers its 24.24% Permitting Interest to IPC. The reimbursement obligation will not include any costs related to Right of Way option acquisition or exercising Right of Way Options. The risk backstop commitment will remain in place until IPC obtains all necessary CPCNs and permits for the Project (and all appeals, if any, have been resolved). The intent of the backstop is only to assist IPC in mitigating the risk associated with receiving the approvals for the B2H Project; not to assist in mitigating business risk. The risk backstop commitment will be as follows: a. IPC will not compensate or reimburse BPA for costs expended by BPA on B2H prior to the transfer of the Permitting Interest to IPC (*i.e.*, ~$25m BPA has expended to date); b. BPA will reimburse 24.24% of actual B2H Project Permitting Costs incurred after IPC takes over funding 45% of the project. (Current estimates for 2021-2024 – Total B2H Project estimated at $9,125,466 with 24.24% of these costs estimated at $2,212,234); and c. BPA will reimburse 24.24% of actual B2H Project Pre-Construction Costs incurred after IPC assumes funding 45% of the project. (Current estimates for

		2021-2024 – Total B2H Project estimated at $9,403,564 with 24.24% of these costs estimated at $2,279,652). Collectively, these amounts set forth in a. through c. above will be the "Risk Backstop Amount." The Risk Backstop Amount will be adjusted, as necessary, to the extent that IPC receives grants or forms of other financial assistance from sources other than BPA or PAC. For example, if IPC received a government grant that defrayed the pre-construction costs of B2H, BPA's 24.24 % share of the pre-construction costs would be reduced accordingly.
3.	***Transfer of Interest in Joint Permitting Agreement:*** ***Prepare First Draft – IPC: Quarter 2 of Calendar Year 2022*** ***Target Execution Date: Quarter 3 of Calendar Year 2022***	IPC and BPA will execute a purchase and sale agreement, assignment, and other applicable transfer documents, concurrently with the New NITSAs, NITSA Security Agreement, and any related other agreements necessary, to transfer all of BPA's Permitting Interest under the Joint Permitting Agreement (and all of BPA's interest in the assets associated therewith) to IPC in exchange for IPC's agreement for repayment to BPA of BPA's investment in B2H through the Joint Permitting Agreement through the effective date of the definitive purchase and sale agreement contemplated in this Section 3(b) (or other date specified therein). The proposed purchase and sale agreement contemplated in this Section 3(b)(3) will contain representations, warranties, and covenants typical of a transaction of the nature contemplated by these proposed terms. The definitive agreements transferring BPA's Permitting Interest under the Joint Permitting Agreement and related assets will be executed prior to any activities BPA has indicated could impact federal environmental regulatory requirements under NEPA, so as to prevent additional delay in the development of B2H. Following the transfer of BPA's Permitting Interest (and associated assets) under the Joint Permitting Agreement to IPC, IPC will be solely responsible for funding an additional 24.24% share of all B2H Project Costs thereafter under Joint Permitting Agreement

		(which includes permitting and preconstruction costs), and IPC will be entitled to all rights, title, and interests and assets that BPA would otherwise obtain under the Joint Permitting Agreement if it were a remaining funding party thereto.

c) Ownership, Operation, and Maintenance Agreement: Defines IPC's and PAC's capacity and property ownership, and their roles and responsibilities for operating and maintaining the B2H Project ("***Ownership and Operation Agreement***"). IPC will prepare an initial draft of the Ownership and Operation Agreement based on the ownership interests below and otherwise consistent with the terms of the JOOA between IPC and PAC. Alternatively, in lieu of a new agreement, IPC and PAC may decide to amend the existing JOOA to cover the B2H Project assets.

Idaho Power	**PacifiCorp**	**BPA**
Project ownership: 45.45%	Project ownership: 54.55%	Project ownership: 0%

d) Construction Funding Agreement: Defines IPC's and PAC's roles and responsibilities in construction of the B2H Project ("***Construction Funding Agreement***"). IPC will prepare an initial draft of the Construction Funding Agreement consistent with the following terms:

1. Project In-Service Date	June 1, 2026
2. Scope	The Construction Funding Agreement covers all work necessary to construct the B2H Project by the Project In-Service Date, including any associated residual work after the Project In-Service Date, but excluding any work already covered by the Joint Permitting Agreement.
3. Project Delivery System	A competitive process is being completed to hire a Construction Manager / Constructability Consultant ("CM") for the B2H Project in 2022 to: (1) provide constructability feedback to the design engineer; and (2) collaborate with PAC and IPC to complete the BLM Construction Plan of Development and the Oregon Energy Facility Siting Council's Site Certificate amendments. The hiring process of the CM will be structured such that the CM may be retained to construct the B2H Project.

	IPC and PAC may mutually agree to modify the CM's role through the Construction Funding Committee (as defined in Section 10 below -***Project Funding and Committee***) without amending the Construction Funding Agreement.
4. Project Manager	IPC is the overall Project Manager for all B2H Project permitting, design, procurement, construction, except that BPA will be responsible for designing, procuring, and constructing the Longhorn substation as described in Section 3(a)(4) and relocating and replacing the BPA 69 kV line off Navy property as described in Section 3(a)(10). Although IPC is the Project Manager, PAC is not precluded from taking project management responsibilities for all or selected tasks associated with the B2H Project; provided that these delegations must be made by the Construction Funding Committee.
5. Construction Project Manager	IPC's role as Construction Project Manager will be generally consistent with the roles and responsibilities of the Permitting Project Manager set forth in Article IV of the Joint Permitting Agreement, provided that the permitting responsibilities not relevant to construction will be removed. IPC, as the Construction Project Manager, will provide monthly project updates, including updates on project activities, financials, forecasts, and invoices detailing costs incurred with breakdowns demonstrating all Parties' cost responsibilities based on their percentage shares. To provide the necessary flexibility to avoid delay/additional costs, the Construction Project Manager will administer and oversee all work necessary to construct the B2H Project within the approved budget, schedule and scope, and also have authority to approve any non-material changes to the B2H Project resulting in a price difference of less than $500k, so long as the overall B2H Project costs remain within the approved budget with the price change. All changes to the B2H Project resulting in a change in the approved budget, will require approval of the Construction Funding Committee.

6. Component Specifications	All B2H Project construction specifications shall meet or exceed all applicable state and federal design requirements and standards; provided that, such specifications may be modified by the Construction Funding Committee so long as the project complies with all applicable state and federal design requirements and standards.
7. Real Property Ownership	<u>B2H real property, except Longhorn substation</u>: IPC will acquire rights of way, grants, easements, or other interests in real property necessary to construct, operate and maintain the B2H transmission line and grant to PAC perpetual and sufficient rights of access, to be set forth in the Ownership and Operation Agreement. <u>Longhorn Substation</u>: Upon completion of BPA's obligations and responsibilities under NEPA, NHPA, and other requisite environmental compliance laws and if BPA decides to proceed with construction of Longhorn substation, BPA will continue to own all real property associated with the Longhorn substation, and in relation to the B2H Project equipment BPA shall grant to IPC and PAC perpetual and sufficient rights of access, to be set forth in one or more Longhorn Substation Agreements as described in Section 3(a)(4).
8. Equipment and Facilities Ownership	Equipment and facilities ownership will be consistent with the Ownership and Operation Agreement. <u>B2H equipment/facilities, except Longhorn substation</u>: IPC and PAC will jointly own as tenants in common the transmission line and all associated facilities and equipment, including all associated facilities located in Hemingway Substation as well as supporting communication facilities and B2H Project substation equipment. <u>Longhorn Substation</u>: Upon completion of BPA's obligations and responsibilities under NEPA, NHPA, and other requisite environmental compliance laws and if BPA decides to proceed with construction of Longhorn substation, BPA will own all equipment and facilities in the Longhorn substation, except the B2H specific equipment and facilities which will be jointly owned by IPC and PAC as tenants in common. BPA will grant IPC and PAC access rights to the equipment

	and facilities in Longhorn substation that are constructed as part of and necessary to the operation of the B2H transmission line facilities, to be set forth in one or more Longhorn Substation Agreements as described in Section 3(a)(4).
9. Material Procurement	All material specifications shall be in accordance with IPC's procurement policies and standards, unless otherwise agreed by the Construction Funding Committee to exceed the same.
10. Project Funding and Committee	Funding: IPC and PAC will fund the B2H Project consistent with their respective ownership shares. Construction Funding Committee: The Construction Funding Agreement shall create a Construction Funding Committee consistent with IPC and PAC's ownership interests in the B2H Project, and generally consistent with the Permit Funding Committee created by the Joint Permitting Agreement (Article III). The Project Manager's reporting requirements set forth in the above Section 5 (***Construction Project Manager)*** will be delivered to all members of the Construction Funding Committee prior to, and discussed during, each of the Committee's regularly-scheduled monthly meetings. Obligations, disputed amounts, and audit rights will be generally consistent with Article III of the Joint Permitting Agreement. The Project Manager will have flexibility to make day-to-day decisions associated with construction of the Project but will be required to seek resolution/approval from the Construction Funding Committee on larger dollar/impact decisions, consistent with that set forth in the above Section 5 (***Construction Project Manager***). BPA will be responsible for designing, procuring, and constructing the Longhorn substation as described in Section 3(a)(4) and relocating and replacing the BPA 69 kV line off Navy property, as described in Section 3(a)(10).
11. Payment Schedule	Costs Accrued Prior to Agreement Execution: Prior to executing the Construction Funding Agreement, IPC

	and PAC will have the opportunity to audit all accrued construction-related expenses included therein that have not otherwise been funded under the Joint Permitting Agreement. IPC and PAC will align on ownership shares prior to execution of the Construction Funding Agreement and pay their respective portions of accrued expenses within 30 days of the effective date of the Construction Funding Agreement. Until which time BPA fully divests its ownership interest in the B2H Project, the Parties acknowledge that the B2H Project is bound to compliance with NEPA, NHPA, and other environmental laws associated with federal agency action. <u>Costs Incurred After Execution</u>: Following execution of the Construction Funding Agreement, the Project Manager will invoice the Construction Funding Agreement participants monthly, requiring payment within 30 days of the invoice date.
12. Transfer/Assignment of Rights/Interests *(Some or all of these terms may be instead placed in the Ownership Agreement)*	IPC and PAC may sell some or all of their respective ownership interests in the B2H Project, together with associated capacity, subject to the Construction Funding Committee's agreement and approval of the terms of any such transaction; provided that, such approval will not be unreasonably withheld. IPC will not transfer or assign rights or interests in the B2H Project that would materially impact the BPA load service commitments set forth in Section 3(b) of this Term Sheet.
13. Term ***Early Termination*** ***Withdrawal***	<u>Term</u>: The term of the Construction Funding Agreement will extend through completion of B2H Project construction, as well as final billing and any reconciliation or mitigation associated with the final expenses, unless otherwise agreed by the Construction Funding Committee. <u>Early Termination/Withdrawal</u>: Absent approval of the Construction Funding Committee, no Party shall have a right to withdraw from the Construction Funding Agreement following the earlier of (1) awarding the B2H Project construction contract, or (2) commencing procurement of long-lead items and equipment.

	Assignments of IPC's or PAC's rights and obligations under the Construction Funding Agreement shall be managed pursuant to the above Section 12 (***Transfer/Assignment of Rights/Interests***).
14. Event of Default	Generally consistent with Article VIII of the Joint Permitting Agreement.
15. Force Majeure	Generally consistent with Article IX of the Joint Permitting Agreement.
16. Reps and Warranties	Generally consistent with Article X of the Joint Permitting Agreement.
17. Common Defense & Limitation of Liability	Generally consistent with Article XI of the Joint Permitting Agreement, except that the Article will be expanded to address construction claims.
18. Proprietary Information/Confidentiality	Generally consistent with Article XII of the Joint Permitting Agreement, except that the Article will provide IPC the ability to share information as necessary to work with potential and selected engineers and contractors.
19. Dispute Resolution	Generally consistent with Article XIII of the Joint Permitting Agreement.
20. Miscellaneous	Generally consistent with Article XIV of the Joint Permitting Agreement and including any standard terms that are necessary for PAC agreements (e.g. assignment and jury trial waiver provisions).

4. Additional Agreements. The Parties agree that they may consolidate any or all of the above-described Agreements and are not precluded from pursuing additional agreements, or amending existing agreements as needed, related to the B2H Project besides those discussed herein.

5. Expenses. Each Party will bear its own expenses (including attorneys' fees) incurred in connection with preparation, negotiation, and execution of this Term Sheet, including preparation, negotiation and execution of the Agreements described herein.

ACKNOWLEDGED AND AGREED TO BY THE PARTIES:

IDAHO POWER COMPANY

Signature: Ryan N. Adelman

Printed Name: RYAN N ADELMAN

Title: VP, POWER SUPPLY

Date: 1/18/22

PACIFICORP

Signature: Rick Link Digitally signed by Rick Link Date: 2022.01.18 11:11:21 -08'00'

Printed Name: Rick Link

Title: Senior Vice President, Resource Planning, Procurement and Optimization

Date: 01/18/2022

Signature: Rick Vail Digitally signed by Rick Vail Date: 2022.01.18 11:59:50 -08'00'

Printed Name: Rick Vail

Title: Vice President, Transmission

Date: 01/18/2022

BONNEVILLE POWER ADMINISTRATION

Signature: TINA KO Digitally signed by TINA KO Date: 2022.01.18 04:25:04 -08'00'

Printed Name: Tina Ko

Title: Vice President, Transmission Marketing a

Date: 1/18/2022

Signature: Digitally signed by KIM THOMPSON Date: 2022.01.18 07:32:28 -08'00'

Printed Name: Kim Thompson

Title: Vice President, Requirements Marl

Date: 1/18/2022

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-01

IDAHO POWER COMPANY

CONFIDENTIAL

ELLSWORTH
TESTIMONY

EXHIBIT NO. 2

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-01

IDAHO POWER COMPANY

ELLSWORTH
TESTIMONY

EXHIBIT NO. 3

From: Tech Forum <techforum@bpa.gov>
Sent: Thursday, January 5, 2023 3:39 PM
To: Tech Forum
Subject: [EXTERNAL]BPA Southeast Idaho Loads and B2H Transfer Service Workshop

Bonneville Power Administration

Requested Action: Information Only

Subject Description:

In a Letter to the Region dated January 18, 2022 ("2022 Letter"), BPA announced its signature of a non-binding term sheet ("Term Sheet") that clarified and updated BPA's role in Idaho Power and PacifiCorp's potential future construction of their new transmission line from Boardman, Oregon to Hemingway, Idaho (the "Boardman to Hemingway Project" or "B2H").

The term sheet developed a plan referred to as "B2H with Transfer Service", and would allow BPA to reliably and cost-effectively meet firm power service obligations to southeast Idaho customers by acquiring transmission service on B2H rather than becoming a part owner in the line as previously considered. The 2022 Letter and the Term Sheet are available on BPA's Southeast Idaho Load Service (SILS) webpage.

It was also noted that Idaho Power, PacifiCorp, and BPA intended to negotiate binding contracts to effectuate the B2H with Transfer Service plan of service. As those negotiations near conclusion, BPA is providing customers and stakeholders with advance notice of the following public engagement schedule which will include a formal comment period for stakeholders:

- Monday, Jan. 9: BPA will release a Letter to the Region, describing the contracts associated with B2H with Transfer Service that BPA is proposing to execute.
- Monday, Jan. 9: BPA will make an online comment page available at https://publiccomments.bpa.gov for B2H with Transfer Service comments.
- Monday, Jan. 23: from 1-3 p.m., BPA will hold a public workshop to discuss the binding contracts and BPA's business case, as well as provide Q&A opportunities.
- Thursday, Feb. 9: BPA will close the public comment period and begin preparing responses.

BPA will present information at the Jan. 23 workshop (details below) intended to help interested parties prepare public comments on the proposal to execute the binding contracts. Materials for the Jan. 23 meeting will be available on BPA's SILS webpage prior to the workshop.

BPA will be accepting public comments at https://publiccomments.bpa.gov until Thursday, Feb. 9, 2023.

Meeting Details:

When: Jan. 23, 2023

Time: 1 p.m. to 3 p.m.

Where: Webex join the meeting

Phone Bridge: 415-527-5035

Meeting Number (access code): 2763 013 9005

For the most up-to-date calendar of events, please visit the BPA Event Calendar.

To submit comments and questions or unsubscribe, email to techforum@bpa.gov. Click here to subscribe.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

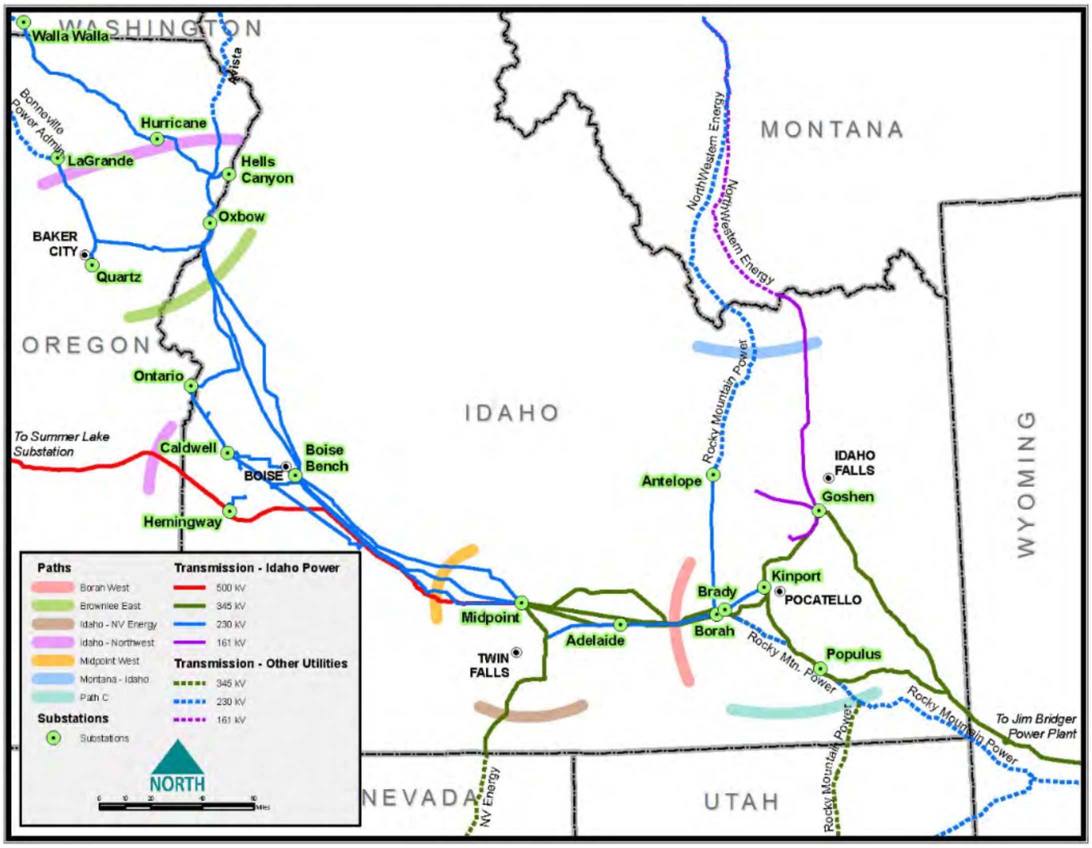
CASE NO. IPC-E-23-01

IDAHO POWER COMPANY

ELLSWORTH
TESTIMONY

EXHIBIT NO. 4

Idaho Power's Existing Voltage Transmission System



BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

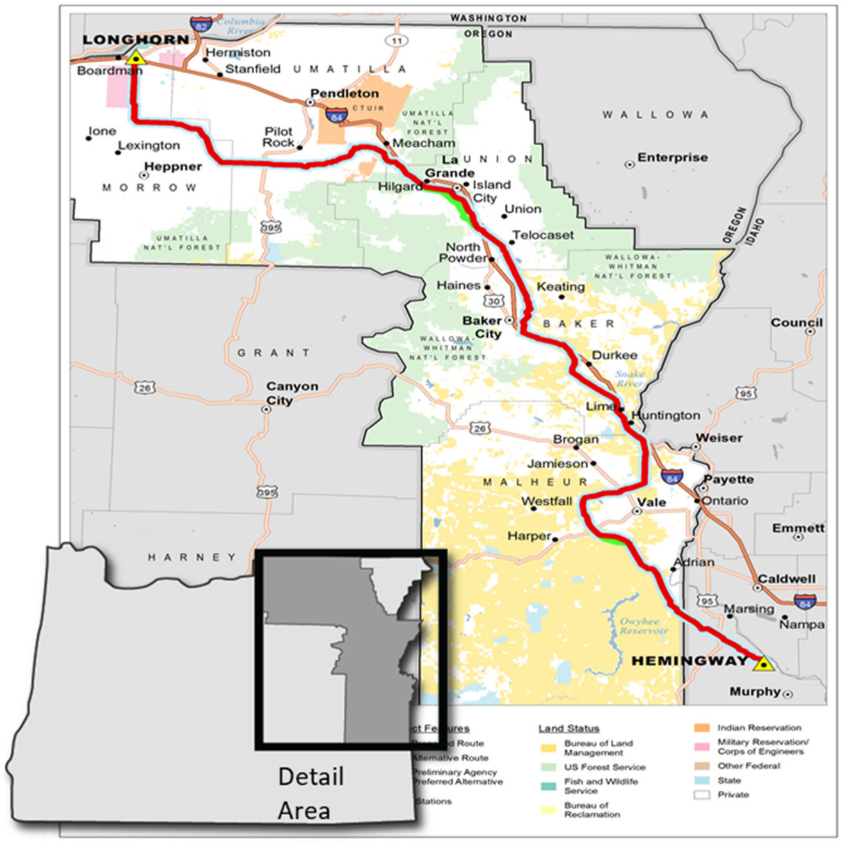
CASE NO. IPC-E-23-01

IDAHO POWER COMPANY

ELLSWORTH
TESTIMONY

EXHIBIT No. 5

Boardman to Hemingway Project



BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-01

IDAHO POWER COMPANY

ELLSWORTH
TESTIMONY

EXHIBIT NO. 6

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-01

IDAHO POWER COMPANY

ELLSWORTH
TESTIMONY

EXHIBIT NO. 7

2021 IRP: Branching Evaluation