BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR A CERTIFICATE OF CONVENIENCE AND NECESSITY AUTHORIZING CONSTRUCTION OF THE BOARDMAN-TO-HEMINGWAY 500-KV TRANSMISSION LINE PROJECT	)))))))	**CASE NO. PAC-E-23-01** **DIRECT TESTIMONY OF RICK T. LINK**

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-23-01

January 2023

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ATTACHED EXHIBITS

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Rocky Mountain Power ("PacifiCorp" or the "Company").

A. My name is Rick T. Link. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My position is Senior Vice President, Resource Planning, Procurement and Optimization.

Q. Please describe the responsibilities of your current position.

A. I am responsible for PacifiCorp's energy supply management and resource planning and procurement functions, which includes the integrated resource plan ("IRP"), structured commercial business and valuation activities, and long-term load forecasts. Most relevant to this docket, in coordination with Company witness Mr. Rick Vail, I am responsible for contract negotiations required for PacifiCorp's participation in the Boardman-to-Hemingway project ("B2H" or the "Project"). I am also responsible for the economic analysis of B2H.

Q. Please describe your professional experience and education.

A. I joined PacifiCorp in December 2003 and assumed the responsibilities of my current position in September 2021. Over this period, I held several analytical and leadership positions responsible for developing long-term commodity price forecasts, pricing structured commercial contract opportunities, developing financial models to evaluate resource and transmission investment opportunities, negotiating commercial contract terms, and overseeing development of PacifiCorp's resource plans. I was responsible for delivering PacifiCorp's 2013, 2015, 2017, 2019, and 2021 IRPs; have been directly involved in implementing and overseeing resource RFP processes; and performed economic analysis supporting a range of resource and transmission investment opportunities. Before joining PacifiCorp, I was an energy and environmental economics consultant with ICF Consulting (now ICF International) from 1999 to 2003, where I performed electric sector financial modeling of environmental policies and resource investment opportunities for utility clients. I received a Bachelor of Science degree in Environmental Science from the Ohio State University in 1996 and a Master of Environmental Management degree from Duke University in 1999.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have testified in proceedings before the Idaho Public Utilities Commission ("Commission"), the Utah Public Service Commission, the Wyoming Public Service Commission, the Public Utility Commission of Oregon, the Washington Utilities and Transportation Commission, and the California Public Utilities Commission.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your direct testimony?

A. I present and explain the economic analysis that supports PacifiCorp's request for a certificate of public convenience and necessity ("CPCN") for B2H. I explain how B2H and related changes to PacifiCorp's transmission system and operations were analyzed and shown to be cost effective in PacifiCorp's 2021 IRP and 2021 IRP Update, and provide current economic analysis demonstrating customer benefits associated with the Project.

Q. Please summarize your direct testimony regarding B2H.

A. The 2021 IRP and 2021 IRP Update showed that B2H is necessary to meet the Company's need to reliably and cost effectively serve customers, and it was part of the preferred portfolio in both plans. Both the 2021 IRP and 2021 IRP Update specifically examined the portfolio impacts and system cost implications of not participating in B2H relative to the preferred portfolio outcome that included it. Both analyses showed that building B2H was the least-cost, least-risk outcome. In the 2021 IRP, B2H was projected to result in $453 million in risk-adjusted net benefits during the study horizon of 2021 through 2040.[1] Similarly, the 2021 IRP Update projected risk-adjusted net benefits of $439 million during the same period.[2]

Since the 2021 IRP Update was prepared, several key changes have occurred. First, the Company's most recent load forecast has significantly increased, reflecting both new load and the impact of climate change. Second, the United States Environmental Protection Agency ("EPA") proposed its "Ozone Transport Rule" (also called the "Good Neighbor Rule" or "Cross-State Air Pollution Rule") to establish allowance-based emissions limits for nitrogen oxides ("NOx") that will impact PacifiCorp's thermal resources in Utah and Wyoming. Third, the enactment of the federal Inflation Reduction Act ("IRA") has extended and expanded tax incentives for clean generation and energy storage resources. Finally, PacifiCorp's transmission service requirements have evolved considering that the Bonneville Power Administration ("BPA") may be unable to reasonably accommodate some of the modifications to PacifiCorp's existing transmission service arrangements contemplated in the non-binding B2H Term Sheet,

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[1] PacifiCorp's 2021 Integrated Resource Plan. Volume I. September 1, 2021. Pg. 271-272. Available at: https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021-irp/Volume%20I%20-%209.15.2021%20Final.pdf

[2] PacifiCorp's 2021 Integrated Resource Plan Update. March 31, 2022. Pg. 89-91. Available at: https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021_IRP_Update.pdf

dated January 18, 2022, attached as Exhibit No. 1.[3] After incorporating these and other associated changes, B2H is now projected to result in \$1.713 billion in risk-adjusted net benefits during a study horizon of 2023 through 2042, assuming medium natural gas and carbon prices.

The Project significantly enhances the capability of the regional electric grid, and the current B2H benefit estimate has three distinct aspects. First, B2H will increase the bidirectional transfer capability between PacifiCorp's east and west balancing authority areas ("BAA"). Second, B2H enables lower-cost and more reliable transmission service to PacifiCorp's central Oregon loads. Third, B2H allows for lower cost transmission service to PacifiCorp loads in the vicinity of BPA's planned Longhorn substation, which is the western terminus of B2H.[4]

In the Company's economic analysis, PacifiCorp evaluated the change in revenue requirement associated with B2H using the PLEXOS model under a range of natural gas price and CO_2 policy assumptions ("price-policy scenarios"). PacifiCorp calculated the change in system revenue requirement between cases with and without B2H, where capital revenue requirement is levelized.

The change in annual nominal revenue requirement through 2042 was also calculated to provide some perspective around potential rate pressures relative to a case that does not include B2H.

[3] The Term Sheet is also available at: https://docs.idahopower.com/pdfs/B2H/B2H-termsheet-bpapacIPCSigned-IP.pdf
[4] The Longhorn substation is approximately four miles east of the city of Boardman, Oregon.

PacifiCorp requests that the Commission grant a CPCN for B2H no later than the end of June 2023 to ensure timely energization for this critical transmission system upgrade.

III. OVERVIEW OF B2H

Q. Please describe B2H.

A. B2H is a high voltage single-circuit 500-kV alternating current transmission line that extends approximately 300 miles from north-central Oregon to southwest Idaho. In the context of PacifiCorp's long-term transmission plan, B2H is also referred to as Segment H of Energy Gateway.

Q. Is the Company the only party involved in B2H?

A. No. Idaho Power Company ("IPC") is the overall project manager, responsible for all B2H permitting, design, procurement, and construction. IPC will fund and own 45.45 percent of B2H and the Company will fund and own 54.55 percent of B2H. BPA has also partnered with IPC and the Company in the development of B2H. However, BPA will not have an ownership interest in B2H and instead intends to acquire B2H capacity from IPC through transmission service agreements.

Q. Has IPC filed a CPCN application in Idaho for B2H?

A. Yes. IPC filed a CPCN application for B2H on January 9, 2023, in Case No. IPC-E-23-01.

IV. 2021 INTEGRATED RESOURCE PLAN

Q. Does the 2021 IRP identify a need for additional resources and transmission to serve PacifiCorp's customers?

A. Yes. The primary focus of any IRP is to forecast customer demand and to evaluate different combinations of resources and transmission to meet that customer demand over time. In the 2021 IRP, the preferred portfolio represents the least-cost, least-risk portfolio of resources and transmission options, as presented in Tables 9.16 and 9.17 in Chapter 9 of Volume I. Consistent with prior IRPs, in the 2021 IRP, all resource portfolios that were considered as candidates for the preferred portfolio contain new supply-side, demand-side, market resources, and transmission upgrades necessary to meet customer demand.

Q. Was B2H included in the 2021 IRP preferred portfolio?

A. Yes. In the 2021 IRP, after a variety of price-policy and coal retirement scenarios were considered, the P02-MM[5] portfolio was identified as top-performing and B2H was included in that portfolio. At that point, eight variants of P02-MM were prepared to analyze key resource and transmission decisions. As B2H was already part of the P02-MM portfolio, a "No B2H" portfolio was prepared that excluded B2H. The P02-MM portfolio, which includes B2H, was identified as the top-performing portfolio among all variants, including the variant that removed B2H.[6]

[5] In the 2021 IRP, the P02 series of portfolios reflect fully optimized coal unit retirements using the best available input data and assumptions regarding requirements and constraints. The P02-MM portfolio was selected assuming medium gas prices and a medium CO_2 price proxy for future federal policy.
[6] The 2021 IRP also identified additional resources related to compliance with Washington's Clean Energy Transformation Act ("CETA") that were added to establish the 2021 IRP preferred portfolio (P02-MM-CETA). The additional resources necessary to comply with CETA, however, are not treated as system resources for purpose of the IRP and had no impact on the need for B2H.

Q. Did the 2021 IRP modeling account for the interdependence of resources and transmission, like B2H?

A. Yes. The PLEXOS model used to develop the 2021 IRP, which I discuss in more detail below, has the ability to endogenously view costs and transmission capability associated with transmission upgrades and allows for selection of specific transmission investments that coincide with new resource options. Endogenous transmission modeling capabilities in the PLEXOS model include the consideration of 1) new incremental transmission options tied to resource options; 2) existing transmission rights tied to the use of post-retirement brownfield sites; 3) estimated costs associated with these transmission options; and 4) transmission options that interact with multiple or complex elements of the IRP transmission topology. When the 2021 IRP modeling evaluated transmission investments, it accounted for the assumed cost for those investments and the value generated by those investments by enabling low-cost resource options and better optimization of resources needed to serve load or to lower system costs.

Q. Please describe the reliability benefits from B2H that were identified in the 2021 IRP.

A. The 2021 IRP indicated that energy not served ("ENS") would be slightly higher in the absence of B2H. ENS is reported as an output of the PLEXOS model and it indicates the volume of load that could not be met do to a shortfall of supply in modeled load areas across PacifiCorp's system.

Q. Does the 2021 IRP fully capture the expected system reliability benefit associated with B2H?

A. No. The 2021 IRP reflects PacifiCorp's load, resources, and transmission rights, plus limited access to market purchases. In light of regional reliability concerns, discussed in Chapter 5 of the 2021 IRP, the maximum amount of market purchases available was reduced significantly from the level in the 2019 IRP. These reductions were applied in the summer season for the California-Oregon Border ("COB"), Nevada-Oregon Border ("NOB"), and Mona markets whose participants typically experience peak demand in the summer. For the Mid-Columbia ("Mid-C") market, the maximum amount of market purchases was reduced in both seasons, but by a larger amount in the winter season, as the Pacific Northwest is generally winter peaking. By enhancing the connection between the summer and winter-peaking areas of PacifiCorp's system, B2H will make it more likely that purchases can be procured from markets that are not experiencing peak conditions and delivered where they are needed (i.e., purchases imported to PacifiCorp's East BAA in the winter and purchases imported into PacifiCorp's West BAA in the summer). While modeled market purchase limits are representative of what might be available during peak demand conditions, there are many hours within summer and winter seasons in which regional demand is likely to support market transactions well in excess of those limits. Due to the market purchase limits, the reported results do not account for the entire improvement in reliability that B2H is likely to facilitate by providing additional access to distant markets.

Q. Will B2H increase PacifiCorp's reliance on market purchases?

A. No. Access to market purchases is not the same as reliance on market purchases. The P02-MM portfolio, which includes B2H has more resources as a result of higher interconnection capability provided by the Project. The addition of more resources generally reduces the need to rely on market purchases to serve customer load. This does not mean that market purchases will necessarily decline, as reduced congestion allows for more cost-effective market purchases to support customer load rather than more expensive dispatchable resources. To the extent dispatchable resources are called upon less often, but remain available as indicated by the increase in resources in the portfolio that includes B2H, PacifiCorp would not be reliant upon such purchases to meet its peak loads and reliability requirements.

V. 2021 IRP UPDATE

Q. Has the Company prepared an update to the 2021 IRP?

A. Yes. On March 31, 2022, the Company issued its 2021 IRP Update.

Q. What is the purpose of the 2021 IRP Update?

A. The 2021 IRP Update serves as a checkpoint to the action plan contained in the 2021 IRP to ensure that changes in the planning environment are considered in between the full IRP planning process, which is completed every two years. The 2021 IRP Update assesses whether evolving trends and events that may ultimately impact customers merit a shift in the action plan to deliver resources and transmission investments that might be needed to reliably serve customers. As relevant here, the 2021 IRP Update reflects resource planning and procurement activities that have occurred since the 2021 IRP and presents an updated load-and-resource balance and an updated resource portfolio consistent with changes in the planning environment.

Q. Was B2H considered in the Company's 2021 IRP Update?

A. Yes. B2H and associated resource interconnections it will enable were included in the preferred portfolio identified in the 2021 IRP Update.

Q. Did the 2021 IRP Update continue to show a need for additional transmission resources?

A. Yes. In fact, the need increased relative to the 2021 IRP, primarily due to an increase in forecasted load. While the same transmission options were available in the 2021 IRP Update as the 2021 IRP, the 2021 IRP Update included two new options and accelerated four others from the 2021 IRP.[7] This was partially offset by one delay and the removal of one option from the final year of the study horizon. There were no changes in the timing and need for B2H.

Q. Did the 2021 IRP Update continue to show a need for additional generation resources?

A. Yes. The resource need also increased due to an increase in forecasted load. The 2021 IRP Update shows a resource need in all years of the planning horizon—starting at 1,584 MW in 2022 and increasing to 6,755 MW in 2040.[8] In 2027, the first full year that B2H will be in service, the resource need is 2,403 MW, an increase of 273 MW, or approximately 13 percent, relative to the resource need identified in the 2021 IRP. The higher load reflected in the 2021 IRP Update approaches the level analyzed in the

[7] *See* 2021 IRP Update, Table 6.2

[8] *See* 2021 IRP Update, Table 4.2.

high-load sensitivity conducted in the 2021 IRP.[9] And, as discussed later in my testimony, the most recent load forecast is even higher than what was assumed in the 2021 IRP Update.

Q. What other important updates were included in the 2021 IRP Update modeling?

A. As discussed in Chapter 5 – Modeling and Assumptions Updates of the 2021 IRP Update, key updates in addition to the load-and-resource balance include the resource changes due to activity resulting from the 2020 All Source RFP. Importantly, the EPA's pre-publication version of its Ozone Transport Rule, which was released on March 11, 2022, was not modeled in the 2021 IRP Update.

Q. Did the 2021 IRP Update include the same with-and-without B2H analysis that you describe for the 2021 IRP?

A. Yes. Through 2040, the resource portfolio with B2H was $439 million lower cost on a risk-adjusted basis as compared to the portfolio without B2H.

VI. MODELING ASSUMPTIONS

Q. Please summarize the natural gas and CO_2 price assumptions used in the updated economic analysis of B2H in this case.

A. The updated economic analysis of B2H includes four price-policy scenarios, as summarized in Table 1:

- Medium natural gas prices paired with medium CO_2 prices, which I refer to as the "MM" price-policy scenario;
- Medium natural gas prices without a CO_2 price, which I refer to as the "MN" price-policy scenario;

[9] *See* 2021 IRP Update, Pg. 2.

- Low natural gas prices without a CO_2 price, which I refer to as the "LN" price-policy scenario; and
- High natural gas prices with a high CO_2 price, which I refer to as the "HH" price-policy scenario.

These assumptions can influence the value of system energy, the dispatch of system resources, and PacifiCorp's resource mix. Consequently, wholesale-power prices and CO_2 policy assumptions affect net power cost ("NPC") benefits, non-NPC variable-cost benefits, and system fixed-cost benefits associated with B2H. Because wholesale-power prices and CO_2 policy outcomes are both uncertain and important drivers to the economic analysis, it is important to evaluate a range of assumptions for these variables. Table 1 summarizes the price-policy scenarios used to analyze B2H.

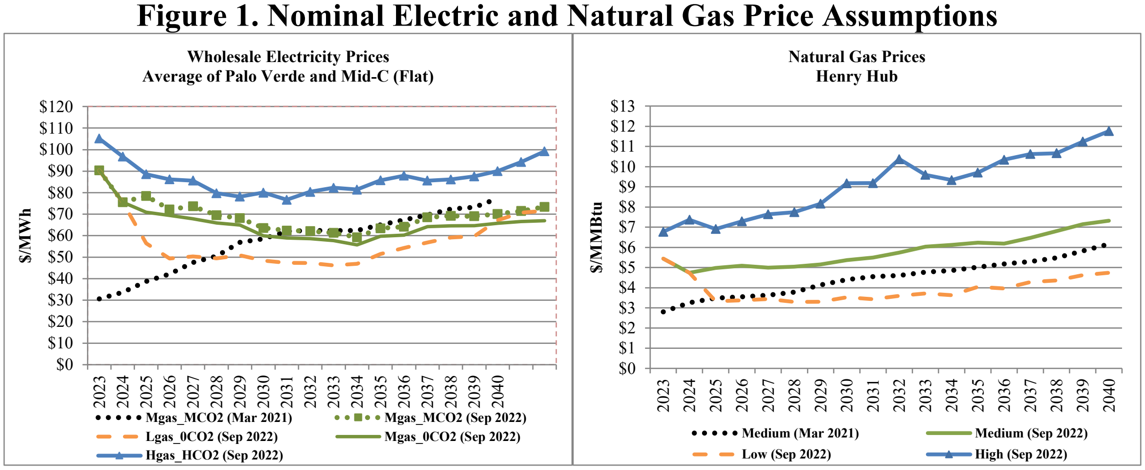
Table 1. Price-Policy Scenario Assumption Overview

Price-Policy Scenario	Henry Hub Natural Gas Price (Levelized $/MMBtu)*	CO_2 Price Description
MM	Medium Gas: $5.67	$12.10/ton starting 2025 rising to $51.40/ton in 2040
MN	Low Gas: $3.67	None
LN	Medium Gas: $5.67	None
HH	High Gas: $8.94	$44.34/ton starting 2025 rising to $120.48/ton in 2040
*Nominal levelized Henry Hub natural gas price from 2025 through 2040.		

Q. Please describe the natural gas price assumptions used in the price-policy scenarios.

A. The medium natural gas price assumptions are from PacifiCorp's official forward price curve ("OFPC") dated September 30, 2022, which was the most current OFPC available when PacifiCorp prepared its modeling inputs. The first 36 months of the OFPC reflect market forwards at the close of a given trading day (September 30, 2022, in this case). As such, these 36 months represent market forwards as of September 2022. The blending period (months 37 through 48) is calculated by averaging the month-on-month market forwards from the prior year with the month-on-month fundamentals-based price from the subsequent year. The fundamentals portion of the natural gas OFPC reflects an expert third-party price forecast. The fundamentals portion of the electricity OFPC reflects prices as forecast by a third-party using AURORAXMP ("Aurora"), a WECC-wide market model. Aurora uses the expert third-party natural gas price forecast to produce a consistent electricity price forecast for market hubs in which PacifiCorp participates. Figure 1 shows Henry Hub natural-gas price assumptions for the medium, high, and low natural gas price scenarios compared to the medium price used in the 2021 IRP forecast from March 2021. The electric prices comparison is also shown. The September 2022 price forecast reflects updates to natural gas prices that are higher in the near term from recent market price trends. The updated gas prices also account for limitations in west coast states to add new natural gas.

Figure 1. Nominal Electric and Natural Gas Price Assumptions

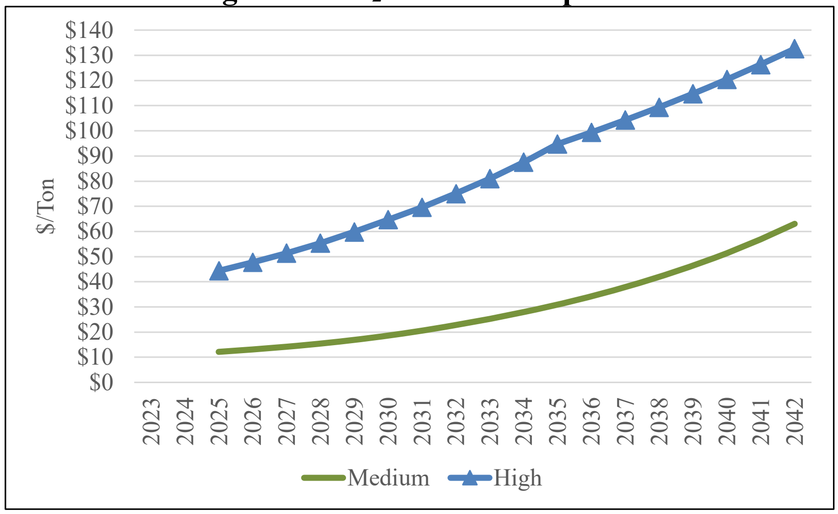


Q. Please describe the CO_2 price assumptions used in the price-policy scenarios.

A. PacifiCorp used three different system-wide CO_2 price scenarios—zero, medium, and high. The medium and high scenarios are derived from a survey of third-party industry experts, including IHS CERA, and Wood Mackenzie and the Energy Information Administration as well as CO_2 price assumptions used by peer utilities. The resulting CO_2 price is applied as a tax beginning in 2025, as shown in Figure 2.[10] In addition, the Company's Chehalis natural gas-fired plant is located in Washington and is subject to Washington's cap-and-invest program established in the Climate Commitment Act, which became effective January 1, 2023. As a proxy for the auction and trading process in this program, in all CO_2 scenarios the cost of emissions from the Chehalis plant reflect the social cost of greenhouse gases used for compliance with RCW 19.280.030 and incorporates the updated inflation forecast in the Washington Utility and Transportation Commission's August 24, 2022, order in docket U-190730.

[10] While the CO_2 price assumptions are applied as a tax, the inclusion of CO_2 prices in this way does not necessarily mean that future policies will specifically be implemented via a tax. Inclusion of a CO_2 price represents that there is a high likelihood that future policies will impute a cost on fossil-fired generation that is incremental to the cost of existing policies known today. Considering the difficulties in projecting future policy mechanisms, this incremental cost is applied for modeling purposes as a tax.

Figure 2. CO_2 Price Assumptions



Q. Does inclusion of potential future CO_2 costs reflect prudent utility planning?

A. Yes. The Company's price-policy scenarios include varying levels of assumed CO_2 costs to reflect the fact it is more likely than not that some policy will exist that will drive reduced emissions over the life of B2H and that these policies will introduce an incremental cost to fossil-fired generation. When determining CO_2 costs used for planning purposes, the Company strives to ensure that it is not an outlier. As discussed above, the medium price is within a reasonable range used by the industry to assess risk and conduct sound resource planning. The most recent example of this trend is the EPA's proposed Ozone Transport Rule restricting NO_x emissions from power plants and other industrial sources.[11] This rule could impose new and significant environmental compliance obligations, resulting in upward pressure on system costs, by 2026 on PacifiCorp's coal units in Wyoming and Utah.

[11] *See* https://www.epa.gov/csapr/good-neighbor-plan-2015-ozone-naaqs.

Q. Are the modeled CO_2 costs intended to represent a literal carbon tax?

A. No. The modeled CO_2 costs are not intended to explicitly account for a future tax on CO_2 emissions. Rather, these costs capture the effect of policies incentivizing reduced emissions through benefits or imposing costs through penalties or other costs resulting from market dynamics driving the need for reduced emissions from fossil-fired generation.

Q. Did PacifiCorp update its load forecast in its economic analysis of B2H?

A. Yes. The sales and load forecast used in preparation of this filing was completed in September 2022. It is the same load forecast that was presented at the October 13, 2022, public-input meeting for the 2023 IRP.

Q. How does this load forecast compare to the load forecast used in the 2021 IRP?

A. Figure 3 and Figure 4 show the load and peak forecast relative to the 2021 IRP forecast, both before accounting for incremental energy efficiency savings. The higher load forecast is being driven by new industrial and commercial customer growth, increased air conditioning saturations and miscellaneous devices and electric vehicle adoption expectations. The updated load forecast also includes updates to weather, temperature, and line losses to account for the progression of historical data since the load forecast that informed the 2021 IRP. The updated load forecast also incorporates certain tax changes resulting from the passage of the IRA.

On average, over the 2023 through 2040 timeframe, forecasted system load is up 12.9 percent per year and forecasted coincident system peak is up 13.6 percent per year when compared to the 2021 IRP. Over that same timeframe, the average annual growth rate for the September 2022 forecast, before accounting for incremental energy efficiency improvements, is 2.00 percent for load and 1.6 percent for peak.

Figure 3. Forecasted Annual System Load

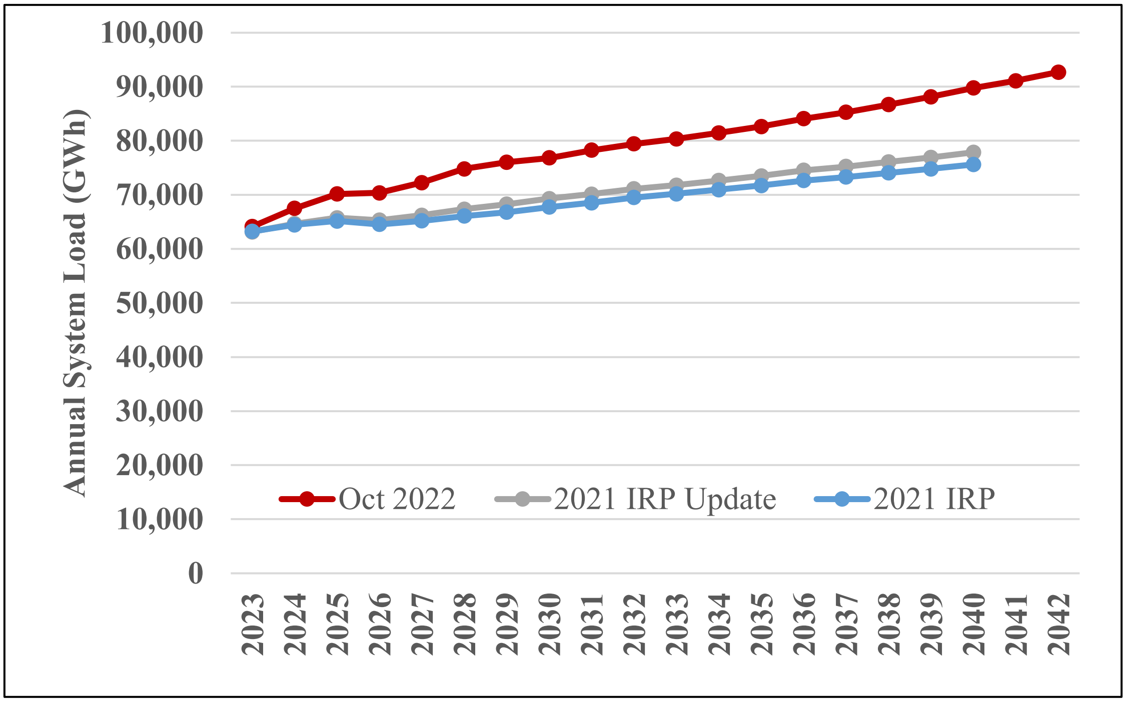
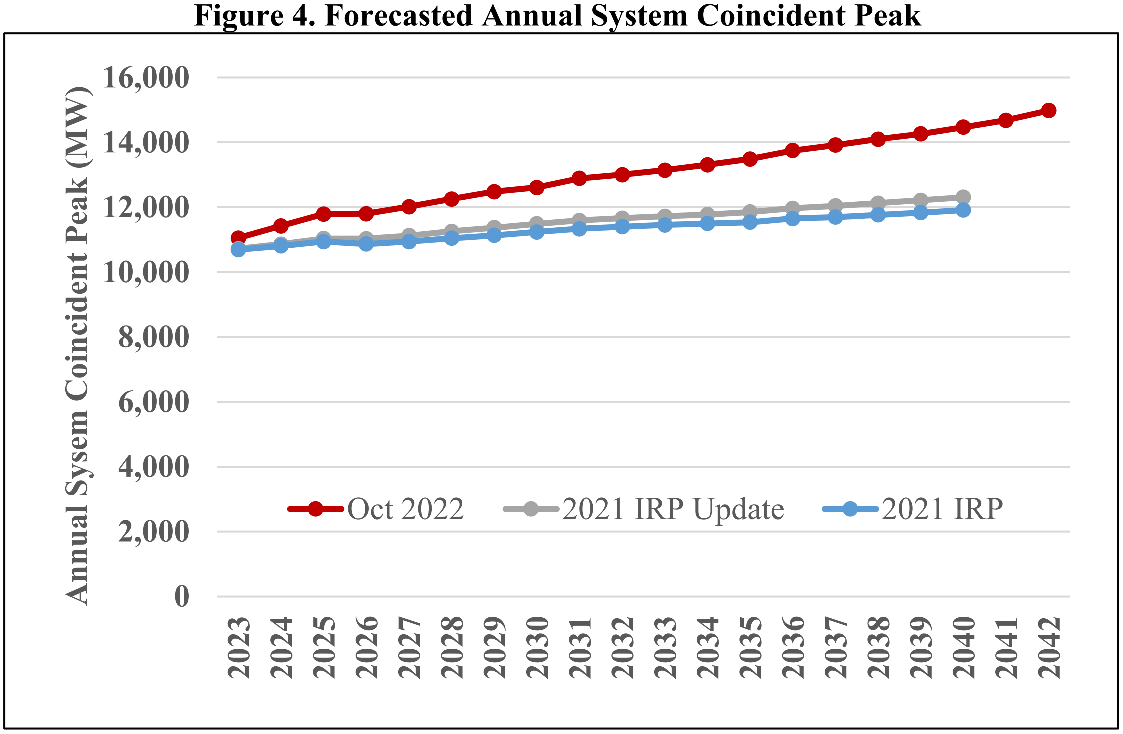


Figure 4. Forecasted Annual System Coincident Peak



Q. Has PacifiCorp incorporated EPA's proposed Ozone Transport Rule in its analysis of B2H?

A. Yes. PacifiCorp modeled two primary components to reflect the Ozone Transport Rule: NOx allowance requirements for each of its units including penalties for units with high emissions rates, and a market price for NOx allowances, based on the allowance price used in the third-party forecast to develop the September 2022 OFPC. After running the model, PacifiCorp compared the results to a forecast of its dynamic annual allocation of NOx allowances for Utah and Wyoming based on operations in earlier years.

Q. Please describe how the annual allocation of NOx allowances would work under the proposed rule.

A. The proposed rule calls for dynamic budgeting of NOx allowances in 2025 and beyond, with available allowances allocated among resources within a state based on the recent historical heat input and emissions rates of each resource. Under EPA's proposed rule, the forecasted allocation of NOx allowances drops significantly in 2026, as EPA assumed that selective catalytic reduction ("SCR") installations at eligible facilities would significantly reduce emissions by that year. PacifiCorp's thermal facilities in Utah and Wyoming would be covered by the rule.

While trading of NOx allowances among participating states is allowed, the proposed Ozone Transport Rule includes significant penalties if a state's emissions exceed 121 percent of its annual allocation, including three-for-one allowance surrender for emissions in excess of 121 percent. Limited banking of NOx allowances is also allowed, but emissions met via banked allowances may also be subject to penalties if a state's emissions exceed 121 percent of its annual allocation. To avoid such penalties, PacifiCorp's NOx emissions during the ozone season (May-September) in each state cannot exceed 121 percent of PacifiCorp's forecasted allocation of NOx allowances for that state.

Q. Please describe how PacifiCorp developed NOx allowance requirements for each of its units.

A. In general, an allowance for one ton of NOx emissions would allow the holder of the allowance to emit one ton of NOx. However, starting in 2027,[12] the proposed Ozone Transport Rule also imposes a daily NOx emissions rate limit of 0.14 lb/MMBtu for each coal-fired facility, and requires emitters to provide an equivalent of triple allowances for any emissions that exceed that rate. For example, a resource with an emissions rate of 0.20 lb/MMBtu would have an effective allowance requirement equivalent to an emissions rate of 0.32 lb/MMBtu.[13] In order to calculate PacifiCorp's NOx allowance requirements under the Ozone Transport Rule, starting in 2027 the modeled emission rates for coal resources whose emissions exceed 0.14 lb/MMBTU were grossed up to account for the additional surrender of allowances. Note that incremental allowances do not count toward the 121 percent state emissions limit, which is based on actual emissions, and not allowance requirements.

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[12] Coal units that currently have SCR installed must meet the daily backstop limit in 2024. Coal units that do not currently have SCR installed must meet the daily backstop limit in 2027.

[13] Effective allowance requirement for resource with emissions rate of 0.20 lb/MMBTU: 100% * 0.20 lb/MMBtu + 200% * (0.20 – 0.14) lb/MMBtu = 100% *0.20 + 200% * 0.06 = 0.32 lb/MMBtu.

Q. Please describe how PacifiCorp's modeling represents its NOx allowance requirements.

A. PacifiCorp's September 2022 market price forecasts incorporate a regional NOx allowance price, and this price is incorporated in several ways. First, PacifiCorp calculated its share of EPA's proposed allowance allocation for Utah and Wyoming in 2023 and 2024, and a projection of its share thereafter. To the extent emissions in a state are projected to exceed 121 percent of its estimated allocation, any incremental emissions are assumed to be subject to the three-for-one allowance surrender requirement, which is reflected in a cost per ton that is three times the September 2022 allowance price forecast. Because the state limits are based on emissions, the modeled emissions rates are not grossed-up starting in 2027 as described above. In addition, to the extent that overall allowances (not emissions) exceed 100 percent of PacifiCorp's projected allocation, then any incremental allowances are assumed to have a cost per ton that is equal to the September 2022 allowance price forecast. Because the PacifiCorp total requirement is based on allowances (not emissions), a distinct emissions rate is modeled which is grossed-up for emissions over 0.14 lb/MMBtu starting in 2027 as described above.

Under EPA's proposed rule, PacifiCorp will receive specified free allowances in 2023 and 2024. Starting in 2025 PacifiCorp will receive free allowances that are dynamically calculated based on heat input and emissions rates two years prior. Said another way, heat input and emissions that require an allowance today will result in a share of future allowances two calendar years later. The net present value of each unit's current year allowance requirement and its share of future year allowances is translated into an effective emissions rate for dispatch, ensuring that resources that will yield higher future benefits are dispatched ahead of those with lower future benefits, to the extent that those benefits outweigh any difference in fuel and variable costs.

Q. Please describe how PacifiCorp's NOx allowance requirements are incorporated in the reported system cost results.

A. The dynamic nature of the proposed Ozone Transport Rule complicates the modeling, because the feedback from prior year dispatch decisions is difficult to incorporate. However, after a study is complete, it is possible to calculate allowance needs and future year allowance allocations that are specific to the dispatch and emissions results in that study. Allowance requirements (inclusive of the gross-up for emissions over 0.14 lb/MMBTU starting in 2027) are summed up, and two additional allowances are added for any emissions in excess of 121 percent of the dynamically calculated emissions requirement for each state. After subtracting off the allowance allocation, unused allowances are banked up to the specified limits, and any remaining allowances are assumed to be sold at the September 2022 forecast of the allowance price. If the allowance allocation is lower than the allowance requirement, banked allowances are used and the remaining balance is assumed to be purchased at the September 2022 forecast of the allowance price.

VII. MODELING METHODOLOGY

Q. Please describe the modeling methodology PacifiCorp used in its analysis of B2H.

A. PacifiCorp calculated a system present-value revenue requirement ("PVRR") by identifying least-cost resource portfolios and dispatching system resources through 2042, which aligns with the 20-year forecast period used in PacifiCorp's forthcoming

2023 IRP. Net customer benefits are calculated as the present-value revenue requirement differential ("PVRR(d)") between different simulations of PacifiCorp's system. One simulation includes B2H and the other simulation excludes it, and the resulting differences in PacifiCorp's modeled transmission rights between the two simulations are summarized in Table 2 below.

Table 2. Modeled Transmission Associated with B2H

Maximum Transfer Capability (MW)	**No B2H**	**With B2H**
B2H Transfers		
Existing PAC Westbound	1090	1090
IPC PTP Westbound	510	510
B2H Westbound	0	818
Total Westbound	**1600**	**2418**
IPC PTP Eastbound	100	300
B2H Eastbound	0	300
Total Eastbound	**100**	**600**
IPC Asset Transfer		
Borah to Hemingway Westbound	n/a	To PacifiCorp
Borah to Hemingway Eastbound	n/a	To PacifiCorp
To Goshen (BPA load service)	n/a	To IPC
Borah to Four Corners Southbound	n/a	To IPC
Borah to Four Corners Northbound	n/a	To IPC
Central Oregon Load Service		
Southbound to Central Oregon load	340	340
Northbound to Central Oregon load	340	340
Enabled by:	*Southern Oregon Battery & implementation of flow-based scheduling*	*B2H*
Total Central Oregon	**680**	**680**

Longhorn Area Load Service		
West to Longhorn area load	*100%**	300
East to Longhorn area load	0	818

**Longhorn load is confidential. The associated costs are identified in Confidential Exhibit 2.*

Q. Why is PacifiCorp's share of B2H westbound capacity higher than its subscribed allocation of 600 MW?

A. The unsubscribed portion of B2H westbound capacity will be allocated between PacifiCorp and IPC based on their respective shares of the overall project. The value of 818 MW in Table 2 includes PacifiCorp's share of that unsubscribed capacity.

Q. Please describe the costs associated with the B2H transfer capability summarized above.

A. The cost of B2H, including associated equipment such as the Midline series compensation, is the largest element. While this cost will be included in PacifiCorp's rate base, it will also be recovered from third-party transmission customers of PacifiCorp Transmission, as part of its Open Access Transmission Tariff ("OATT") and annual formula rate update. As a result, approximately 80 percent of these costs are expected to be recovered from PacifiCorp's retail customers. This same percentage applies to all transmission upgrade options evaluated in PacifiCorp's IRP modeling. In the same way, because PacifiCorp uses IPC point-to-point ("PTP") transmission service to serve its retail customers, it will also pay for a portion of IPC's costs for the B2H project, through IPC's OATT rates and annual formula rate update process. This will be reflected in the rates for PacifiCorp's existing PTP reservations, and in the pending reservations that will be granted contingent upon B2H going into service.

Unlike transmission capital costs for PacifiCorp-owned assets, which are partly recovered through OATT rates, the expense for third-party wheeling reservations is part of NPC and is recovered from PacifiCorp's retail customers only.

Q. Please describe the costs associated with the IPC asset transfers summarized above.

A. PacifiCorp does not have sufficient available transfer capability from its PacifiCorp East BAA at Borah to the southern terminus of B2H at Hemingway. To access the incremental transfer capability associated with B2H, PacifiCorp is negotiating an asset transfer with IPC. Many of the associated transmission assets between Borah and Hemingway are already jointly owned by PacifiCorp and IPC, and PacifiCorp would receive a greater share both eastbound and westbound that is in line with its share of the transfer capability associated with the Project itself. In return, IPC would receive a share of transmission assets to provide bidirectional rights between Borah and Four Corners, as well as to reach BPA loads in the Goshen area. As a result of the transfer, BPA would take transmission service from IPC, rather than PacifiCorp, which would result in a loss of OATT transmission revenue for the Company. The associated change in long-term transmission reservations would flow through PacifiCorp's annual formula rate update and result in higher OATT rates. While PacifiCorp's retail customers would be a larger share of the remaining long-term reservations, it is still projected to be approximately 80 percent of the total. As a result, 80 percent of the lost revenue from BPA would be attributable to PacifiCorp retail customers, and the remainder would be collected from remaining OATT customers.

Q. Please describe the costs associated with the central Oregon load service as summarized above.

A. PacifiCorp currently has rights to serve up to 340 MW of central Oregon load via transfers on the Buckley-Summerlake 500-kV line either northbound or southbound. Because of growing loads in central Oregon, PacifiCorp is seeking to serve up to 680 MW of central Oregon load by scheduling both northbound and southbound concurrently, each at up to 340 MW. To provide this service, a series capacitor bank will be required at the Meridian substation, either with or without B2H being placed in service.

With B2H in service, no additional transmission upgrades would be required; however, PacifiCorp would be able to consolidate certain PTP reservations on BPA's system that are used to reach central Oregon loads, resulting in a reduction in its BPA wheeling expense. Because the expense for third-party wheeling reservations is part of NPC, one hundred percent of these savings would be attributed to PacifiCorp's retail customers.

In the absence of B2H, providing this level of central Oregon load service would require at least 725 MW of dispatchable generation in southern Oregon.[14] This dispatchable generation in southern Oregon would need to be deployed when power flows from PacifiCorp to central Oregon loads across paths operated by BPA exceeded specified levels. As this is based on regional load and resource conditions, which are

[14] A non-wires analysis performed by BPA, IPC, and PacifiCorp indicated that obtaining 680 MW of central Oregon load service capability in the absence of B2H would require dispatchable generation in Southern Oregon ranging from 725 MW to 1,450 MW to prevent impacts to other existing rated paths.

likely to evolve over time, there is no specific duration that can be assured of maintaining central Oregon load service at 680 MW. For this analysis, the No B2H case included an additional 725 MW of eight-hour battery storage with estimated annual fixed costs of $230 million in 2027, after accounting for the 30 percent investment tax credit available to energy storage resources in the IRA. Because the IRP analysis only includes PacifiCorp's transmission rights and forecasted usage, it cannot identify periods in which dispatchable southern Oregon generation would need to be deployed to address flows on regional transmission paths. Given this uncertainty, the battery storage duration was increased to eight hours from the four-hour assumption used for this element of the analysis in the 2021 IRP and the 2021 IRP Update. Considering these uncertainties, the 725 MW storage resource was not assumed to be available for economic dispatch within the PLEXOS model.

Q. Please describe the costs associated with the Longhorn area load service summarized above.

A. PacifiCorp's load in the vicinity of the Longhorn substation is anticipated to grow significantly. Serving this load will require PTP transmission service with BPA, Portland General Electric ("PGE"), and/or Umatilla Electric Cooperative ("UEC"). The expense for such third-party wheeling reservations is part of NPC, so one hundred percent of these costs would be attributed to PacifiCorp's retail customers. Because of their location in proximity to B2H, these loads could instead be served via a connection to B2H. Once B2H is completed, such a connection is forecasted to be in service in May 2027, and when it is in place, third-party PTP transmission service would no longer be required. Because the transmission system costs would be recovered as part of PacifiCorp's OATT and annual formula rate update, approximately 80 percent of these costs are expected to be recovered from PacifiCorp's retail customers.

Q. Please describe how third-party transmission expenses and revenues are calculated.

A. Table 3 below summarizes the assumptions used for each of the third-party transmission providers as well as PacifiCorp's revenue from BPA, under its OATT. The rates for PGE and UEC are relatively straightforward, reflecting escalation of the current rates at inflation. The rates for BPA reflect escalation of its current PTP and Schedule 1 rates (Scheduling, System Control and Dispatch) at 3.75 percent per year (7.5 percent over each two-year rate-effective period). The cost for BPA reservations is reduced by applicable short-distance discounts. For IPC and PacifiCorp, formula rate calculations also incorporate adjustments to include the cost of B2H (for both) and Gateway South ("GWS") for PacifiCorp, as these major transmission investments appreciably increase these rates. In addition, the formula rate calculations for both IPC and PacifiCorp are also adjusted for changes in long-term contractual demand, adding PacifiCorp's additional PTP reservations to IPC's calculation and removing BPA's load from PacifiCorp's calculation.

Table 3: Third-party Transmission Service Assumptions

Provider	Service	Schedules	Escalation	Adjusted Rate Base	Adjusted Demand
BPA	PTP+SCHED	PTP+ACS	3.75%	n/a	n/a
PGE	PTP	7	2.27%	n/a	n/a
UEC	PTP	11	2.27%	n/a	n/a
IPC No B2H	PTP	7	2.27%	n/a	+100 MW
IPC w/ B2H	PTP	7	2.27%	+B2H	+100 MW
PAC No B2H	NITS	NITS	2.27%	+GWS	n/a
PAC w/ B2H	NITS	NITS	2.27%	+GWS+B2H	-314 MW

Q. What modeling tool did PacifiCorp use to evaluate the B2H project?

A. Consistent with the 2021 IRP modeling, PacifiCorp used the PLEXOS model.

Q. Please describe the PLEXOS model.

A. The PLEXOS model provides three platforms of the PLEXOS tool (referred to as long-term ("LT"), medium-term ("MT") and short-term ("ST")), which work on an integrated basis to inform the optimal combination of resources by type, timing, size, and location over PacifiCorp's 20-year planning horizon. The PLEXOS tool also allows for endogenous modeling of resource options simultaneously, greatly reducing the volume of individual portfolios needed to evaluate impacts of varying resource decisions.

Q. Please describe how PacifiCorp used the LT model.

A. PacifiCorp used the LT model to produce a unique resource portfolio under MM price-policy conditions. The LT model portfolio is informed by an hourly review of reliability based on ST model simulations (described below). This ensures that each portfolio meets minimum reliability criteria in all hours. While the 2021 IRP and

2021 IRP Update both assumed that B2H would enable 600 MW of generator interconnection capability, recent generator interconnection study results do not indicate that the B2H project is directly required for pending interconnection requests. Therefore, PacifiCorp did not assume any generating resources would be enabled by B2H and did not make any resource changes between cases that included B2H and cases without it. While there are currently no pending interconnection requests that require B2H, future interconnection requests in the vicinity of B2H could still be contingent upon its completion.

Q. Please describe how PacifiCorp used the MT model.

A. PacifiCorp used the MT model to perform stochastic risk analysis of the portfolios. Each portfolio was evaluated for cost and risk for each price-policy scenario. A primary function of the MT model is to calculate an optimized risk-adjustment, representing the relative risk of a portfolio under unfavorable stochastic conditions for that portfolio.

Q. Please describe how PacifiCorp used the ST model.

A. PacifiCorp used the ST model to evaluate each portfolio to establish system costs over the entire 20-year planning period. The ST model accounts for resource availability and system requirements at an hourly level, producing reliability and resource value outcomes as well as a PVRR, which serves as the basis for selecting least-cost, least-risk portfolios. As noted above, ST model simulations were also used to identify the potential need for resources in the portfolio to maintain system reliability.

Q. How did each of the three PLEXOS models work together to inform the economic analysis presented here?

A. In the first step, a resource portfolio without B2H was developed using the LT model. The LT model operates by minimizing operating costs for existing and prospective new resources, subject to system load balance, reliability, and other constraints. Over the 20-year planning horizon, the model optimizes resource additions subject to resource costs and load constraints. These constraints include seasonal loads, operating reserves, and regulation reserves plus a minimum capacity reserve margin for each load area represented in the model.

To accomplish these optimization objectives, the LT model performs a least-cost dispatch for existing and potential planned generation, while considering cost and performance of existing contracts and new demand-side management ("DSM") alternatives within PacifiCorp's transmission system. Resource dispatch is based on representative data blocks for each of the 12 months of every year. Dispatch also determines optimal electricity flows between zones and includes spot market transactions for system balancing. The model minimizes the system PVRR, which includes the net present-value cost of existing contracts, market purchase costs, market sale revenues, generation costs (fuel, fixed and variable operation and maintenance, decommissioning, emissions, unserved energy, and unmet capacity), costs of DSM resources, amortized capital costs for existing coal resources and potential new resources, and costs for potential transmission upgrades.

Each portfolio developed by the LT model must have sufficient capacity to be reliable over the IRP's 20-year planning horizon. The resource portfolios reflect a combination of planning assumptions such as resource retirements, CO_2 prices, wholesale power and natural gas prices, load growth net of assumed private generation penetration levels, cost and performance attributes of potential transmission upgrades, and new and existing resource cost and performance data, including assumptions for new supply-side resources and incremental DSM resources.

Q. What is the next step in the modeling process?

A. In the second step, the Company conducted a reliability assessment using the ST model. The ST model begins with a portfolio of resources and transmission from the LT model that has not yet benefited from a reliability assessment conducted at an hourly level. The ST model is first run at an hourly level for 20 years in order to retrieve two critical pieces of data: 1) shortfalls by hour; and 2) the value of every potential resource to the system. This information is then used to determine the most cost-effective resource additions needed to meet reliability shortfalls, leading to a reliability-modified portfolio. The ST model is then run again with the modified portfolio to calculate an initial PVRR, which is risk-adjusted by outcomes of MT model stochastics that occurs in the third step of the process.

Q. Please describe how the MT model is used to conduct cost and risk analysis.

A. In the third step, the resource portfolios developed by the LT model and adjusted for reliability by the ST model are simulated in the MT model to produce metrics that support comparative cost and risk analysis among the different resource portfolio alternatives. The stochastic simulation in the MT model produces a dispatch solution that accounts for chronological commitment and dispatch constraints. The MT simulation incorporates stochastic risk in its production cost estimates by using the

Monte Carlo sampling of stochastic variables, which include load, wholesale electricity and natural gas prices, hydro generation, and thermal unit outages. The MT results are used to calculate a risk adjustment which is combined with ST model system costs to achieve a final risk-adjusted PVRR.

Q. Is the PLEXOS model appropriate for analyzing the customer benefits of B2H?

A. Yes. The PLEXOS model is the appropriate modeling tool when evaluating significant capital investments that influence PacifiCorp's portfolio and affect least-cost dispatch of system resources. The LT model is needed to understand how the type, timing, and location of future resources might be coordinated to cost-effectively serve customer load. The ST and MT models provide additional granularity on how B2H is projected to affect system operations, including its impact on stochastic risks. Together, the LT, MT, and ST models are well suited to perform a benefit analysis for B2H that is consistent with long-standing least-cost, least-risk planning principles applied in PacifiCorp's IRP and resource procurement activities.

Q. When developing resource portfolios with the PLEXOS model, did you perform a reliability assessment?

A. Yes. As described above, the ST model was used to establish system costs for the entire 20-year planning period. The ST model accounts for resource availability and system requirements at an hourly level, producing reliability and resource value outcomes that will reveal whether an initially reliable portfolio selected by the LT model leaves shortfalls at an hourly level, which can then be addressed.

Q. Did PacifiCorp analyze how other assumptions affect its economic analysis of the B2H project?

A. Yes. PacifiCorp analyzed the B2H project under four price-policy scenarios.

VII. PRICE-POLICY SCENARIO RESULTS

Q. Please summarize the PVRR(d) results calculated from the PLEXOS model.

A. Table 4 summarizes the risk-adjusted PVRR(d) results for each price-policy scenario. The data that was used to calculate the PVRR(d) results shown in the table are provided as Confidential Exhibit No. 2

Table 4. PVRR(d) Cost/(Benefit) of B2H ($ million), 2023-2042

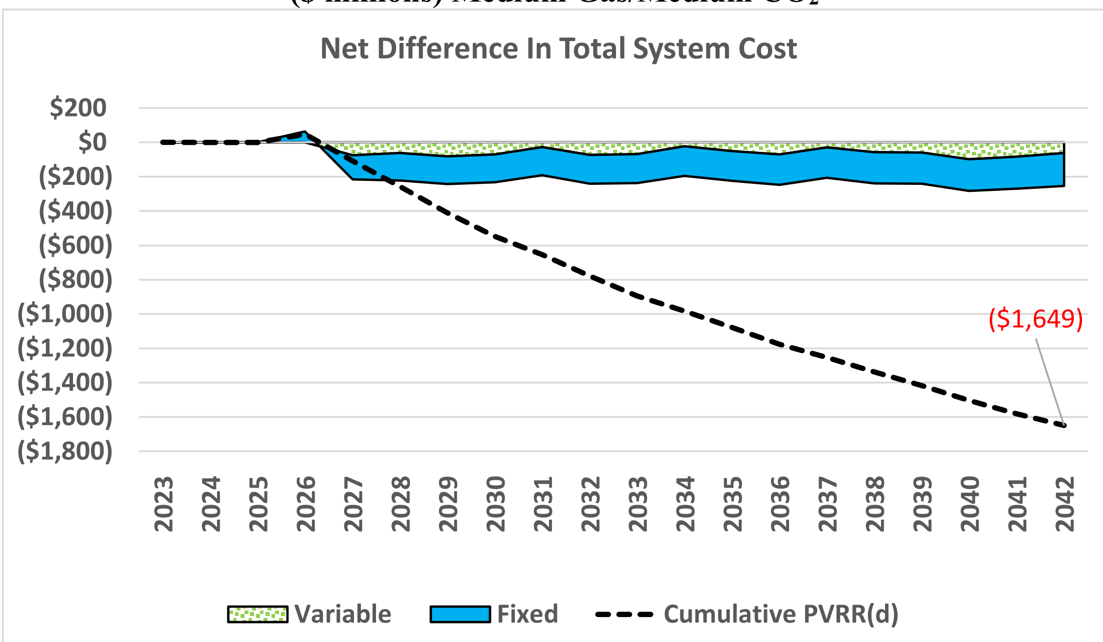
Price-Policy Scenario	B2H	Asset and Reservation Exchange	System Dispatch Impacts	Central Oregon Load Service	Longhorn Area Load Service	Total
MM	$454	$308	($520)	($1,811)	($143)	($1,713)
MN	$454	$308	($594)	($1,811)	($143)	($1,786)
LN	$454	$308	($488)	($1,811)	($143)	($1,680)
HH	$454	$308	($295)	($1,811)	($143)	($1,487)

As shown above, system costs are lower when B2H is included in the portfolio in all price-policy scenarios. The majority of the benefits are derived from the fixed cost of providing central Oregon load service, which are substantially lower as a result of B2H being placed into service. Both central Oregon load service and Longhorn area load service are solely comprised of fixed costs that are not impacted by system dispatch or the price-policy scenario assumptions.

Q. How do system costs change with and without B2H over time?

A. Figure 5 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when B2H is eliminated from the portfolio. The graph shows annual net changes in fixed and variable costs and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2042, the PVRR(d) shows that the portfolio that includes B2H is $1,649 million lower cost than the portfolio without B2H, before accounting for risk.

Figure 5. Increase/(Decrease) in System Costs when B2H is Included in the Portfolio ($ millions) Medium Gas/Medium CO_2



IX. ANNUAL REVENUE REQUIREMENT

Q. In addition to the modeling used to calculate present-value net benefits over a 20-year planning period, has PacifiCorp forecasted the change in nominal revenue requirement due to B2H?

A. Yes. The system PVRR from the PLEXOS model was calculated from an annual stream of forecasted revenue requirement over the period 2023 through 2042. The annual stream of forecasted revenue requirement captures nominal revenue requirement for non-capital items (*i.e.*, NPC, fixed operations and maintenance, PTCs, etc.) and levelized revenue requirement for capital expenditures. To estimate the annual revenue-requirement impacts of B2H, capital costs need to be considered in nominal terms (*i.e.*, not levelized).

Q. Why is the capital revenue requirement used in the calculation of the system PVRR from the PLEXOS model levelized?

A. Levelization of capital revenue requirement is necessary in these models to avoid potential distortions in the economic analysis of capital-intensive assets that have different lives and in-service dates. Without levelization, this potential distortion is driven by how capital costs are included in rate base over time. Capital revenue requirement is generally highest in the first year an asset is placed in service and declines over time as the asset depreciates. In the context of long-term resource planning that is conducted over a finite planning horizon, this can inappropriately favor less capital-intensive assets or assets with longer lives even if those assets might increase system costs over their remaining life.

Q. How did PacifiCorp forecast the annual revenue-requirement impacts of B2H?

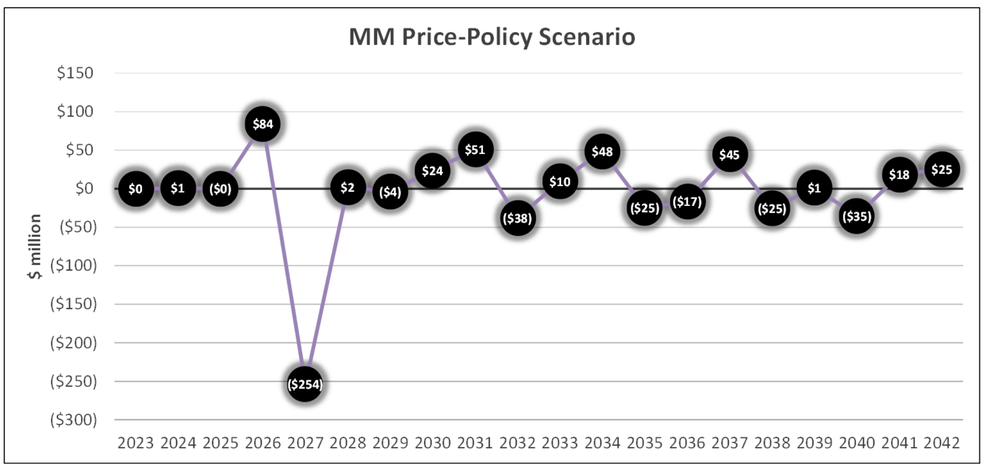
A. For each simulation, the annual stream of levelized revenue requirement associated with the initial capital for each resource and transmission addition, including B2H, is recalculated as a nominal revenue requirement through 2042, which aligns with the modeled study horizon. Since this change only applies to the cost stream associated with initial capital, all other costs that are part of the annual revenue requirement (e.g. fuel, market transactions, emissions), are unchanged from the modeled results.

Q. Please describe the change in annual nominal revenue requirement from B2H.

A. Figure 6 shows the estimated change in annual nominal-revenue requirement due to

B2H for the MM price-policy scenario on a total-system basis. The annual revenue requirement shown in the figure reflects all costs for B2H, including capital revenue requirement (*i.e.*, depreciation, return, income taxes, and property taxes), operations and maintenance expenses, net of avoided transmission costs, changes to wheeling expenses and revenues, and transmission revenue credits. The project costs are netted against system impacts of B2H, reflecting the change in NPC, emissions, non-NPC variable costs, and system fixed costs that are enabled by, but not directly associated with, the incremental transfer capability from B2H.

Figure 6. Total-System Change in Annual Revenue Requirement Due to B2H ($ million)



In 2027, the first full year that B2H is in service, the total-system nominal revenue requirement decreases by $254 million. Thereafter, while the net change in revenue requirement from year to year shows modest variation, B2H continues to enable a lower overall revenue requirement through the end of the study horizon.

X. AGREEMENTS RELATED TO B2H

Q. Do agreements relating to B2H remain outstanding?

A. Yes. As relevant to my testimony, there are several agreements between PacifiCorp's merchant function and IPC and BPA. First, the following transmission service requests will be executed or changes to existing transmission services agreements will be made:

- IPC will acquire from BPA 500 MW of PTP transmission service from Mid-C to Longhorn,
- PacifiCorp will renew its 510 MW of PTP transmission service from IPC, as shown in the line-item Idaho Power PTP Westbound in Table 2,

Second, BPA will redirect and then assign to PacifiCorp 200 MW of PTP transmission rights it holds on IPC's system. In particular, upon B2H energization, BPA has agreed to submit redirect requests to IPC for BPA's two existing 100 MW conditional firm PTP service agreements on IPC's system, with each having a new point of receipt of Walla Walla and a new point of delivery of Borah. Once the redirects have been approved and granted by IPC, BPA will assign the redirected service agreements to PacifiCorp. This is reflected in Table 2 in the 200 MW increase in the line-item IPC PTP eastbound.

Third, PacifiCorp and BPA will amend the Midpoint-Meridian Agreement to remove PacifiCorp's legacy scheduling rights over Buckley-Summerlake 500-kV line (North-to-South or South-to-North for up to 340 MW), thereby facilitating the revisions to the PTP service discussed below. This is reflected in Table 2 in the central Oregon load service section.

Fourth, PacifiCorp will update multiple PTP service agreements with BPA to reflect expansion of its central Oregon load service. The revisions will accommodate, upon B2H energization, 680 MW of firm PTP transmission rights into PacifiCorp's 230-kV system at points of delivery at Ponderosa 230-kV and Pilot Butte 230-kV. This is reflected in Table 2 in the central Oregon load service section.

XI. CONCLUSION

Q. Please summarize the conclusions of your direct testimony.

A. PacifiCorp's analysis shows that B2H is necessary and in the public interest, supporting the issuance of the requested CPCN.

Q. Does this conclude your direct testimony?

A. Yes.