Docket No. UE 433
Exhibit PAC/800
Witness: Rick T. Link

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Rick T. Link

February 2024

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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 Pacific Power (PacifiCorp or 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, I am responsible for the economic analysis used to screen system resource investments and conducting competitive request for proposal (RFP) processes, consistent with applicable state procurement rules and guidelines.

Q. Briefly describe your education and professional experience.

A. I joined PacifiCorp in December 2003 and assumed the responsibilities of my current position in September 2021. I have held several analytical and leadership positions responsible for developing long-term commodity price forecasts, pricing structured commercial contract opportunities and developing financial models to evaluate resource investment opportunities, negotiating commercial contract terms, and overseeing development of PacifiCorp's resource plans. I have been heavily involved in developing PacifiCorp's IRPs since 2013; have been directly involved in several 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 from Duke University in 1999.

Q. Have you testified in previous regulatory proceedings?

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

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your direct testimony?

A. I provide economic analysis that supports PacifiCorp's decision to build two transmission projects, including: (1) Gateway South, a 414-mile, 500-kilovolt (kV) overhead transmission line between the Aeolus Substation, near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah; and (2) Gateway West Segment D.1, a 59-mile, 230-kV transmission line from the Shirley Basin substation in southeastern Wyoming to the Windstar substation near Glenrock, Wyoming and the accompanying ancillary facilities (collectively, the Transmission Projects).

I also summarize PacifiCorp's assessment of the projects from the 2021 IRP and 2021 IRP update, provide background on PacifiCorp's 2020 All-Source Request for Proposal (2020AS RFP) to solicit new resources, including those enabled by the Transmission Projects, and discuss customer benefits that result from the projects.

For details regarding Gateway South and Gateway West, please refer to the direct testimony of Company witness Richard A. Vail.

Q. Please summarize your testimony for the Transmission Projects.

A. The 2021 IRP confirmed that the Transmission Projects remain a key transmission investment that will enable the procurement of low-cost wind facilities to reliably meet the Company's need for additional resources. These resources are expected to produce significant customer benefits. This includes ensuring that all new wind resources from the 2020AS RFP that depend on the Transmission Projects: (1) qualify for 110 percent of available federal production tax credits (PTC), further reducing the cost of these resources (that already have no fuel costs or emissions) relative to other resource options; and (2) generate renewable-energy certificates (RECs) that can be used to offset revenue requirements where appropriate.

As discussed by Company witness Vail, the Transmission Projects will also provide critical voltage support to the Wyoming transmission network, improve overall reliability of the transmission system, and enhance PacifiCorp's ability to comply with mandated reliability and performance standards. Most importantly, the Transmission Projects ensure the Company will meet its obligations to reliably accommodate nearly 2,500 megawatts (MW) of interconnection and transmission service requests, including 13 executed interconnection service and transmission service agreements for over 1,600 MW of new wind resources. This includes 500 MW of firm point-to-point (PTP) transmission service to a third-party transmission customer under the Federal Energy Regulatory Commission's (FERC) jurisdiction. Moreover, the Transmission Projects create additional opportunity to increase transfer capability with the construction of additional segments of the Energy Gateway project.

Q. Please summarize your economic analysis of the Transmission Projects.

A. My economic analysis demonstrates that the Transmission Projects are necessary and in the public interest. In my analyses, I reviewed the change in revenue requirement due to the Transmission Projects, and associated resources that are dependent upon the Transmission Projects, using the Company's IRP modeling tool across five different scenarios that pair varying natural gas price assumptions with varying carbon dioxide (CO_2) policy assumptions (price-policy scenarios). For each price-policy scenario, I calculated the change in system revenue requirement between cases with and without the Transmission Projects through 2040, where capital revenue requirement is levelized. The price-policy scenarios include:

- Medium natural gas prices paired with medium CO_2 prices (MM);
- Medium natural gas prices without a CO_2 price (MN);
- High natural gas prices paired with high CO_2 prices (HH);
- Low natural gas prices without a CO_2 price (LN); and
- The Social Cost of Greenhouse Gas (SCGHG).

These analyses confirm that the Transmission Projects are expected to generate customer benefits. Under the MM price-policy scenario, the present-value revenue requirement differential (PVRR(d)) customer benefit when using the most conservative assumptions for unavoidable transmission is $128 million and the risk-adjusted PVRR(d) benefits are $260 million. When assuming the cost of the Transmission Projects are unavoidable, the PVRR(d) under the MM price-policy scenario yields a $610 million customer benefit and a risk-adjusted benefit of $742 million. Conservatively, these benefits do not assign any value to the RECs that will be generated by new resources made available due to the Transmission Projects. The risk-adjusted results indicate that the Transmission Projects add significant risk mitigation benefits associated with volatility in market prices, loads, hydroelectric generation, and unplanned outages.

Q. Did you develop an additional calculation to measure how changes in cost might influence customer benefits?

A. Yes. I produced a calculation to determine how changes in resource and transmission cost assumptions would impact customer benefits. My review of resource costs show that assumed initial capital costs would need to increase by 32 percent to erode the customer benefits from the MM price-policy scenario. Similarly, the cost of the Transmission Projects would need to increase by 50 percent to erode the benefits from the MM price-policy scenario. These results show that the projected customer benefits are robust, and that they persist even if the resource costs and transmission costs far exceed the estimates that were available when we committed to move forward with the Transmission Projects.

Q. Did you continue to review the economic analysis after the Company began construction of the Transmission Projects?

A. Yes. I revisited the economic analysis as we were finalizing contracts for the wind resources dependent upon the Transmission Projects. This update accounted for, among other things, higher costs, higher PTC values associated with the passage of the Inflation Reduction Act (IRA), and the potential impacts of the Ozone Transport Rule (OTR). This review showed risk-adjusted customer benefits totaling $247 million in the MM price-policy scenario.

Q. Do you believe your testimony supports the prudency of the Company's investments for both Transmission Projects?

A. Yes.

III. GATEWAY SOUTH AND GATEWAY WEST SEGMENT D.1

A. Need

Q. Did the 2021 IRP identify the need for additional resources to serve PacifiCorp's customers?

A. Yes. The primary focus of the 2021 IRP is to forecast the need for resources and then evaluate different ways to meet that need over time. In the 2021 IRP, the assessment of resource need is presented in Volume I, Chapter 6. The load-and-resource balance shows that PacifiCorp has a capacity deficit in all years of the planning horizon—starting at 1,071 MW in 2021, and increasing to over 6,600 MW by 2040.[1] In 2025, the first full year that the Transmission Projects will be online, the resource need is 1,627 MW. Consistent with prior IRPs, all resource portfolios produced in the 2021 IRP that were considered as candidates for the preferred portfolio contain new supply-side, demand-side, and market resources to fill this need.

This need has continued to increase due to increases in forecasted load. The 2021 IRP Update shows a resource need in all years of the planning horizon—starting

[1] *See* PacifiCorp 2021 Integrated Resource Plan, Vol. I, Table 6.12.

at 1,584 MW in 2022 and increasing to 6,755 MW in 2040.[2] In 2025, the first full year that the Transmission Projects will be online, the resource need is 1,867 MW, an increase of 240 MW or approximately 15 percent from the 2021 IRP. The higher load reflected in the 2021 IRP Update approaches the level analyzed in the high-load sensitivity conducted in the 2021 IRP.[3]

Since the Company initiated construction of the Transmission Projects, national tariff policies, global supply-chain issues, and inflationary pressures eliminated some bids on the 2020AS RFP final shortlist. Consequently, PacifiCorp's procurement was reduced by 902 MW of solar resources and 497 MW of battery storage resources. Additional resources are needed to reduce PacifiCorp's reliance on the market.

Q. Why is it important to reduce PacifiCorp's reliance on market purchases?

A. There is a strong consensus that the western United States will face an increasing capacity deficit in the near future.[4] For example, in December 2020, the Western Electricity Coordinating Council (WECC) issued its Western Assessment of Resource Adequacy Report (WARA).[5] The WARA was developed based on data collected from balancing authorities describing their own demand and supply projections over the next 10 years. The WARA evaluated resource adequacy among six subregions under two scenarios—one with and without imports to the subregion. PacifiCorp serves load in three of these subregions—Northwest Power Pool Northwest (NWPP-

[2] *Id.* at Table 4.2.
[3] *Id.* at 2.
[4] *Id.* at Vol. I, Ch. 5.
[5] *The Western Assessment of Resource Adequacy Report,* Western Electricity Coordinating Council (Dec. 18, 2020) (https://www.wecc.org/Administrative/Western%20Assessment%20of%20Resource%20Adequacy%20Report%2020201218.pdf).

NW), Northwest Power Pool Northeast (NWPP-NE), and Northwest Power Pool Central (NWPP-C). For each of these scenarios, the WARA considered variations of supply. The most conservative assumes availability of only existing resources, and the most liberal includes availability of new resources under construction, those expected to come online, and those under development. The study found that for each of the three subregions in which PacifiCorp serves load, imports are needed to meet a one-day in 10-year planning threshold. The WARA shows that the NWPP-NW subregion would fall short of the planning threshold in 194 hours (under the most liberal supply case) to 208 hours (assuming availability of only existing resources) without imports. In the NWPP-NE and NWPP-C subregions, the study found that planning threshold is not met in 4,200 hours without imports.

These findings highlight that there are real reliability risks associated with relying on supply being available in the market to meet projected load obligations. In addition, WECC's 2021 WARA issued December 2021 further concludes that not only are resource adequacy risks to reliability likely to increase over the next 10 years, it recommends entities take immediate action to mitigate near-term risks and prevent long-term risks. The 2021 WARA projects that "by 2025, each subregion, and the interconnection, will be unable to meet the 99.98%-one-day-in-ten-year-reliability threshold."[6]

[6] *2021 Western Assessment of Resource Adequacy Report*, Western Electricity Coordinating Council (Dec. 17, 2021) (https://www.wecc.org/Administrative/WARA%202021.pdf).

Q. Are there any other third-party studies confirming the resource adequacy concerns in the west?

A. Yes. In December 2020, the North American Electric Reliability Corporation (NERC) issued its Long-Term Resource Adequacy (LTRA) study that included its 10-year WECC region reliability assessment.[7] The NERC LTRA calculates an anticipated resource-based reserve margin to a reference reserve margin to establish one of three risk determinations—adequate (anticipated margin exceeds the reference margin), marginal (anticipated margin is below the reference margin, but new resources under development could cover the shortfall), and inadequate (anticipated reserve margin is below the reference margin and load interruption is likely).

The NERC LTRA shows that the Northwest Power Pool region and Rocky Mountain Reserve Group regions are projected to be inadequate beginning in 2028 even if resources under development come online. Again, these findings highlight the risk of relying on other entities in the region to have excess supply available for the market when PacifiCorp may be required to buy power to serve its customers.

Q. How did the 2021 IRP preferred portfolio address the need for new resources?

A. The 2021 IRP preferred portfolio represented PacifiCorp's least-cost, least-risk plan to reliably meet customer demand over a 20-year planning period, based on the information available at the time the plan was developed. Using a range of cost and risk metrics to evaluate numerous resource portfolios, PacifiCorp selected a preferred portfolio that reflected a cost-conscious plan with near-term investments in renewable resources that capture tax credits before they expire or decrease, and new

[7] *2020 Long-Term Reliability Assessment*, North American Electric Reliability Corporation (Dec. 2020) (https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2020.pdf).

transmission infrastructure to facilitate the interconnection and delivery of these resources. These new resources and transmission investments are lower cost than other resource and transmission alternatives and are necessary to reliably serve our customers.

Q. Were the Transmission Projects part of the 2021 IRP preferred portfolio?

A. Yes. As described in Volume I, Chapter 4 of the 2021 IRP, the preferred portfolio includes both Gateway South and Gateway West Segment D.1. In the 2021 IRP, the Transmission Projects are assumed to be placed in service by the end of 2024, consistent with current construction timelines discussed by Company witness Vail. The Transmission Projects will enable the addition of new wind facilities that contribute to meeting 1,627 MW of projected resource need beginning 2025.

Q. Did the Commission acknowledge the Transmission Projects in the 2021 IRP?

A. Yes, and the Commission noted that it expected PacifiCorp to provide adequate analyses of the costs and benefits of transmission projects in future proceedings.[8] I believe my testimony provides the appropriate economic analyses to inform the Commission's request on this issue.

Q. Were the Transmission Projects part of the 2021 IRP Update?

A. Yes.[9]

Q. What new transfer capabilities and interconnection capacity do the Transmission Projects add to PacifiCorp's system?

A. The Transmission Projects will increase the transfer capability between the Aeolus

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[8] Order No. 22-178 (May 23, 2022).

[9] PacifiCorp's 2021 Integrated Resource Plan Update, Ch. 7, Action Plan Item 3a–3b, at 103–104 (Mar. 31, 2022) (https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021_IRP_Update.pdf).

substation in eastern Wyoming and the Clover substation located near Mona, Utah by 1,700 MW, and enable the interconnection of 2,030 MW of new resources in eastern Wyoming.

Q. Please describe key factors supporting the inclusion of the Transmission Projects as prudent investments in this case.

A. The Transmission Projects allow PacifiCorp to implement system improvements, support the full capacity rating of Gateway South and West, and enable the addition of incremental Wyoming renewable resources to support customer needs and deliver value for customers in the most cost-effective way. As discussed by Company witness Vail, the Transmission Projects will also improve overall reliability of the transmission system, and enhance PacifiCorp's ability to comply with mandated reliability and performance standards. Importantly, at the time PacifiCorp committed to move forward with building these new transmission assets, the Transmission Projects would ensure the Company could meet its obligations to reliably accommodate nearly 2,500 MW of interconnection and transmission service requests, including 13 executed interconnection service and transmission service agreements for over 1,600 MW of new wind resources. This included 500 MW of firm PTP transmission service to a third-party transmission customer under the FERC's jurisdiction.

Q. Please describe the reliability benefits of the Transmission Projects.

A The Transmission Projects directly connect eastern Wyoming to central Utah while enhancing reliability throughout PacifiCorp-served regions. Connecting to the Mona/Clover market hub provides additional flexibility in the use of least-cost resources from eastern Wyoming or southern Utah.

Moreover, allowing additional generation resources to interconnect and serve load will lessen PacifiCorp's reliance on volatile and potentially diminishing market transactions to serve load. Given concerns over regional resource adequacy, reducing reliance on the market ensures a stable and reliable supply of capacity and energy going forward.

In addition, Gateway South improves reliability by relieving the stress on the transmission system in eastern Wyoming and central Utah. Gateway South relieves stress on the underlying 230-kV transmission system in Wyoming, and it unloads the underlying 345-kV transmission system in central Utah, improving reliability in both regions. Essentially, the 500-kV line brings two distant areas closer to each other in a way that improves regional reliability.

Gateway West Segment D.1 creates a new transmission path that allows for additional resource development in the area. The addition of this line improves the reliability of the transmission system during certain identified outage conditions (Dave Johnston to Amasa 230-kV outage or Amasa – Shirley Basin 230-kV outage). Gateway West Segment D.1 is also a prerequisite for interconnecting new resources, including those selected in the 2020AS RFP. Company witness Vail's testimony addresses transmission system reliability and interconnection issues in greater detail.

B. <u>The 2020AS RFP</u>

Q. Please provide an overview of the 2020AS RFP.

A. The 2020AS RFP was issued to identify resources that could meet the Company's projected resource need identified in the 2019 IRP. Based on the cost-and-performance assumptions for proxy resources in the 2019 IRP, the Company expected that new wind, solar and battery energy storage systems (BESS) were likely to be the most cost-competitive types of resources offered into the 2020AS RFP. However, bidders could offer proposals for other types of resources (*i.e.*, natural gas, pumped storage, *etc.*).

Q. When was the 2020AS RFP issued?

A. After receiving approval from the Utah Commission (docket 20-035-05) and Oregon Commission (docket UM 2059), PacifiCorp issued the 2020AS RFP on July 7, 2020.[10]

Q. What was the market response to the 2020AS RFP?

A. There was a robust market response that resulted in over 28,000 MW of conforming bids, with an additional 12,500 MW of non-confirming bids. Bids for 24 projects totaling over 9,000 MW of resource capacity located in eastern Wyoming were submitted.

Q. How did the Company evaluate submitted bids?

A. The Company created an initial shortlist that was made public on October 29, 2020. This shortlist included 5,453 MW of renewable resource capacity: 2,974 MW of solar or solar with storage (1,130 MW of battery storage), 2,479 MW of wind, and 200 MW of standalone BESS. PacifiCorp then initiated a capacity factor evaluation

[10] In Oregon Administrative Rules 860-89-0010, et seq., the Oregon Commission has established competitive bidding requirements for certain resource acquisitions by Oregon's investor-owned utilities. *In the Matter of the Rulemaking Regarding Allowances for Diverse Ownership of Renewable Energy Resources*, Docket No. AR 600, Order No. 18-324, Appendix A (Aug. 30, 2018) (https://apps.puc.state.or.us/orders/2018ords/18-324.pdf). In addition, Utah's Energy Resource Procurement Act requires a competitive solicitation process before the acquisition of renewable resources greater than 300 MW *See* Utah Code Ann. § 54-17-201 *et. seq.*

process (performed by third-party expert WSP Global). The initial shortlist contained a mix of various ownership structures, including proposals for power-purchase agreements (PPAs), build-transfer agreements (BTAs), and battery storage agreements (BSAs).

Q. What resources were selected to the final shortlist?

A. After evaluating a range of potential bid portfolios, and accounting for bid updates from interconnection study results, the final shortlist included: 1,792 MW of new wind capacity (590 MW as BTAs and 1,202 as PPAs); 1,302 MW of solar capacity as PPAs; 697 MW of BESS (497 MW of BESS capacity paired with solar bids, and 200 MW as standalone BESS capacity as a BSA).[11]

Q. Which final shortlist resources depend on the Transmission Projects for interconnection?

A. Six final shortlist resources, representing over 1,600 MW of wind generation, require the Transmission Projects to interconnect to PacifiCorp's transmission system. Table 1 summarizes the wind resources that require the Transmission Projects to achieve interconnection.

[11] The final shortlist originally included an additional solar bid collocated with BESS. Shortly after the bidder was notified its project was on the final shortlist, it withdrew the bid from the 2020AS RFP. This bid is not included in the total capacity.

Table 1. 2020AS RFP Wind Bids Dependent on the Transmission Projects for Interconnection

Project	Bidder	Structure	Capacity (MW)
Cedar Springs IV	NextEra	PPA	350
Boswell Springs	Innergex	PPA	320
Two Rivers	BlueEarth Renewables LLC and Clearway Renew LLC	PPA	280
Anticline	NextEra	PPA	101
Rock Creek I	Invenergy	BTA	190
Rock Creek II	Invenergy	BTA	400

Q. Was the 2020AS RFP overseen by independent evaluators?

A. Yes. Consistent with Utah and Oregon Commissions' requirements, the solicitation process was overseen by two independent evaluators—one retained by PacifiCorp and appointed by the Oregon Commission (PA Consulting Group, Inc.), and one retained by the Utah Commission (Merrimack Energy Group).

Q. What were the independent evaluators' conclusions regarding the 2020AS RFP?

A. Both independent evaluators concluded that the process was fair and transparent, and that the bids selected for the final shortlist were reasonable.

Q. Please describe the Utah independent evaluator's conclusions regarding the 2020AS RFP.

A. In its Shortlist Report, the Utah independent evaluator concluded that the RFP was fair, reasonable, and in the public interest.[12] In particular, the Utah independent evaluator concluded:

- The market response to the RFP was robust and, "Based on the unbelievable response from the market it is safe to say that the solicitation process resulted in a very competitive process with many more proposals generally submitted than the expected requirements by bubble identified by PacifiCorp."[13]

[12] *In re Rocky Mountain Power 2020AS RFP Application,* Docket No. 20-035-05 (Utah Public Service Commission; Sept. 2, 2021) (https://psc.utah.gov/2020/01/24/docket-no-20-035-05/).
[13] Utah Independent Evaluator Shortlist Report at 74.

- PacifiCorp engaged the bidders throughout the process in a timely manner to ensure that all bidders were treated fairly.
- All bidders were treated the same, had access to the same information at the same time, and had an equal opportunity to compete.
- PacifiCorp implemented its evaluation and selection process consistent with its proposed evaluation and selection process as outlined in the RFP in a structured and consistent manner designed to result in the selection of a portfolio of projects that would result in a least cost solution.
- PacifiCorp subjected all bidders to the same information requirements and conducted a consistent evaluation process with all proposals treated equally in terms of the evaluation methodology and information required of each bidder.
- The selection process was unbiased with respect to ownership structures, i.e., the process did not unreasonably favor bids that resulted in a utility-owned resource.
- The selected bids resulted in lower system cost than a case where no bids were selected and maximized customer benefits while managing risk.

Q. Please describe the Oregon independent evaluator's conclusions regarding the 2020AS RFP.

A. In its Closing Report, the Oregon independent evaluator concluded that the final shortlist reflected a diverse portfolio of competitive resources that achieves the resource adequacy and least cost goals set forth in PacifiCorp's IRP.[14] This was based on the following conclusions:

- PacifiCorp's procurement process, scoring methodology and results were fair and free of bias across all bids and bidders.
- PacifiCorp applied the rules of the 2020AS RFP in an unbiased manner, communicated transparently with the independent evaluators regarding their modelling processes and with stakeholders regarding their decisions.
- PacifiCorp's bid price scores were on average consistent with the independent evaluator's independent scoring methodology.

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[14] *In re PacifiCorp's 2020AS RFP Application,* Docket No. UM 2059 (Oregon Commission; Jun. 15, 2021) (https://apps.puc.state.or.us/edockets/DocketNoLayout.asp?DocketID=22320).

- PacifiCorp's utilization of an outside consultant, WSP Global, to evaluate wind, solar, and battery storage benefitted stakeholders.

- The final shortlist was reasonably aligned with the 2019 IRP preferred portfolio.

Q. Did the Oregon Commission acknowledge the shortlist?

A. Yes.[15] Acknowledgement means that the Oregon Commission found that the "final shortlist appears reasonable at the time of acknowledgment and was determined in a manner consistent with [Oregon's] competitive bidding rules."[16] The Oregon Commission noted that the final shortlist "is a reasonable capacity and energy blend, with diversity in contract structures (and therefore rate impact profiles), technology types, and geography."[17]

C. <u>Price-Policy Assumptions</u>

Q. Please summarize the natural gas and CO_2 price assumptions used in the economic analysis.

A. The economic analysis of the Transmission Projects includes five price-policy scenarios—MM, MN, HH, LN, and SCGHG. 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 the Transmission Projects. 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 2

[15] Docket No. UM 2059, Order No. 21-437 (Nov. 24, 2021) (https://apps.puc.state.or.us/orders/2021ords/21-437.pdf).
[16] *Id.* at 12.
[17] *Id.* at 13.

summarizes the price-policy scenarios used to analyze the Transmission Projects.

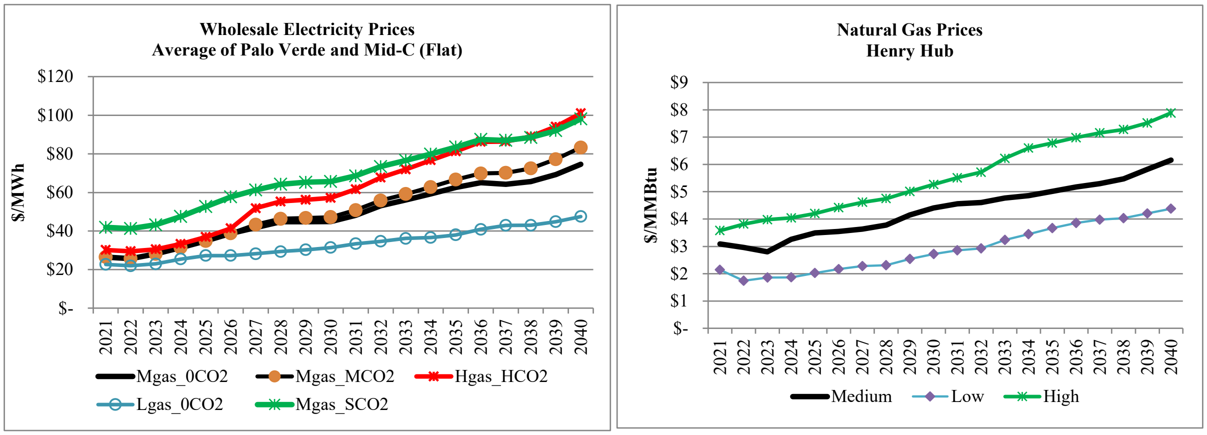
Table 2. Price-Policy Scenario Assumption Overview

Price-Policy Scenario	Henry Hub Natural Gas Price (Levelized $/MMBtu)	CO_2 Price Description
MM	$4.44	$9.93/ton starting 2025 rising to $57.94/ton in 2040
MN	$4.44	None
HH	$5.64	$22.57/ton starting 2025 rising to $102.48/ton in 2040
LN	$2.94	None
SCGHG	$4.44	$74.10/ton starting 2021 rising to $150.38/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 March 31, 2021, which was the most current OFPC available when PacifiCorp prepared its modeling inputs for the 2021 IRP. The first 36 months of the OFPC reflect market forwards at the close of a given trading day (March 31, 2021, in this case). As such, these 36 months are market forwards as of March 2021. 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, multi-client "off-the-shelf" price forecast. The fundamentals portion of the electricity OFPC reflects prices as forecast by AURORAXMP4 (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.

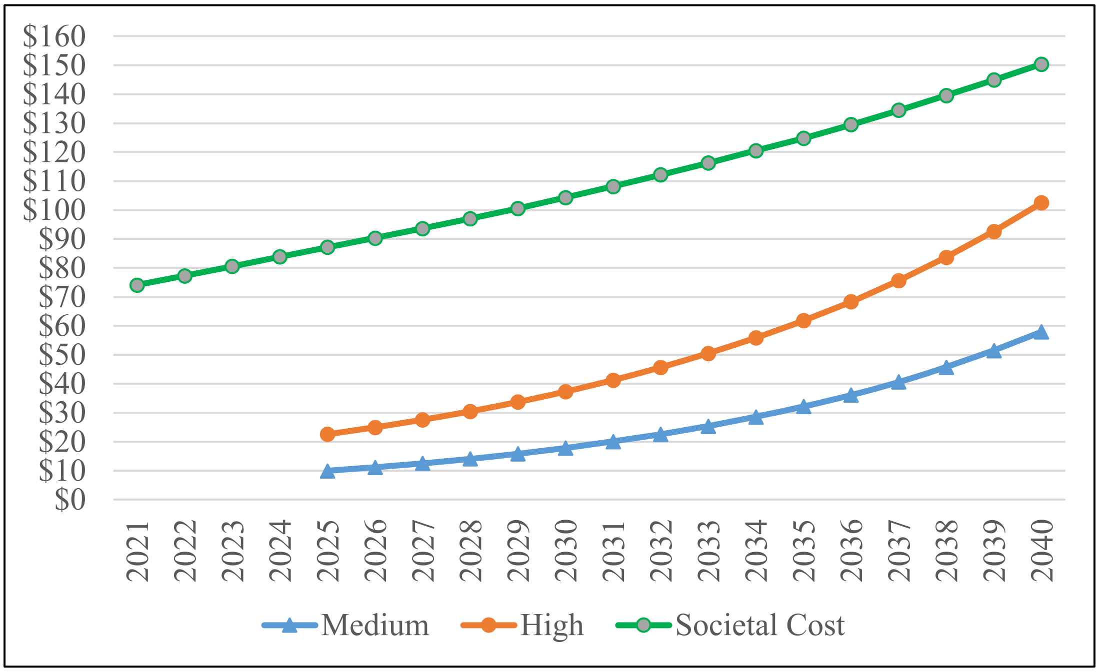
Figure 1. Natural Gas Price Assumptions



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

A. PacifiCorp used four different CO_2 price scenarios in the 2021 IRP—zero, medium, high, and a price forecast that aligns with the social cost of greenhouse gases. The medium and high scenario are derived from expert third-party, multi-client "off-the-shelf" subscription services. Both scenarios apply a CO_2 price beginning 2025. PacifiCorp also incorporated the social cost of greenhouse gas, which is assumed to start in 2021. The social cost of greenhouse gases is applied such that the price for the social cost of greenhouse gas is reflected in market prices and dispatch costs for the purposes of developing each portfolio (*i.e.,* incorporated into capacity expansion optimization modeling). Figure 2 shows the three non-zero CO_2 price assumptions used to analyze the Transmission Projects.

Figure 2. CO_2 Price Assumptions



Q. How did PacifiCorp pair the natural gas and CO_2 price assumptions for purposes of its analysis of the Transmission Projects?

A. Scenarios pairing medium gas prices with alternative CO_2 price assumptions reflect OFPC forwards through April 2024 before transitioning to a fundamentals forecast. Scenarios using high or low gas prices, regardless of CO_2 price assumptions, do not incorporate any market forwards because these scenarios are designed to reflect an alternative view to that of the market. As such, the low and high natural gas price scenarios are purely fundamental forecasts. Low and high natural gas price scenarios are also derived from expert third-party, multi-client "off-the-shelf" subscription services.

Q. Does including 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 the Transmission Projects. When determining CO_2 costs used for planning purposes, the Company strives to ensure that it is not an outlier as discussed above, and the medium price is within a reasonable range used by the industry to assess risk and conduct prudent resource planning.

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 zero-emission resources or customer preferences.

D. <u>Modeling Methodology</u>

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

A. PacifiCorp calculated a system present-value revenue requirement (PVRR) by identifying least-cost resource portfolios and dispatching system resources through 2040, which aligns with the 20-year forecast period used in the 2021 IRP. Net customer benefits are calculated as the PVRR(d) between two simulations of PacifiCorp's system. One simulation includes the Transmission Projects, and the other simulation excludes them. In addition, because wind bids selected from the 2020AS RFP located in eastern Wyoming cannot interconnect without the Transmission Projects, these wind resources are also eliminated from the simulation without the Transmission Projects. When the two simulations are compared, changes to system costs are attributable to the Transmission Projects and associated wind resources from the 2020AS RFP final shortlist.

Customers are expected to realize benefits when the system PVRR from the simulation with the Transmission Projects is lower than the system PVRR without the Transmission Projects. Conversely, customers would experience increased costs if the system PVRR with the Transmission Projects were higher than the system PVRR without the Transmission Projects.

Q. Are there any other costs that differ between the simulations with and without the Transmission Projects?

A. Yes. The simulation that excludes the Transmission Projects includes the cost of transmission upgrades necessary to accommodate PacifiCorp's obligation to provide 500 MW of firm PTP transmission service to a third-party customer. As explained in more detail by Company witness Vail, these transmission upgrade costs were included because, even conservatively ignoring all the executed interconnection service and transmission service contracts listing the Transmission Projects as prerequisites and focusing solely on the upgrades required to provide service under one transmission service contract, PacifiCorp assumed it would need to construct a 230-kV line by the end of 2024 at an estimated cost of approximately $1.4 billion.

Further, this $1.4 billion cost is the minimum cost for the alternative considering that it includes only the upgrades required to provide service under a single transmission service contract. Additional costs would be incurred to provide service under all interconnection service contracts listing the Transmission Projects as prerequisites. To provide service under all these contracts, it is likely the alternative would be to construct the Transmission Projects, which means that construction of these transmission investments are unavoidable given PacifiCorp's federal open access transmission tariff obligations to grant interconnection and transmission service requests.

Q. Please describe the modeling tool used to create the economic analysis of the Transmission Projects.

A. PacifiCorp uses the PLEXOS modeling system. The PLEXOS modeling system 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 improved 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 unique resource portfolios across a range of different planning cases. Informed by the public-input process, PacifiCorp identified case assumptions that were used to produce optimized resource portfolios, each one unique regarding the type, timing, location, and amount of new resources that could be pursued to serve customers over the next 20 years. Portfolios from the LT model are 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.

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 among five price-policy scenarios (MM, MN, HH, LN, and SCGHG). 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 to 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, resource portfolios (with and without the Transmission Projects and associated wind resources) were 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 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 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 the Transmission Projects?

A. Yes. The PLEXOS model is the appropriate modeling tool when evaluating significant capital investments that influence PacifiCorp's resource mix and affect least-cost dispatch of system resources. The LT model simultaneously and endogenously evaluates capacity and energy trade-offs associated with resource and transmission capital projects and is needed to understand how the type, timing, and location of future resources might be affected by the Transmission Projects. The ST and MT models provide additional granularity on how the Transmission Projects are projected to affect system operations while assessing stochastic risks. Together, the LT, MT, and ST models are best suited to perform a benefit analysis for the Transmission Projects 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 each portfolio 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 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 Transmission Projects?

A. Yes. The economic analysis also included one sensitivity that quantified how changes in new resource capital costs for the two BTA wind projects and capital cost assumptions for the Transmission Projects influenced projected customer benefits.

Q. Company witness Vail's testimony indicates that the Transmission Projects will enable up to 2,030 MW of new resources to interconnect in eastern Wyoming. Why does your analysis only account for 1,640 MW?

A. The economic analysis reasonably accounted for only those wind resources that were selected to the 2020AS RFP final shortlist.

Q. Does PacifiCorp assume that all the up-front capital costs of the Transmission Projects will be paid by its retail customers?

A. No. The cost of the Transmission Projects will be shared between PacifiCorp's retail and wholesale transmission customers. In my analyses, I assumed retail customers would pay 80 percent of the revenue requirement from the up-front capital cost for the Transmission Projects, after accounting for an assumed 20 percent revenue credit from the Company's transmission customers.

E. <u>Price-Policy Scenario Results</u>

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

A. Table 3 summarizes the PVRR(d) results for each price-policy scenario.[18]

Table 3. PVRR(d) (Benefit)/Cost of the Transmission Projects ($ million)

Price-Policy Scenario	PVRR(d)	Risk-Adjusted PVRR(d)
MM	($128)	($260)
LN	$755	$670
MN	$393	$289
HH	($932)	($1,100)
SCGHG	($2,568)	($2,819)

[18] Exhibit PAC/801 Transmission Projects Analysis.

As shown above, system costs increase when the Transmission Projects are removed from the portfolio in the MM, HH, and SCGHG price-policy scenarios. Conversely, costs decrease in the LN and MN price-policy scenarios. Without the Transmission Projects, emissions from PacifiCorp's generation resources increase considerably—ranging from 8.4 percent in the MN price-policy scenario to 17.8 percent in the SCGHG price-policy scenario. The LN and MN scenarios unrealistically fail to account for the risk that there will be some form of policy action taken to impute a cost or penalty on greenhouse gas emissions over the planning period. It is also unlikely gas prices will be suppressed for many decades to come, as assumed in the LN price-policy scenario. Further, cost-and-risk results indicate that there is a tremendous opportunity cost of not building the Transmission Projects should policies develop that impose costs on greenhouse gas emissions. This is seen with the disproportionate increase in costs under the HH and SCGHG price-policy scenarios relative to the size of cost reductions in the unlikely LN and MN price-policy scenarios.

Considering that the removal of the Transmission Projects increases system costs among the MM, HH, and SCGHG price-policy scenarios, significantly increases emissions and associated costs and risks, and significantly increases market-reliance risk (discussed further below), this analysis supports the necessity of the Transmission Projects and indicates that they are likely to result in robust customer benefits.

Q. Did you calculate how the PVRR(d) results presented above would change if you assumed the Transmission Projects would be required to provide service under all these interconnection and transmission service contracts?

A. Yes. This would increase the cost of the "alternative" to equal the cost of the Transmission Projects, which represents a $971 million increase in unavoidable capital relative to what is shown in the table above. This translates into $482 million on a PVRR basis. Table 4 shows the PVRR(d) results with this level of unavoidable capital. When this higher cost is applied to the results, the MN price-policy scenario now shows there are significant customer benefits from the Transmission Projects.

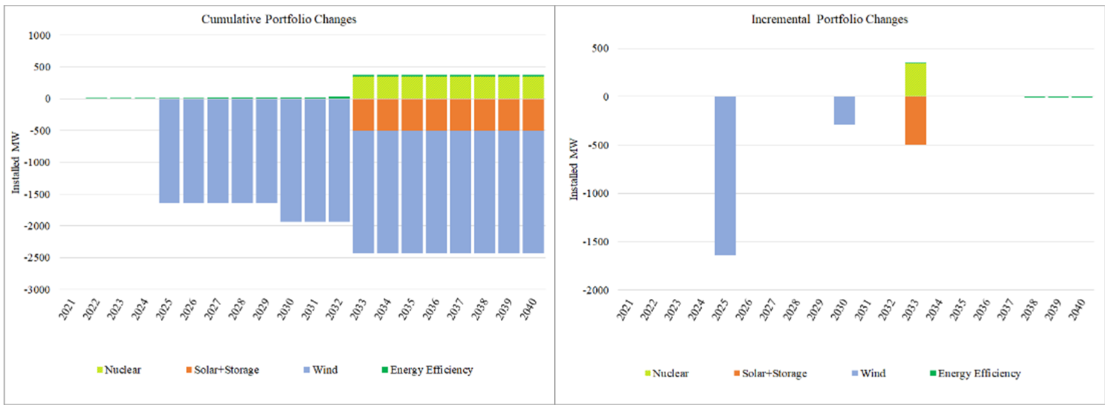
Table 4. PVRR(d) (Benefit)/Cost of the Transmission Projects Assuming the Transmission Projects are Unavoidable ($ million)

Price-Policy Scenario	PVRR(d)	Risk-Adjusted PVRR(d)
MM	($610)	($742)
LN	$273	$188
MN	($90)	($194)
HH	($1,414)	($1,582)
SCGHG	($3,050)	($3,301)

Q. Please describe the impact of removing the Transmission Projects and associated wind resources from the 2021 IRP's preferred portfolio.

A. Figure 3 shows the cumulative (at left) and incremental (at right) portfolio changes when the Transmission Projects are eliminated under the MM price-policy scenario. A positive value indicates an increase in resources and a negative value indicates a decrease in resources when the Transmission Projects are eliminated. Without the Transmission Projects, the 1,640 MW of wind resources selected in the 2020AS RFP are removed from the portfolio in 2024 (shown as a reduction in 2025, the first full year these resources would be online). An additional 289 MW of wind is eliminated in 2030. In 2034, the absence of the new wind resources triggers the addition of an advanced nuclear plant that displaces solar co-located with storage resources.

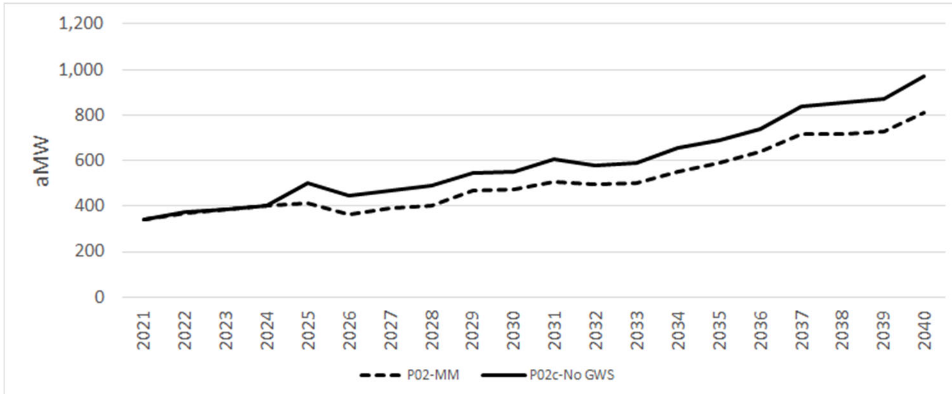
Figure 3. Changes in the Resource Portfolio without the Transmission Projects



Q. Does the removal of the Transmission Projects and associated wind resources increase the Company's reliance on market purchases?

A. Yes. Figure 4 shows how market purchases change when the Transmission Projects are removed from the portfolio under the MM price-policy scenario. With fewer resources, market purchases increase by nearly 20 percent on an annual basis. This creates higher risk as the Company is forced to rely on market purchases at a time when there are increasing resource adequacy concerns throughout the western interconnect. This increased market and reliability risk is not reflected in the PVRR(d) results.

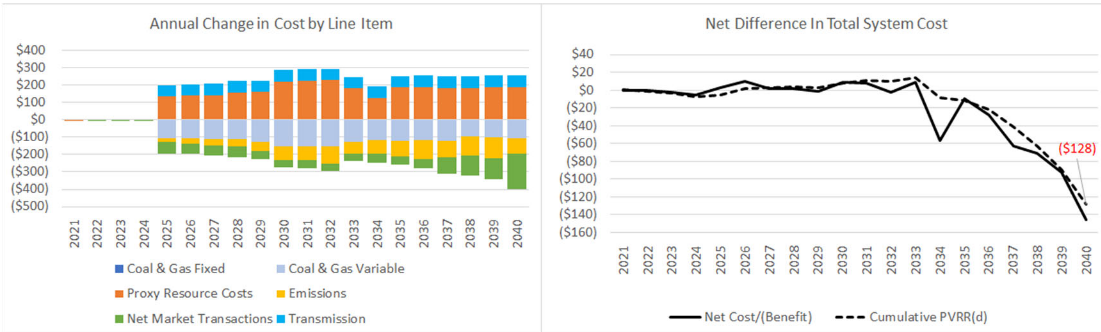
Figure 4. Changes in Market Purchases without the Transmission Projects



Q. How do system costs change with and without the Transmission Projects?

A. Figure 5 summarizes changes in system costs (conservatively assuming the cost for a 230-kV alternative is unavoidable), based on ST model results using MM price-policy assumptions, when the Transmission Projects are eliminated from the portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2040, the PVRR(d) shows that the portfolio without the Transmission Projects is $128 million higher cost than the portfolio with the Transmission Projects. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio without the Transmission Projects is $260 million higher cost than the portfolio with the Transmission Projects. The risk-adjusted results indicate that the Transmission Projects add significant risk mitigation benefits associated with volatility in market prices, loads, hydro generation, and unplanned outages.

Figure 5. Increase/(Decrease) in System Costs when the Transmission Projects are Removed from the Portfolio



Q. Is there incremental customer upside to the PVRR(d) results?

A. Yes. The PVRR(d) results presented in Table 4 do not reflect the potential value of RECs generated by the incremental energy output from the renewable projects enabled by the Transmission Projects. Customer benefits for all price-policy scenarios would improve by approximately $42 million for every dollar assigned to the incremental RECs that will be generated through 2040. Beyond potential REC-revenue benefits, the economic analysis of the Transmission Projects does not reflect the reliability benefits that these investments will provide to the transmission system, which are described by Company witness Vail.

Q. How do the risk-adjusted PVRR(d) results compare to the stochastic-mean PVRR(d) results?

A. The risk-adjusted PVRR(d) results show an increase in the benefits of the Transmission Projects when compared to the reported ST-model PVRR(d) results. This indicates that the Transmission Projects provide stochastic risk benefits by making the system less susceptible to low-probability combinations of load, market price, hydro generation, and thermal outage volatility that can increase system costs.

Q. Have you calculated how changes in the capital cost for the Transmission Projects might affect customer benefits?

A. Yes. A one percent increase in the initial capital costs associated with the Transmission Projects would reduce PVRR benefits by $4.8 million. This estimate conservatively assumes that there is no change in transmission costs that will be avoided with the construction of the Transmission Projects. In the MM price-policy scenario, capital costs for the Transmission Projects would need to increase by 54 percent to eliminate customer benefits on a risk-adjusted basis. This demonstrates that the projected customer benefits are robust to potential variations in capital costs for the Transmission Projects, particularly when considering that the cost estimates used in the economic analysis of the Transmission Projects reflect PacifiCorp's experience with the recent construction of Gateway West Segment D.2 and the associated 230-kV network upgrades reflecting current market conditions.

F. Post-Construction Economic Review

Q. Did you continue to revisit your economic analysis of the Transmission Projects after initiating construction?

A. Yes.

Q. Why did you continue to revisit your economic analysis?

A. After PacifiCorp provided its notice to proceed to begin constructing the Transmission Projects, the Company continued to negotiate contracts for the wind resources that are dependent on the Transmission Projects. During the pendency of those negotiations, there were two significant developments that affected the cost of the wind resources. Considering that the cost of the wind resources affects the economic analysis of the Transmission Projects, I continued to check that changes to costs did not erode customer benefits.

Q. Please describe the two developments that affected the cost of the wind resources dependent upon the Transmission Projects.

A. First, as the Company finalized contracts with resources selected to the 2020AS RFP final shortlist, national tariff policies, global supply-chain challenges, and inflationary pressures required that bidders secure higher prices than originally offered into the 2020AS RFP. Second, Congress passed the IRA that, among other things, provided an opportunity for the wind projects dependent upon the Transmission Projects to qualify for a 110 percent PTC, which is substantially higher than the 60 percent PTC assumed in my economic analysis that supported the Company's decision to begin constructing the Transmission Projects.

Q. How did you evaluate the impact of these developments on the economic analysis of the Transmission Projects?

A. As the Company finalized the wind resource contracts to capture price changes and new provisions related to the IRA, MM price-policy results were revisited so that we could understand how the economic analysis was being impacted. The updated analysis captured price changes in the contracts and incorporated updated energy values for projected wind energy using more current market price assumptions (*i.e.,* June 2022).

Q. Did your post-construction economic review capture other updates?

A. Yes. Due to the price pressures I discussed above, some of the 2020AS RFP final shortlist bidders were unwilling to offer any form of price update. These projects were removed from consideration. While this did not include any of the wind projects dependent on the Transmission Projects, the removal of bids increases the overall need for new resources. The updated analysis also included any new contracts that were executed outside of the 2020AS RFP process and incorporated the most current load forecast, which was developed in May 2022. The updated analysis also accounted for the potential impact of the OTR.

Q. What did you find when you prepared this post-construction economic review of the Transmission Projects?

A. This on-going review continued to show that the Transmission Projects are expected to generate customer benefits. The last of these reviews, prepared in September 2022, reflected updated pricing for all wind resource PPAs dependent upon the Transmission Projects and showed risk-adjusted customer benefits totaling $247 million in the MM price-policy scenario. This is similar to the comparable risk-adjusted customer benefits totaling $260 million from the economic analysis in place when the Company initiated construction of the Transmission Projects.

IV. CONCLUSION

Q. Please summarize the conclusions of your Gateway South and Gateway West testimony.

A. PacifiCorp's analysis shows that the Transmission Projects are necessary and in the public interest. Under the MM price-policy scenario, the Transmission Projects produce significantly lower total system costs—ranging from $128 to $260 million when using the most conservating assumptions for avoided transmission and ranging from $610 million to $742 million when assuming the Transmission Projects are unavoidable. The Transmission Projects are also lower risk than alternative scenarios without the resources. Most notably, without the Transmission Projects and accompanying wind resources, the Company is forced to rely heavily on market purchases to serve load, which increases risk related to market volatility and creates reliability concerns given the region's well established resource adequacy concerns. By proactively constructing the Transmission Projects the Company can not only save customers money (as evidenced by the savings in the MM price-policy scenario) but also reduce customer risk, which is a non-quantifiable benefit that strongly favors the Transmission Projects. The updated economic analysis of the Transmission Projects demonstrates that net benefits more than outweigh net project costs.

Q. What do you recommend?

A. As supported by PacifiCorp's economic analysis, I recommend that the Commission determine that Company's decisions to invest in the Transmission Projects are prudent and reasonable.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 433
Exhibit PAC/801
Witness: Rick T. Link

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Rick T. Link

Transmission Projects Analysis

February 2024

Estimated Annual Revenue Requirement Results ($ million)

Medium Gas, Medium CO2

(Benefit) /Cost	*PVRR(d)*	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Cost of Project	$1,837	$0	$0	$0	$0	$193	$194	$199	$214	$217	$225	$231	$234	$240	$238	$298	$301	$298	$300	$304	$309
New Wind Capital Cost	$397	$0	$0	$0	$0	$33	$34	$34	$40	$40	$42	$45	$45	$47	$51	$93	$94	$94	$95	$97	$99
Wind Run-Rate Fixed Costs	$327	$0	$0	$0	$0	$51	$51	$54	$53	$55	$56	$57	$59	$59	$56	$16	$17	$17	$17	$17	$17
PPA	$1,332	$0	$0	$0	($0)	$180	$181	$188	$197	$202	$208	$215	$220	$224	$220	$130	$132	$129	$129	$132	$134
PTC Credits	($748)	$0	$0	$0	$0	($130)	($130)	($135)	($134)	($139)	($140)	($143)	($148)	($148)	($148)	$0	$0	$0	$0	$0	$0
Wind Tax	$14	$0	$0	$0	$0	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2
Transmission GWS	$1,261	$0	$0	$0	$0	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138
Transmission D.1	$185	$0	$0	$0	$0	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20
Avoided Transmission - Base 230 kV	($843)	$0	$0	$0	$0	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)
Transmisison Network Wind	$41	$0	$0	$0	$0	$5	$5	$5	$5	$4	$4	$4	$4	$4	$4	$5	$4	$4	$4	$4	$4
Transmission OATT Credit	($129)	$0	$0	$0	($0)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)
Change in NPC	($1,345)	($0)	$0	($1)	($2)	($170)	($158)	($166)	($175)	($175)	($189)	($198)	($193)	($163)	($169)	($171)	($171)	($212)	($211)	($222)	($306)
Change in Emissions	($488)	$0	$0	$0	$0	($25)	($32)	($36)	($41)	($49)	($82)	($80)	($99)	($71)	($76)	($87)	($107)	($95)	($105)	($120)	($91)
Change in VOM & Driver Adjustments	($40)	($0)	$0	$0	($0)	($5)	($5)	($5)	($3)	($3)	($3)	($3)	($3)	$34	($16)	($16)	($16)	($16)	($16)	($16)	($17)
Change in DSM	($41)	$0	($1)	($2)	($3)	($3)	($3)	($4)	($5)	($5)	($5)	($5)	($6)	($5)	($5)	($5)	($6)	($6)	($6)	($6)	($6)
Change in Deficiency	($4)	($0)	$0	$0	($1)	($3)	$0	($1)	($2)	($0)	$0	$0	$0	$0	$0	$0	$1	($0)	$0	$0	$0
Change in System Fixed Cost	($48)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	$48	$49	$49	($40)	($41)	($42)	($43)	($45)	($46)	($48)	($49)
Net (Benefit) /Cost	($128)	($0)	($1)	($2)	($6)	($12)	($4)	($12)	($12)	($16)	($5)	($6)	($17)	($5)	($70)	($24)	($42)	($76)	($85)	($107)	($160)
Risk Adjustment	($132)																				
Net (Benefit) /Cost with Risk Adjustment	($260)																				

Medium Gas, No CO2

(Benefit) /Cost	*PVRR(d)*	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Cost of Project	$1,811	$0	$0	$0	$0	$194	$195	$201	$215	$217	$225	$231	$234	$240	$167	$297	$301	$298	$300	$304	$309
New Wind Capital Cost	$398	$0	$0	$0	$0	$34	$35	$34	$40	$40	$42	$45	$45	$47	$51	$93	$94	$94	$95	$97	$99
Wind Run-Rate Fixed Costs	$326	$0	$0	$0	$0	$50	$50	$54	$52	$55	$56	$57	$59	$59	$56	$16	$17	$17	$17	$17	$17
PPA	$1,304	$0	$0	$0	($0)	$180	$181	$188	$197	$202	$208	$215	$220	$224	$149	$130	$132	$129	$129	$132	$134
PTC Credits	($746)	$0	$0	$0	$0	($129)	($129)	($134)	($134)	($139)	($140)	($143)	($148)	($148)	($148)	$0	$0	$0	$0	$0	$0
Wind Tax	$14	$0	$0	$0	$0	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2
Transmission GWS	$1,261	$0	$0	$0	$0	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138
Transmission D.1	$185	$0	$0	$0	$0	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20
Avoided Transmission - Base 230 kV	($843)	$0	$0	$0	$0	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)
Transmisison Network Wind [1]	$41	$0	$0	$0	$0	$5	$5	$5	$5	$4	$4	$4	$4	$4	$4	$5	$4	$4	$4	$4	$4
Transmission OATT Credit	($129)	$0	$0	$0	($0)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)
Change in NPC	($1,305)	$1	$0	($1)	($1)	($163)	($163)	($168)	($171)	($172)	($202)	($197)	($203)	($150)	($152)	($153)	($167)	($190)	($202)	($215)	($251)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in VOM & Driver Adjustments	($49)	($0)	($0)	$0	($0)	($7)	($8)	($8)	($4)	($4)	($4)	($4)	($4)	$34	($16)	($17)	($17)	($17)	($17)	($17)	($16)
Change in DSM	($41)	$0	($1)	($2)	($3)	($3)	($3)	($4)	($5)	($5)	($5)	($5)	($6)	($5)	($5)	($5)	($6)	($6)	($6)	($6)	($6)
Change in Deficiency	($4)	($0)	$0	$0	($1)	($3)	($0)	($1)	($1)	$0	($0)	$0	$0	($0)	$0	$0	($1)	$0	$0	$0	$0
Change in System Fixed Cost	($20)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	$48	$49	$49	($40)	$30	($42)	($43)	($45)	($46)	($48)	($49)
Net (Benefit) /Cost	$393	$0	($1)	($2)	($5)	$18	$21	$19	$33	$36	$62	$74	$70	$80	$23	$80	$68	$39	$28	$20	($12)
Risk Adjustment	($104)																				
Net (Benefit) /Cost with Risk Adjustment	$289																				

Estimated Annual Revenue Requirement Results ($ million)

High Gas, High CO2

(Benefit) /Cost	*PVRR(d)*	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Cost of Project	$1,808	$0	$0	$0	$0	$193	$194	$199	$214	$217	$225	$231	$234	$240	$167	$298	$301	$298	$300	$304	$309
New Wind Capital Cost	$396	$0	$0	$0	$0	$33	$34	$34	$40	$40	$42	$45	$45	$47	$51	$93	$94	$94	$95	$97	$99
Wind Run-Rate Fixed Costs	$327	$0	$0	$0	$0	$51	$51	$54	$53	$55	$56	$57	$59	$59	$56	$16	$17	$17	$17	$17	$17
PPA	$1,304	$0	$0	$0	($0)	$180	$181	$188	$197	$202	$208	$215	$220	$224	$149	$130	$132	$129	$129	$132	$134
PTC Credits	($749)	$0	$0	$0	$0	($131)	($131)	($135)	($134)	($139)	($140)	($143)	($148)	($148)	($148)	$0	$0	$0	$0	$0	$0
Wind Tax	$14	$0	$0	$0	$0	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2
Transmission GWS	$1,261	$0	$0	$0	$0	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138
Transmission D.1	$185	$0	$0	$0	$0	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20
Avoided Transmission - Base 230 kV	($843)	$0	$0	$0	$0	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)
Transmisison Network Wind	$41	$0	$0	$0	$0	$5	$5	$5	$5	$4	$4	$4	$4	$4	$4	$5	$4	$4	$4	$4	$4
Transmission OATT Credit	($129)	$0	$0	$0	($0)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)
Change in NPC	($1,697)	$0	$1	$1	($4)	($185)	($183)	($199)	($217)	($206)	($232)	($241)	($259)	($217)	($211)	($237)	($233)	($269)	($346)	($349)	($339)

Change in Emissions	($936)	$0	$0	$0	$0	($71)	($79)	($86)	($84)	($109)	($160)	($161)	($169)	($125)	($153)	($150)	($186)	($188)	($130)	($170)	($203)
Change in VOM & Driver Adjustments	($37)	($0)	$0	$0	$0	($3)	($3)	($3)	($3)	($3)	($2)	($2)	($3)	$34	($16)	($16)	($16)	($17)	($17)	($19)	($18)
Change in DSM	($41)	$0	($1)	($2)	($3)	($3)	($3)	($4)	($5)	($5)	($5)	($5)	($6)	($5)	($5)	($5)	($6)	($6)	($6)	($6)	($6)
Change in Deficiency	($8)	($3)	$0	$0	($1)	($3)	$0	($1)	($3)	$0	($0)	($0)	($2)	($0)	($0)	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($20)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	$48	$49	$49	($40)	$30	($42)	($43)	($45)	($46)	($48)	($49)
Net (Benefit) /Cost	($932)	($3)	($1)	($1)	($8)	($72)	($75)	($95)	($98)	($106)	($125)	($130)	($154)	($113)	($189)	($154)	($183)	($227)	($246)	($287)	($306)
Risk Adjustment	($168)																				
Net (Benefit) /Cost with Risk Adjustment	($1,100)																				

Low Gas, No CO2

(Benefit) /Cost	*PVRR(d)*	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Cost of Project	$1,838	$0	$0	$0	$0	$194	$195	$200	$214	$217	$225	$231	$234	$240	$238	$298	$301	$298	$300	$304	$309
New Wind Capital Cost	$397	$0	$0	$0	$0	$34	$34	$34	$40	$40	$42	$45	$45	$47	$51	$93	$94	$94	$95	$97	$99
Wind Run-Rate Fixed Costs	$326	$0	$0	$0	$0	$51	$51	$54	$53	$55	$56	$57	$59	$59	$56	$16	$17	$17	$17	$17	$17
PPA	$1,332	$0	$0	$0	($0)	$180	$181	$188	$197	$202	$208	$215	$220	$224	$220	$130	$132	$129	$129	$132	$134
PTC Credits	($748)	$0	$0	$0	$0	($130)	($130)	($134)	($134)	($139)	($140)	($143)	($148)	($148)	($148)	$0	$0	$0	$0	$0	$0
Wind Tax	$14	$0	$0	$0	$0	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2
Transmission GWS	$1,261	$0	$0	$0	$0	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138
Transmission D.1	$185	$0	$0	$0	$0	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20
Avoided Transmission - Base 230 kV	($843)	$0	$0	$0	$0	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)
Transmisison Network Wind [1]	$41	$0	$0	$0	$0	$5	$5	$5	$5	$4	$4	$4	$4	$4	$4	$5	$4	$4	$4	$4	$4
Transmission OATT Credit	($128.78)	$0.00	$0.00	$0.00	($0.07)	($14.19)	($14.17)	($14.14)	($14.13)	($14.11)	($14.10)	($14.08)	($14.06)	($14.05)	($14.04)	($14.14)	($14.12)	($14.10)	($14.08)	($14.07)	($14.06)
Change in NPC	($948)	($0)	$0	$0	($2)	($105)	($109)	($115)	($120)	($119)	($141)	($141)	($147)	($118)	($123)	($122)	($130)	($151)	($159)	($165)	($200)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in VOM & Driver Adjustments	($40)	$0	$0	$0	$0	($4)	($5)	($6)	($3)	($2)	($2)	($3)	($3)	$34	($17)	($17)	($17)	($17)	($17)	($17)	($17)
Change in DSM	($41)	$0	($1)	($2)	($3)	($3)	($3)	($4)	($5)	($5)	($5)	($5)	($6)	($5)	($5)	($5)	($6)	($6)	($6)	($6)	($6)
Change in Deficiency	($5)	($0)	$0	$0	($2)	($3)	($0)	($1)	($2)	($0)	($0)	$0	$0	($0)	$0	($0)	($0)	$0	$0	$0	$0
Change in System Fixed Cost	($48)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	$48	$49	$49	($40)	($41)	($42)	($43)	($45)	($46)	($48)	($49)
Net (Benefit) /Cost	$755	($0)	($1)	($2)	($6)	$79	$77	$74	$84	$90	$125	$132	$128	$111	$52	$111	$105	$79	$72	$69	$38
Risk Adjustment	($85)																				
Net (Benefit) /Cost with Risk Adjustment	$670																				

SC-GHG

(Benefit) /Cost	*PVRR(d)*	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Cost of Project	$1,836	$0	$0	$0	$0	$192	$194	$199	$214	$217	$225	$231	$234	$240	$238	$298	$301	$298	$300	$304	$309
New Wind Capital Cost	$396	$0	$0	$0	$0	$33	$34	$34	$40	$40	$42	$45	$45	$47	$51	$93	$94	$94	$95	$97	$99
Wind Run-Rate Fixed Costs	$328	$0	$0	$0	$0	$51	$52	$54	$53	$55	$56	$57	$59	$59	$56	$16	$17	$17	$17	$17	$17
PPA	$1,332	$0	$0	$0	($0)	$180	$181	$188	$197	$202	$208	$215	$220	$224	$220	$130	$132	$129	$129	$132	$134
PTC Credits	($750)	$0	$0	$0	$0	($131)	($131)	($135)	($134)	($139)	($140)	($143)	($148)	($148)	($148)	$0	$0	$0	$0	$0	$0
Wind Tax	$14	$0	$0	$0	$0	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2
Transmission GWS	$1,261	$0	$0	$0	$0	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138
Transmission D.1	$185	$0	$0	$0	$0	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20
Avoided Transmission - Base 230 kV	($843)	$0	$0	$0	$0	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)
Transmisison Network Wind	$41	$0	$0	$0	$0	$5	$5	$5	$5	$4	$4	$4	$4	$4	$4	$5	$4	$4	$4	$4	$4
Transmission OATT Credit	($129)	$0	$0	$0	($0)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)
Change in NPC	($2,129)	$0	($1)	($6)	($4)	($217)	($230)	($243)	($260)	($296)	($363)	($350)	($357)	($286)	($288)	($292)	($304)	($380)	($270)	($291)	($359)
Change in Emissions	($1,919)	($0)	$3	$5	($3)	($317)	($264)	($266)	($245)	($246)	($286)	($286)	($296)	($198)	($218)	($229)	($260)	($257)	($274)	($274)	($260)
Change in VOM	($30)	$0	($0)	$0	$0	($1)	($1)	($2)	($2)	($2)	($1)	($2)	($2)	$35	($16)	($16)	($15)	($22)	($15)	($14)	($17)
Change in DSM	($41)	$0	($1)	($2)	($3)	($3)	($3)	($4)	($5)	($5)	($5)	($5)	($6)	($5)	($5)	($5)	($6)	($6)	($6)	($6)	($6)
Change in Deficiency	($236)	($0)	$0	($15)	($3)	($67)	($38)	($16)	($25)	($4)	($126)	$0	$0	$0	($0)	$0	($1)	($233)	$0	$0	$69
Change in System Fixed Cost	($48)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	$48	$49	$49	($40)	($41)	($42)	($43)	($45)	($46)	($48)	($49)
Net (Benefit) /Cost	($2,568)	($1)	$1	($18)	($13)	($412)	($343)	($331)	($322)	($336)	($508)	($363)	($377)	($254)	($331)	($287)	($328)	($646)	($312)	($328)	($312)
Risk Adjustment	($251)																				
Net (Benefit) /Cost with Risk Adjustment	($2,819)																				