REDACTED
Rocky Mountain Power
Docket No. 17-035-40
Witness: Rick T. Link

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Direct Testimony of Rick T. Link

June 2017

Q. Please state your name, business address, and position with PacifiCorp.

A. My name is Rick T. Link. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My position is Vice President, Resource and Commercial Strategy. I am testifying on behalf of Rocky Mountain Power, a division of PacifiCorp.

Q. Please describe the responsibilities of your current position.

A. I am responsible for PacifiCorp's integrated resource plan ("IRP"), structured commercial business and valuation activities, long-term commodity price forecasts, long-term load forecasts, and environmental strategy and policy activities. Most relevant to this docket, I am responsible for the economic analysis used to screen system resource investments and for conducting competitive request for proposal ("RFP") processes consistent with applicable state procurement rules and guidelines.

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 2016. Over this time period, I 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 was responsible for delivering PacifiCorp's 2013, 2015, and 2017 IRPs; have been directly involved in several resource RFP processes; and performed economic analysis supporting a range of resource 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 Masters 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 Utah Public Service Commission, the Wyoming Public Service Commission, the Public Utility Commission of Oregon, and the Washington Utilities and Transportation Commission.

PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

A. I present and explain the economic analysis that supports PacifiCorp's decision to construct or procure four new Wyoming wind resources with a total capacity of 860 megawatts ("MW") (collectively, the "Wind Projects"), and the decision to construct the "Aeolus-to-Bridger/Anticline Line" and construct the 230 kV Network Upgrades (collectively, the "Transmission Projects").[1] The Transmission Projects

[1] As more specifically described in the testimony of Mr. Rick A. Vail, the Transmission Projects include: (1) a new 140-mile, 500 kV transmission line segment and associated infrastructure running from the new Aeolus substation near Medicine Bow, Wyoming, to the new Anticline substation located near the existing Jim Bridger substation, which includes construction of the new Aeolus and Anticline substations; (2) a new five-mile, 345 kV transmission line that will extend from the proposed Anticline substation to the existing Jim Bridger substation, which includes modifications at the existing Jim Bridger substation to allow termination of the new 345 kV line; (3) installation of a voltage control device at the Latham substation; (4) a new 16-mile, 230 kV transmission line running from the Company's existing Shirley Basin substation to the proposed Aeolus substation, which requires modifications to the Shirley Basin substation and interconnection facilities in the new Aeolus substation to accommodate the new line; (5) reconstruction of four miles of an existing 230 kV transmission line between the proposed Aeolus substation and the Freezeout substation, which requires modifications to the Freezeout substation and interconnection facilities in the new Aeolus substation to accommodate the rebuilt line; and (6) reconstruction of 14 miles of an existing 230 kV transmission line between the Freezeout substation and the Standpipe substation, which requires modifications to the Freezeout and Standpipe substations to accommodate the rebuilt line. Items 1 through 3 are collectively referred to as the "Aeolus-to-Bridger Anticline Line," and items 4 through 6 are collectively referred to as the "230 kV Network Upgrades."

enable interconnection of the new wind resources. My testimony demonstrates that PacifiCorp's proposals to construct or acquire approximately 860 MW of new Wind Projects and construct the Transmission Projects (collectively, the "Combined Projects") is in the public interest. My testimony also summarizes PacifiCorp's assessment of new Wyoming wind resources and the Aeolus-to-Bridger/Anticline Line in its 2017 IRP.

Q. Please summarize your testimony.

A. PacifiCorp's economic analysis supports investments in the Combined Projects. The Wind Projects, which are enabled by the Transmission Projects, will generate federal production tax credits ("PTCs") for ten years; produce zero-fuel-cost energy that will lower net power costs ("NPC"); generate renewable-energy credits ("RECs"), which can be sold in the market to create additional revenues that would lower net customer costs; and help decarbonize PacifiCorp's resource portfolio, which will mitigate long-term risk associated with potential future state and federal policies targeting carbon dioxide ("CO_2") emissions reductions from the electric sector.

The Transmission Projects will relieve congestion on the current transmission system in eastern Wyoming, enable new wind resource interconnections, provide critical voltage support to the Wyoming transmission network, improve overall reliability of the transmission system, enhance PacifiCorp's ability to comply with mandated reliability and performance standards, and reduce line losses. Moreover, the proposed transmission-system investments create an opportunity for further increases to the transfer capability across the Aeolus-to-Bridger/Anticline Line with the construction of additional segments of Energy Gateway.

The Combined Projects will produce customer benefits that significantly outweigh costs. The change in revenue requirement due to the Combined Projects was analyzed using two different modeling tools across nine different scenarios, each with varying natural-gas and CO_2 price assumptions. For each of these scenarios, the present-value revenue requirement differential ("PVRR(d)") was calculated from system revenue requirement forecasts through 2050 (through the 30-year life of the Wind Projects), reflecting nominal capital revenue requirement from the Combined Projects, and from system revenue requirement forecasts over a 20-year period, where capital revenue requirement is levelized.

The Combined Projects show PVRR(d) benefits in seven of the nine scenarios (all scenarios except two using the lowest natural-gas price assumptions) when calculated from system revenue requirement forecasts through 2050. The present-value reduction to the change in system revenue requirement through 2050 is $137 million when assuming medium natural-gas and medium CO_2 price assumptions.

In seven of the nine scenarios (all scenarios except two using the lowest natural-gas price assumptions), the Combined Projects show PVRR(d) benefits when calculated from system revenue requirement forecasts over a 20-year period. Over this 20-year forecast period, the present-value reduction to the change in system revenue requirement due to the Combined Projects ranges between $85 million and $124 million when assuming medium natural-gas and medium CO_2 price assumptions.

The customer benefits from the Combined Projects increase substantially with higher natural-gas price assumptions and higher CO_2 price assumptions. These benefits conservatively do not assign any value to the RECs that will be generated by the Wind

Projects. For every dollar assigned to the incremental RECs that will be generated by the Wind Projects, present-value benefits would improve for all scenarios by an additional $34 million when calculated from the change in system revenue requirement through 2050. When calculated from the change in system revenue requirement over a 20-year period, each dollar assigned to the incremental RECs from the Wind Projects would increase PVRR(d) benefits by $26 million.

Sensitivity analysis shows that substantial benefits of the Combined Projects persist when paired with PacifiCorp's plans to upgrade or "repower" certain wind resources, which is the subject of a concurrently filed application. Sensitivity analysis also shows that there is additional upside to customer benefits if the new equipment is depreciated over a longer life.

2017 INTEGRATED RESOURCE PLAN

Q. Did PacifiCorp analyze new Wyoming wind resources and the Aeolus-to-Bridger/Anticline Line in its 2017 IRP?

A. Yes. The 2017 IRP preferred portfolio, representing PacifiCorp's least-cost, least-risk plan to reliably meet customer demand over a 20-year planning period, includes 1,100 MW of new wind resources located in Wyoming. This wind capacity is enabled by the Aeolus-to-Bridger/Anticline Line, which is also included in the 2017 IRP preferred portfolio. The new wind and Aeolus-to-Bridger/Anticline Line are assumed to be placed in service by the end of 2020 so that the new wind resources can qualify for the full value of PTCs.

Q. What led PacifiCorp to include 1,100 MW of new Wyoming wind resources and the Aeolus-to-Bridger Anticline Line in its 2017 IRP preferred portfolio?

A. All of the resource portfolios produced during the initial stages of the portfolio-development phase of the 2017 IRP contained new Wyoming wind resources in 2021, which for modeling purposes was used as a proxy on-line date for PTC-eligible wind achieving commercial operation by the end of 2020. At the same time, the load-and-resource balance developed for the 2017 IRP shows that PacifiCorp would not require incremental system capacity to meet its 13-percent planning-reserve margin until 2028, accounting for assumed coal unit retirements, incremental energy efficiency savings, and available wholesale-power market purchase opportunities. These results indicated that PTC-eligible wind resources located in wind-rich areas like Wyoming provide customer benefits.

During the initial stages of portfolio development for the 2017 IRP, the amount of Wyoming wind capacity that routinely appeared in 2021 was limited by transmission congestion on PacifiCorp's existing 230 kV transmission system. This congestion affects energy output from resources in eastern Wyoming where there is substantial potential to develop high-quality, low-cost wind resources. Wyoming resource selections at or near the limitation on Wyoming wind capacity caused by transmission constraints indicated clear potential for incremental customer benefits if incremental transmission is added to accommodate more PTC-eligible wind resources located in Wyoming.

To assess these potential incremental benefits, PacifiCorp reviewed components of its Energy Gateway transmission project to identify specific subsegments that could access additional new Wyoming wind resources. In performing this review, PacifiCorp looked at the transmission interconnection queue and determined that sub-segment D2 (the Aeolus-to-Bridger/Anticline Line) of the Energy Gateway transmission project could access a sizable volume of new wind projects being developed in the Aeolus area. PacifiCorp then developed an initial, high-level cost estimate for the Aeolus-to-Bridger/Anticline Line that was used for an initial Aeolus-to-Bridger/Anticline sensitivity assuming 650 MW of incremental transfer capability and 900 MW of new Wyoming wind resources.

Q. Why did PacifiCorp assume new wind resource capacity in excess of the assumed incremental transfer capability of the Aeolus-to-Bridger/Anticline Line in this initial sensitivity?

A. The Aeolus-to-Bridger/Anticline Line can enable new resource interconnections in excess of the transfer capability of the line. PacifiCorp's preliminary sensitivity in the 2017 IRP assumed the Aeolus-to-Bridger/Anticline Line would support at least 900 MW of new resource interconnections. The assumed level of new wind resources is higher than the assumed incremental transfer capability of the transmission line because wind resources do not generate at their full capability in all hours of the year. At times when wind resources in southeastern Wyoming are operating near full output, other resources in the area can be re-dispatched to accommodate PTC-producing wind generation.

Q. What were the results of this initial Aeolus-to-Bridger/Anticline sensitivity?

A. The initial sensitivity indicated that there could be economic benefits from aligning development of the Aeolus-to-Bridger/Anticline Line with new, PTC-eligible

Wyoming wind resources. Based on the promising results from this initial sensitivity, PacifiCorp reviewed its initial, high-level assumptions to determine how refined inputs would affect potential benefits from the incremental new Wyoming wind resources and the Aeolus-to-Bridger/Anticline Line.

PacifiCorp completed power flow and dynamic-stability studies to refine its Aeolus-to-Bridger/Anticline Line assumptions. These studies supported increasing the assumed incremental transfer capability of the new transmission line from 650 MW to 750 MW and suggested that it could enable up to 1,270 MW of new resource interconnections. PacifiCorp also refined its initial, high-level cost assumptions, reducing the estimated capital cost of the project by over $100 million.

In addition, PacifiCorp reviewed its new wind resource cost-and-performance assumptions, initially developed to represent proxy Wyoming wind resources, to focus on specific projects that could be developed in the Aeolus area. Based on this review, PacifiCorp determined that the estimated capital cost for new wind resources could be lowered by 10.7 percent from its initial proxy cost assumptions and that its wind capacity factor assumptions should be reduced from 43 percent to 41.2 percent.

In addition to refining its transmission and new wind resource assumptions, PacifiCorp reviewed whether additional benefits from the wind enabled by the Aeolus-to-Bridger/Anticline Line could be quantified. PacifiCorp identified and quantified three additional value streams associated with its participation in the energy imbalance market ("EIM"), improved transmission reliability, and reduced transmission line losses.

The results from this additional review and analysis were applied in the final

2017 IRP resource-portfolio screening process, where PacifiCorp conducted additional studies that considered analysis performed in earlier resource-portfolio screening stages.

Q. What type of analysis did PacifiCorp consider from earlier resource-portfolio screening stages?

A. In earlier stages of its resource-portfolio screening process, PacifiCorp developed a wind repowering sensitivity, where certain existing wind resources qualify for an additional ten years of PTCs after they are upgraded with modern equipment. The wind repowering project, the subject of a concurrently filed application, showed significant net customer benefits across a range of assumptions related to forward market prices and federal CO_2 policy based on the Clean Power Plan ("CPP"). Considering the significant customer benefits associated with the wind repowering project, PacifiCorp combined its refined assumptions for incremental new Wyoming wind and the Aeolus-to-Bridger/Anticline Line in a study that included wind repowering.

Q. What were the results of PacifiCorp's final 2017 IRP resource-portfolio screening process that incorporated refined and expanded input assumptions for incremental new Wyoming wind resources and the Aeolus-to-Bridger/Anticline Line?

A. Studies developed for the final 2017 IRP resource-portfolio screening process showed significant net customer benefits relative to other resource-portfolio alternatives. Based on these results, the Aeolus-to-Bridger/Anticline Line and the 1,100 MW of new Wyoming wind resources, both assumed to be placed in service by the end of 2020, were included in the 2017 IRP preferred portfolio.

Q. What are the benefits associated with the new Wyoming wind assumed to come online by the end of 2020 that was included in the 2017 IRP preferred portfolio?

A. This new wind, which was included in the 2017 IRP preferred portfolio, will deliver several different benefits for customers. First, these new wind resources will generate PTCs for ten years after being placed in service. The current value of federal PTCs, which is adjusted annually for inflation by the Internal Revenue Service, is $24 per megawatt-hour ("MWh"). At a federal and state effective tax rate of 37.95 percent, the current PTC equates to a $38.68 per MWh reduction in revenue requirement that can be passed through to customers. Second, these zero-fuel-cost assets will provide incremental NPC benefits for customers. Third, the new wind facilities will generate RECs, which can be sold in the market to create additional revenues that would lower net customer costs. Fourth, these zero-emissions assets will help to decarbonize PacifiCorp's resource portfolio and mitigate long-term risk associated with potential future state and federal policies targeting CO_2 emissions reductions from the electric sector.

Q. What are the benefits associated with the Aeolus-to-Bridger/Anticline Line included in the 2017 IRP preferred portfolio?

A. As is the case with the new wind resources, the Aeolus-to-Bridger/Anticline Line will also deliver several benefits for customers. The new line will relieve congestion on the current transmission system in eastern Wyoming and enable the additional wind resource interconnections. As discussed by Mr. Rick A. Vail, the Aeolus-to-Bridger/Anticline Line will also provide critical voltage support to the Wyoming transmission network, improve overall reliability of the transmission system, enhance

PacifiCorp's ability to comply with mandated reliability and performance standards, reduce line losses, and creates an opportunity for further increases to the transfer capability across the Aeolus-to-Bridger/Anticline Line with the construction of additional segments of Energy Gateway.

Q. Did PacifiCorp include an action item for new Wyoming wind resources in its 2017 IRP action plan?

A. Yes. The 2017 IRP action plan, which lists the specific steps PacifiCorp will take over the next two to four years to deliver resources in the preferred portfolio, includes the following action item associated with the new Wyoming wind resources:

> PacifiCorp will issue a wind resource request for proposals (RFP) for at least 1,100 MW of Wyoming wind resources that will qualify for federal wind production tax credits and achieve commercial operation by December 31, 2020.
>
> - April 2017, notify the Utah Public Service Commission of intent to issue the Wyoming wind resource RFP.
> - May-June, 2017, file a draft Wyoming wind RFP with the Utah Public Service Commission and the Washington Utilities and Transportation Commission.
> - May-June, 2017, file to open a Wyoming wind RFP docket with the Public Utility Commission of Oregon and initiate the Independent Evaluator RFP.
> - June-July, 2017, file a draft Wyoming wind RFP with the Public Utility Commission of Oregon and file a Public Convenience and Necessity (CPCN) application with the Public Service Commission of Wyoming.
> - By August 2017, obtain approval of the Wyoming wind resource RFP from the Public Utility Commission of Oregon, the Utah Public Service Commission and the Washington Utilities and Transportation Commission.
> - By August 2017, issue the Wyoming wind RFP to the market.
> - By October 2017, Wyoming wind RFP bids are due.
> - November-December, 2017, complete initial shortlist bid evaluation.
> - By January 2018, complete final shortlist bid evaluation, seek acknowledgment of the final shortlist from the Public Utility Commission of Oregon, and seek approval of winning bids from the Utah Public Service Commission.

- By March 2018, receive CPCN approval from the Wyoming Public Service Commission.
- Complete construction of new wind projects by December 31, 2020.[2]

Q. Please describe the resource procurement requirements in PacifiCorp's Oregon and Utah jurisdictions applicable to the new Wyoming wind resource action item included in the 2017 IRP action plan.

A. The Public Utility Commission of Oregon established competitive bidding requirements for certain resource acquisitions applicable to Oregon's investor-owned utilities (the Competitive Bidding Guidelines).[3] Because of the multi-state regulatory approach for cost recovery of PacifiCorp's generation assets and NPC, the new Wyoming wind resources will be subject to these Competitive Bidding Guidelines as it relates to cost recovery for Oregon's allocated share of costs. The new Wyoming wind resources described in the 2017 IRP action plan could exceed the 100 MW threshold size for any given project as established by the Competitive Bidding Guidelines. Therefore, procurement of these Wyoming wind resources is governed by these guidelines.

In addition, Utah's Energy Resource Procurement Act requires a competitive solicitation process before the acquisition of renewable resources greater than 300 MW.[4] While it is not certain whether a single wind resource acquired through a competitive bidding process will exceed 300 MW, PacifiCorp is proceeding with filings under the Utah Energy Resource Procurement Act because the total new wind resource capacity assumed to come online by the end of 2020 that is in the 2017 IRP preferred

[2] PacifiCorp 2017 Integrated Resource Plan, Volume I at 16-17 (Apr. 4, 2017).
[3] The Competitive Bidding Guidelines were established by OPUC Order No. 06-446 in Docket No. UM 1182.
[4] *See* Utah Code Ann. § 54-17-201 *et. seq.*

portfolio exceeds the 300 MW threshold established by Utah's statute.

Q. Please summarize PacifiCorp's progress with the Wyoming wind resource procurement action item outlined in the 2017 IRP action plan.

A. PacifiCorp notified the Utah Public Service Commission ("UPSC") of its intent to issue the Wyoming wind resource RFP (the "2017R RFP") on April 17, 2017. This notification initiated the process for the UPSC to hire an independent evaluator ("IE") to oversee the 2017R RFP process. PacifiCorp subsequently filed its draft 2017R RFP with the UPSC on June 16, 2017. The draft 2017R RFP is seeking bids for Wyoming wind resources that can be placed in service by the end of 2020 and that are capable of interconnecting to, and/or delivering energy and capacity across, PacifiCorp's transmission system in Wyoming. PacifiCorp is encouraging bidders to offer proposals under a range of different structures, including power purchase agreements ("PPAs") and build-transfer agreements.

PacifiCorp also filed an application with the Public Utility Commission of Oregon requesting that a docket be opened to approve the 2017R RFP and to appoint its own IE to oversee the 2017R RFP process.

Since the 2017 IRP was filed, PacifiCorp determined that the 2017R RFP does not need to be filed and approved by the Washington Utilities and Transportation Commission.

In his testimony, Mr. Chad A. Teply addresses the construction schedule for the new Wyoming wind resources.

Q. What is the timing of the 2017R RFP and how does it compare with PacifiCorp's proposed Wyoming CPCN schedule?

A. PacifiCorp anticipates releasing the 2017R RFP to the market by the end of August 2017 and receiving bids in the first half of October 2017. PacifiCorp plans to have its analysis of bids completed in early January 2018. After finalizing its bid analysis, PacifiCorp will make a supplemental filing in this docket, so that parties and the Commission can review and respond to project-specific information and the associated economic analysis confirming the net customer benefits from the Combined Projects. Maintaining implementation schedules for the Wind Projects, the Transmission Projects, and the 2017R RFP will require a conditional Wyoming CPCN, subject to final acquisition of all rights-of-ways, for the Transmission Projects under the schedule included in the application.

Q. Why will PacifiCorp's benchmark resources play an important role in the 2017R RFP?

A. PacifiCorp's benchmark resources will provide an alternative contracting-and-implementation cost basis that reflects competitive market-equipment-and-construction costs while promoting participation from market bids offering other project-delivery structures. PacifiCorp anticipates receiving bids in response to the 2017R RFP under a range of structures. Development and submittal of benchmark resources expand competitive-market offerings under a commercial structure that would otherwise not be available.

Q. Why is PacifiCorp not waiting until completion of the 2017R RFP to file its applications with states for approval of the Wind Projects?

A. The Combined Projects under review in this Application are unique. The Wind Projects and Transmission Projects are time-sensitive and codependent. These unique attributes make it impossible to complete the 2017R RFP before initiating review of the Transmission Projects without jeopardizing the in-service dates that are critical to delivering the customer benefits summarized later in my testimony. As described by Mr. Vail, the critical-path schedule for the Transmission Projects is the CPCN procedural schedule. If PacifiCorp were to wait for the 2017R RFP to finish in the first quarter of 2018 to begin lengthy resource review processes, it would not be possible to place the Transmission Projects in service by the end of 2020, which would eliminate the net customer benefits of this time-sensitive opportunity.

Nonetheless, PacifiCorp will fully and appropriately demonstrate the net customer benefits of the Combined Projects using market-based information from competitive procurement processes. To support this objective, PacifiCorp has initiated this process with proxy benchmark resource information that can ultimately be validated using project-specific information and associated economic analysis from the 2017R RFP.

Q. Did PacifiCorp include an action item for the Aeolus-to-Bridger/Anticline Line in its 2017 IRP action plan?

A. Yes. The 2017 IRP action plan includes the following action item associated with the Aeolus-to-Bridger/Anticline Line:

> By December 31, 2020, PacifiCorp will build the 140-mile, 500 kV transmission line running from the Aeolus substation near Medicine Bow,

Wyoming, to the Jim Bridger power plant (a sub-segment of the Energy Gateway West transmission project). This includes pursuing regulatory review and approval as necessary.

- June-July 2017, file a CPCN application with the Wyoming Public Service Commission.
- By March 2018, receive conditional CPCN approval from the Wyoming Public Service Commission pending acquisition of rights of way.
- By December 2018, obtain Wyoming Industrial Siting permit and issue EPC limited notice to proceed.
- Complete construction of the transmission line by December 31, 2020.[5]

Q. Please summarize PacifiCorp's progress with the Aeolus-to-Bridger/Anticline Line action item in the 2017 IRP action plan.

A. This application is being filed consistent with the 2017 IRP action plan to pursue regulatory review and approval. Mr. Vail addresses the construction schedule for the Aeolus-to-Bridger/Anticline Line and the 230 kV Network Upgrades identified in this Application.

SYSTEM MODELING METHODOLOGY

Q. Please summarize the methodology PacifiCorp used in its system analysis of the Combined Projects.

A. PacifiCorp relied upon the same modeling tools used to develop and analyze resource portfolios in its 2017 IRP to refine and update its analysis of the Combined Projects. These modeling tools calculate system PVRR by identifying least-cost resource portfolios and dispatching system resources over a 20-year forecast period (2017–2036). Net customer benefits are calculated as the PVRR(d) between two simulations of PacifiCorp's system. One simulation includes the Combined Projects, and the other simulation excludes the Combined Projects. Customers are expected to realize benefits

[5] PacifiCorp 2017 Integrated Resource Plan, Volume I at 17 (Apr. 4, 2017).

when the system PVRR with the Combined Projects is lower than the system PVRR without the Combined Projects. Conversely, customers would experience increased costs if the system PVRR with the Combined Projects were higher than the system PVRR without the Combined Projects.

Q. What modeling tools did PacifiCorp use to perform its system analysis of the Combined Projects?

A. PacifiCorp used the System Optimizer ("SO") model and the Planning and Risk model ("PaR") to develop resource portfolios and to forecast dispatch of system resources in simulations with and without the Combined Projects.

Q. Please describe the SO model and PaR.

A. The SO model is used to develop resource portfolios with sufficient capacity to achieve a target planning-reserve margin. The SO model selects a portfolio of resources from a broad range of resource alternatives by minimizing the system PVRR. In selecting the least-cost resource portfolio for a given set of input assumptions, the SO model performs time-of-day, least-cost dispatch for existing resources and prospective resource alternatives, while considering the cost-and-performance characteristics of existing contracts and prospective demand-side-management ("DSM") resources—all within or connected to PacifiCorp's system. The system PVRR from the SO model reflects the cost of existing contracts, wholesale-market purchases and sales, the cost of new and existing generating resources (fuel, fixed and variable operations and maintenance, and emissions, as applicable), the cost of new DSM resources, and levelized revenue requirement of capital additions for existing coal resources and potential new generating resources.

PaR is used to develop a chronological unit commitment and dispatch forecast of the resource portfolio generated by the SO model, accounting for operating reserves and the volatility and uncertainty in key system variables. PaR captures volatility and uncertainty in its unit commitment and dispatch forecast by using Monte Carlo sampling of stochastic variables, which include load, wholesale electricity and natural-gas prices, hydro generation, and thermal unit outages. PaR uses the same common input assumptions that are used in the SO model, with resource-portfolio data provided by the SO model results. The PVRR from PaR reflects a distribution of system variable costs, including variable costs associated with existing contracts, wholesale-market purchases and sales, fuel costs, variable operations and maintenance costs, emissions costs, as applicable, and costs associated with energy or reserve deficiencies. Fixed costs that do not change with system dispatch, including the cost of DSM resources, fixed operations and maintenance costs, and the levelized revenue requirement of capital additions for existing coal resources and potential new generating resources, are based on the fixed costs from the SO model, which are combined with the distribution of PaR variable costs to establish a distribution of system PVRR for each simulation.

Q. How has PacifiCorp historically used the SO model and PaR?

A. PacifiCorp uses the SO model and PaR to produce and evaluate resource portfolios in its IRP. PacifiCorp also uses these models to analyze resource-acquisition opportunities, resource retirements, resource capital investments, and system transmission projects. The models were used to support the successful acquisition of the Chehalis combined-cycle plant, to support selection of the Lake Side 2 combined-cycle resource through a RFP process, and to evaluate installation of emissions control equipment. These models will also be used to evaluate bids in the soon-to-be-issued 2017R RFP.

Q. Are the SO model and PaR the appropriate tools for analyzing the net customer benefits of the Combined Projects?

A. Yes. The SO model and PaR are the appropriate modeling tools when evaluating significant capital investment that influence PacifiCorp's resource mix and affect least-cost dispatch of system resources. The SO model simultaneously and endogenously evaluates capacity and energy trade-offs associated with resource capital projects and is needed to understand how the type, timing, and location of future resources might be affected by the Combined Projects. PaR provides additional granularity on how the Combined Projects are projected to affect system operations, recognizing that key system conditions are volatile and uncertain. Together, the SO model and PaR are best suited to perform a net-benefit analysis for the Combined Projects that is consistent with long-standing least-cost, least-risk planning principles applied in PacifiCorp's IRP.

Q. How did PacifiCorp use PaR to assess stochastic system-cost risk associated with the Combined Projects?

A. Just as it evaluates resource portfolio alternatives in the IRP, PacifiCorp uses the stochastic-mean PVRR and risk-adjusted PVRR, calculated from PaR study results, to assess the stochastic system cost risk of the Combined Projects. With Monte Carlo sampling of stochastic variables, PaR produces a distribution of system variable costs. The stochastic-mean PVRR is the average of net variable operating costs from the distribution of system variable costs, combined with system fixed costs from the SO model. PacifiCorp uses a risk-adjusted PVRR to evaluate stochastic system cost risk. The risk-adjusted PVRR incorporates the expected value of low-probability, high-cost outcomes. The risk-adjusted PVRR is calculated by adding five percent of system variable costs, from the 95th percentile of the distribution of system variable costs, to the stochastic-mean PVRR.

When applied to the analysis of the Combined Projects, the stochastic-mean PVRR represents the expected level of system costs from cases with and without the Wind Projects and the Transmission Projects. The risk-adjusted PVRR is used to assess whether the Combined Projects cause a disproportionate increase to system variable costs under low-probability, high-cost system conditions.

Q. Did PacifiCorp analyze how other assumptions affect its economic analysis of the Combined Projects?

A. Yes. In addition to assessing stochastic system cost risk, PacifiCorp analyzed the Combined Projects under a range of assumptions regarding wholesale market prices and CO_2 policy ("price-policy") assumptions. These assumptions drive NPC-related benefits, and so it is important to understand how the net-benefit analysis is affected under a range of potential outcomes. PacifiCorp developed low, medium, and high scenarios for the market price of electricity and natural gas and zero, medium, and high CO_2 price scenarios. Each pair of model simulations—with and without the Combined Projects, in both the SO model and PaR—was analyzed under each combination of these price-policy assumptions. I summarize the assumptions for each price-policy scenario later in my testimony.

PacifiCorp also completed two sensitivity studies to assess how certain factors affect the net benefits of the Combined Projects. The first sensitivity quantifies how the net benefits of the Combined Projects are affected by the depreciable life assumed for the new Wind Projects. PacifiCorp's base analysis assumes a 30-year depreciable life when calculating revenue requirement associated with the Wind Projects. Considering that wind facilities with modern equipment might continue operating over a longer period, this sensitivity quantifies the economic impact if the depreciable life of the Wind Projects were reset at 40 years.

The second sensitivity quantifies how the net benefits of the Combined Projects are affected when paired with the wind repowering project, the subject of a concurrent application. Consistent with PacifiCorp's wind repowering application, this sensitivity assumes approximately 999 MW of existing wind resource capacity is upgraded with modern equipment in the 2019-to-2020 time frame.

Q. How much new Wyoming wind capacity did PacifiCorp analyze in its economic analysis of the Combined Projects for this Application?

A. PacifiCorp assumed approximately 1,180 MW of new Wyoming wind resources for all SO model and PaR simulations that include the Combined Projects. As described by Mr. Teply, this includes approximately 860 MW from the Wind Projects, which can achieve commercial operation by year-end 2020. The remaining 320-MW balance of new wind resource capacity is associated with certain qualifying facility projects (the "QF Projects") that are located in the Aeolus area, have executed PPAs with PacifiCorp, and have preferential positions in the transmission interconnection queue. The QF Projects are reasonably expected to interconnect with PacifiCorp's transmission system after the Aeolus-to-Bridger/Anticline Line is placed in service and are assumed to achieve commercial operation at the end of 2021, consistent with the terms in their PPAs. Because the QF Projects are not expected to be able to interconnect with PacifiCorp's transmission system without the Aeolus-to-Bridger/Anticline Line, they are only included in the SO model and PaR simulations that include the Combined Projects.

Q. Why is the total capacity of the new Wyoming wind resources included in PacifiCorp's economic analysis of the Combined Projects different from the capacity included in the 2017 IRP preferred portfolio?

A. As discussed in the testimony of Mr. Teply, PacifiCorp is seeking approvals for the specific wind projects that it will offer as benchmark resources in the 2017R RFP. This includes three projects (Ekola Flats, TB Flats I, and TB Flats II) being developed by a third party totaling approximately 750 MW and a fourth, 110-MW project (McFadden Ridge II), which PacifiCorp is developing on a site it controls. The capacity of the specific Wind Projects that will be offered as benchmark resources in the 2017R RFP (approximately 860 MW), when combined with the total capacity of the QF Projects (320 MW), totals 1,180 MW. This level of procurement is consistent with PacifiCorp's 2017 IRP action item to procure *at least* 1,100 MW of Wyoming wind resources. PacifiCorp will evaluate the level of Wyoming wind resource procurement that will maximize customer benefits, up to approximately 1,270 MW of new resource interconnections enabled by the Aeolus-to-Bridger/Anticline Line, based on specific bids submitted in response to the 2017R RFP.

Q. What key assumptions did PacifiCorp update since analyzing the new Wyoming wind resources and the Aeolus-to-Bridger/Anticline Line in its 2017 IRP?

A. Beyond the price-policy assumptions used to analyze a range of NPC-related benefits, PacifiCorp's economic analysis reflects updated assumptions for up-front capital costs, run-rate operating costs, and energy output specific to the Wind Projects and QF Projects described earlier in my testimony. PacifiCorp's analysis assumes an up-front capital investment for the Wind Projects totaling approximately [redacted] and are assumed to operate at a capacity-weighted-average-annual capacity factor of [redacted]. The PPA price paid to the QF Projects add [redacted] to total-system NPC beginning 2022, rising to [redacted] by the end of their contract terms in 2041. The QF Projects are assumed to operate at an aggregate capacity factor of 40.7 percent. The cost and performance assumptions for the Wind Projects and the QF Projects studied for this application are summarized in Confidential Exhibit RMP___(RTL-1).

The up-front capital investment for the Aeolus-to-Bridger/Anticline Line is [redacted], consistent with the capital cost assumed in PacifiCorp's 2017 IRP. The assumed up-front capital investment for the 230 kV Network Upgrades, reflecting costs to interconnect the Wind Projects, total [redacted]. The cost and performance assumptions for the Transmission Projects studied for this application are also summarized in Confidential Exhibit RMP___(RTL-1).

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

A. No. While the up-front capital cost of the Transmission Projects will contribute to retail-customer rate base, the revenue requirement for these investments will be partially offset by incremental revenue from other transmission customers. The up-front transmission costs will flow into PacifiCorp's formula transmission rate under its Open Access Transmission Tariff ("OATT") and generate revenue credits that offset costs for retail customers.

PacifiCorp's merchant function, which uses PacifiCorp's transmission system to serve retail-customer load and to manage retail-customer NPC through off-system market sales and purchases, is the largest user of PacifiCorp's transmission system. However, other transmission customers pay OATT-based transmission rates that generate revenue credits and offset the cost of PacifiCorp's transmission revenue requirement. As discussed in Mr. Vail's testimony, the Transmission Projects are considered network transmission assets under PacifiCorp's OATT and therefore will be given rolled-in treatment under PacifiCorp's transmission formula rate. Over recent history, these revenue credits have accounted for approximately 12 percent of PacifiCorp's transmission revenue requirement. Based on this recent history, PacifiCorp's analysis assumes its retail customers pay 88 percent of the revenue requirement from the up-front capital cost for the Transmission Projects after accounting for an assumed 12 percent revenue credit from other transmission customers.

Q. How did PacifiCorp model de-rates to its Wyoming 230 kV transmission system when evaluating the Combined Projects?

A. In its final 2017 IRP resource-portfolio screening process, PacifiCorp identified and quantified reliability benefits associated with the Aeolus-to-Bridger/Anticline Line. This new transmission project will eliminate de-rates caused by outages on 230 kV transmission-system elements. Historical outages on this part of PacifiCorp's transmission system indicate an average de-rate of 146 MW over approximately 88 outage days per year, which equates to approximately one 146-MW, twenty-four hour outage every four days. Without knowing when these events might occur, de-rates on the existing 230 kV transmission system were captured in the SO model and PaR as a 36.5 MW reduction in the transfer capability from eastern Wyoming to the Aeolus area. In simulations that include the Combined Projects, this de-rate assumption was eliminated when the new transmission assets are placed in service at the end of October 2020.

Q. How did PacifiCorp model line-loss benefits associated with the Transmission Projects when performing its economic analysis of the Combined Projects?

A. Line-loss benefits are only applicable in those simulations where the Transmission Projects are built and therefore were only considered in the simulations that include the Combined Projects. When the Aeolus-to-Bridger/Anticline Line is added in parallel to the existing transmission lines, resistance is reduced, which lowers line losses. With reduced line losses, an incremental 11.6 average MW ("aMW") of energy, which equates to approximately 102 gigawatt hours ("GWh"), will be able to flow out of eastern Wyoming each year. The line-loss benefit was reflected in the SO model and PaR by reducing northeast Wyoming load by approximately 11.6 aMW each year.

Q. Did PacifiCorp analyze potential EIM benefits in its economic analysis of the Combined Projects?

A. Yes. In its final 2017 IRP resource-portfolio screening process, PacifiCorp described how the EIM can provide potential benefits when incremental energy is added to transmission-constrained areas of Wyoming. Unscheduled or unused transmission from participating EIM entities enables more efficient power flows within the hour. With increasing participation in the EIM, there will be increasing opportunities to move incremental energy from Wyoming to offset higher-priced generation in the PacifiCorp system or other EIM participants' systems. The more efficient use of transmission that is expected with growing participation in the EIM was captured in the economic analysis of the Combined Projects by increasing the transfer capability between the east and west sides of PacifiCorp's system by 300 MW (from the Jim Bridger plant to south-central Oregon). The ability to more efficiently use intra-hour transmission from a growing list of EIM participants is not driven by the Combined Projects; however, this increased connectivity provides the opportunity to move low-cost incremental energy out of transmission-constrained areas of Wyoming.

ANNUAL REVENUE REQUIREMENT MODELING METHODOLOGY

Q. In addition to the system 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 the Combined Projects?

A. Yes. The system PVRR from the SO model and PaR was calculated from an annual stream of forecasted revenue requirement over a 20-year time frame, consistent with the planning period in the IRP. The annual stream of forecasted revenue requirement captures nominal revenue requirement for non-capital items (*i.e.*, NPC, fixed operations and maintenance, etc.) and levelized revenue requirement for capital expenditures. To estimate the annual revenue-requirement impacts of the Combined

Projects, capital costs for the Wind Projects and the Transmission Projects 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 SO model and PaR 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.

Consider the potential implications of modeling nominal capital revenue requirement for a future generating resource needed in 2036, the last year of the 2017 IRP planning period. If nominal capital revenue requirement were assumed, the model would capture in its economic assessment of resource alternatives the highest, first-year revenue requirement capital cost without having any foresight into the potential benefits that resource would provide beyond 2036. If nominal capital costs were applied, the model's economic assessment of resource alternatives for the 2036 resource need would inappropriately favor less capital-intensive projects or projects having longer asset lives, even if those alternatives would increase system costs over their remaining life. Levelized capital costs for assets that have different lives and in-service dates is an established way to address these types of distortions in the comparative economic analysis of resource alternatives.

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

A. In the simulations that include the Combined Projects, the annual stream of costs for the Wind Projects, including levelized capital and PTCs, the QF Projects, and the Transmission Projects are temporarily removed from the annual stream of costs used to calculate the stochastic-mean PVRR. The differential in the remaining stream of annual costs, which includes all system costs except for those associated with the Combined Projects and the QF Projects, represents the net system benefit caused by the Combined Projects.

These data are disaggregated to isolate the estimated annual NPC benefits, other non-NPC variable-cost benefits (*i.e.*, variable operations and maintenance and emissions costs for those scenarios that include a CO_2 price assumption), and fixed-cost benefits. To complete the annual revenue-requirement forecast, the change in costs for the Combined Projects and the QF Projects, including nominal capital revenue requirement and PTCs, are added back in with the annual system net benefits caused by the Combined Projects.

Q. Over what time frame did PacifiCorp estimate the change in annual revenue requirement due to the Combined Projects?

A. The change in annual revenue requirement was estimated through 2050. This captures the full 30-year life of the Wind Projects.

Q. What is the assumed life of the Transmission Projects?

A. PacifiCorp assumed a 62-year life for the Transmission Projects. The Transmission Projects will continue to provide system benefits well beyond 2050 when the Wind

Projects are fully depreciated. These additional benefits are not reflected in PacifiCorp's economic analysis.

Q. How did PacifiCorp calculate the annual net benefits caused by the Combined Projects beyond the 20-year forecast period used in PaR?

A. The PaR-forecast period runs from 2017 through 2036. The change in net system benefits caused by the Combined Projects over the 2028-through-2036 time frame, expressed in dollars-per-MWh of incremental energy output from the Wind Projects and the QF Projects, were used to estimate the change in net system benefits from 2037 through 2050. This calculation was performed in several steps.

First, the net system benefits caused by the Combined Projects were divided by the change in incremental energy expected from the Wind Projects and the QF Projects, as modeled in PaR over the 2028-through-2036 time frame. Next, the net system benefits per MWh of incremental energy from the Wind Projects and the QF Projects over the 2028-through-2036 time frame were levelized. These levelized results were extended out through 2050 at inflation. The levelized net system benefits per MWh of incremental energy output from the Wind Projects and the QF Projects over the 2037-through-2050 time frame were then multiplied by the change in incremental energy output from the Wind Projects and the QF Projects over the same period.

Q. Why did PacifiCorp use PaR results from the 2028-through-2036 time frame to extend system cost impacts out through 2050?

A. Consistent with the 2017 IRP, PacifiCorp's economic analysis of the Combined Projects assumes the Dave Johnston coal plant, located in eastern Wyoming, retires at the end of 2027. When this plant is assumed to retire, transmission congestion affecting energy output from resources in eastern Wyoming, where the Wind Projects and the QF Projects are located, is reduced. The incremental energy output from the Wind Projects and the QF Projects provides more system benefits when not constrained by transmission limitations. Consequently, the net-system benefits caused by the Combined Projects over the 2028-through-2036 time frame, after Dave Johnston is assumed to retire, is representative of net system benefits that could be expected beyond 2036.

Q. Did PacifiCorp calculate a PVRR(d) for the Combined Projects using its estimate of annual revenue requirement impacts projected out through 2050?

A. Yes.

PRICE-POLICY SCENARIOS

Q. Please explain why price-policy scenarios are important when analyzing the Combined Projects.

A. Wholesale-power prices, often set by natural-gas prices, and the system cost impacts of potential CO_2 policies influence the forecast of net system benefits from the Combined Projects. Wholesale-power prices and CO_2 policy outcomes affect 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 the NPC benefits, non-NPC variable-cost benefits, and system fixed-cost benefits of the Combined Projects. Because wholesale-power prices and CO_2 policy outcomes are both uncertain and important drivers to the economic analysis, PacifiCorp studied the economics of the Combined Projects under a range of different price-policy scenarios.

Q. What price-policy scenarios did PacifiCorp use in its economic analysis of the Combined Projects?

A. PacifiCorp analyzed the Combined Projects under nine different price-policy scenarios. PacifiCorp developed three wholesale-power price scenarios (low, medium, and high), and similarly developed three CO_2 policy scenarios (zero, medium, and high). The nine price-policy scenarios developed for the economic analysis of the Combined Projects reflect different combinations of these scenario assumptions.

Considering that there is a high level of correlation between wholesale-power prices and natural-gas prices, the wholesale-power price scenarios were based on a range of natural-gas price assumptions. This ensures consistency between power price and natural-gas price assumptions for each scenario. PacifiCorp implemented its CO_2 policy assumptions through a CO_2 price, expressed in dollars-per-ton.

While it is unlikely that the CPP will be implemented in its current form, it is possible that future CO_2 policies targeting electric-sector emissions could be adopted and impose incremental costs to drive emissions reductions. CO_2 price assumptions used in the price-policy scenarios are not intended to mimic a specific type of policy mechanism (*i.e.*, a tax or an allowance price under a cap-and-trade program), but are intended to recognize that there might be future CO_2 policies that impose a cost to reduce emissions. Table 1 summarizes the nine price-policy scenarios used to analyze the Combined Projects.

Table 1. Price-Policy Scenarios

Price-Policy Scenario	Natural-Gas Prices (Levelized $/MMBtu)*	CO_2 Price Description
Low Gas, Zero CO_2	$3.19	$0/ton
Low Gas, Medium CO_2	$3.19	$3.41/ton in 2025 growing to $14.40/ton in 2036
Low Gas, High CO_2	$3.19	$4.73/ton in 2025 growing to $38.42/ton in 2036
Medium Gas, Zero CO_2	$4.07	$0/ton
Medium Gas, Medium CO_2	$4.13	$3.41/ton in 2025 growing to $14.40/ton in 2036
Medium Gas, High CO_2	$4.13	$4.73/ton in 2025 growing to $38.42/ton in 2036
High Gas, Zero CO_2	$5.83	$0/ton
High Gas, Medium CO_2	$5.83	$3.41/ton in 2025 growing to $14.40/ton in 2036
High Gas, High CO_2	$5.83	$4.73/ton in 2025 growing to $38.42/ton in 2036
*Nominal levelized Henry Hub natural-gas price from 2018 through 2036.		

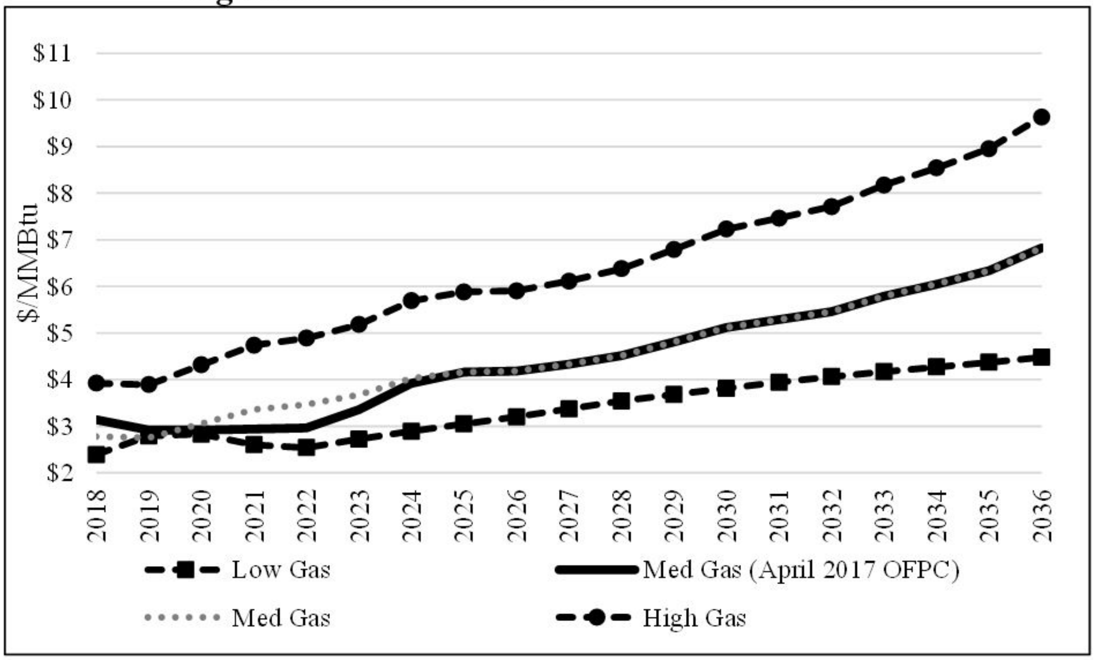
Q. Please describe the natural-gas price assumptions used in the price-policy scenarios.

A. The medium-natural-gas-price assumptions that are paired with zero CO_2 prices reflect natural-gas prices from PacifiCorp's official forward price curve ("OFPC") dated April 26, 2017. The OFPC uses observed forward market prices as of April 26, 2017, for 72 months, followed by a 12-month transition to natural-gas prices based on a forecast developed by [redacted]. The low-, medium-, and high-natural-gas price assumptions used for all other scenarios were chosen after reviewing a range of credible third-party forecasts developed by [redacted], and the U.S. Department of Energy's Energy Information Administration. Exhibit RMP___(RTL-2) shows the range in natural-gas price assumptions from these third-party forecasts relative to those adopted for the price-policy scenarios to evaluate the Combined Projects.

The low-natural-gas price assumption was derived from a low-price scenario developed by [redacted], which is based on surging growth in price-inelastic associated gas, technology improvements, stagnant liquefied-natural-gas exports, and an ever-expanding resource base. The medium-natural-gas price assumption, which is used beyond month 84 in the April 2017 OFPC, and in all months when medium-natural-gas prices are paired with medium or low CO_2 price assumptions, is based on a base-case forecast from [redacted] that is reasonably aligned with other base-case forecasts. The high-natural-gas price assumption was based on a high-price scenario from [redacted]. The high-price scenario is based on risk-aversion, whereby natural-gas developers are reluctant to commit capital before demand, and the associated price response, materializes. This gives rise to exaggerated boom-bust cycles (cyclical periods of high prices and low prices). PacifiCorp smoothed the boom-bust cycle in the third party's high-price scenario because the specific timing of these cycles are extremely difficult to project with reasonable accuracy.

Figure 1 shows Henry Hub natural-gas price assumptions from the April 2017 OFPC, low-, medium-, and high-natural-gas price scenarios. The April 2017 OFPC forecast only differs from the medium-natural-gas-price assumption in that it reflects observed-market forwards through the first 72 months followed by a twelve-month transition to [redacted]'s base-case forecast.

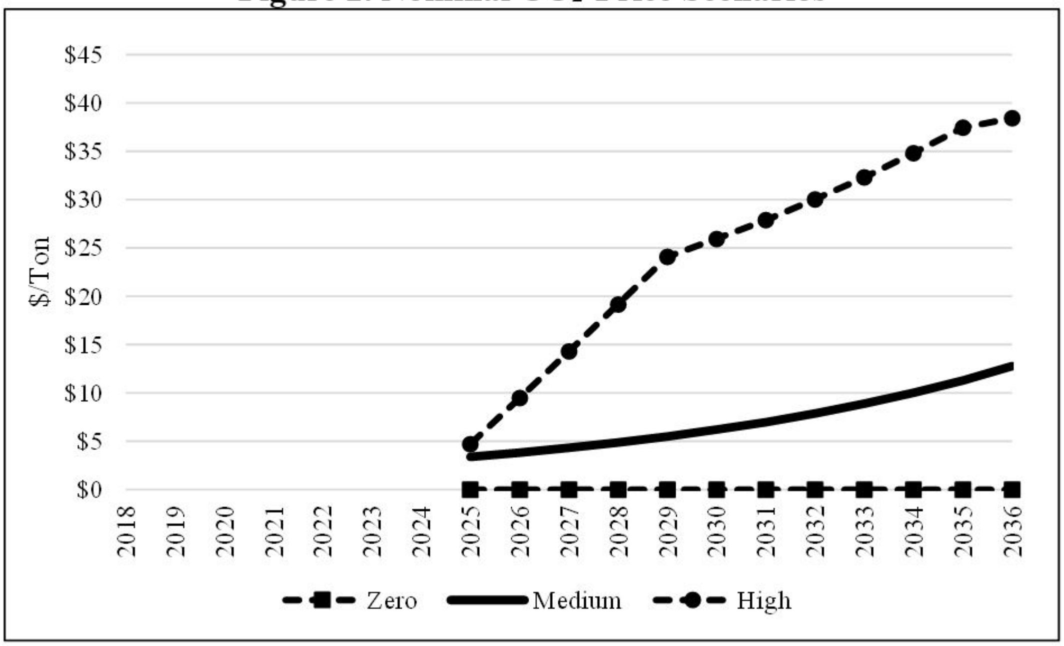
Figure 1. Nominal Natural-Gas Price Scenarios



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

A. As with natural-gas prices, the medium- and high-CO_2 price assumptions are based on third-party projections from [redacted] and [redacted]. Both forecasters assume CO_2 prices start in 2025. To bracket the low end of potential-policy outcomes, PacifiCorp assumes there are no future policies adopted that would require incremental costs to achieve emissions reductions in the electric sector. In this scenario, the assumed CO_2 price is zero. Figure 2 shows the three CO_2 price assumptions used to analyze the Combined Projects.

Figure 2. Nominal CO_2-Price Scenarios



SYSTEM MODELING PRICE-POLICY RESULTS

Q. Please summarize the PVRR(d) results calculated from the SO model and PaR through 2036.

A. Table 2 summarizes the PVRR(d) results for each price-policy scenario. The PVRR(d) between cases with and without the Combined Projects are shown from the SO model and from PaR, which was used to calculate both the stochastic-mean PVRR(d) and the risk-adjusted PVRR(d). The data that was used to calculate the PVRR(d) results shown in the table are provided as Exhibit RMP___(RTL-3).

Table 2. SO Model and PaR PVRR(d) (Benefit)/Cost of the Combined Projects ($ million)

Price-Policy Scenario	SO Model PVRR(d)	PaR Stochastic-Mean PVRR(d)	PaR Risk-Adjusted PVRR(d)
Low Gas, Zero CO_2	$121	$77	$74
Low Gas, Medium CO_2	$73	$32	$26
Low Gas, High CO_2	($84)	($133)	($147)
Medium Gas, Zero CO_2	($19)	($57)	($66)
Medium Gas, Medium CO_2	($85)	($111)	($124)
Medium Gas, High CO_2	($156)	($224)	($242)
High Gas, Zero CO_2	($304)	($260)	($280)
High Gas, Medium CO_2	($318)	($272)	($293)
High Gas, High CO_2	($396)	($409)	($437)

Over a 20-year period, the Combined Projects reduce customer costs in seven out of nine price-policy scenarios price-policy scenarios. This trend occurs in the PVRR(d) calculated from both the SO model and PaR. The only price-policy scenarios without net customer benefits are those assuming the lowest natural-gas prices when paired with either medium or zero-CO_2 price assumptions. Under the central price-policy scenario, assuming medium-natural-gas prices and medium-CO_2 prices, the PVRR(d) benefits range between $85 million, when based upon SO model results, and $124 million, when based upon PaR-risk-adjusted results.

The PVRR(d) results show that the benefits of the Combined Projects increase with natural-gas prices and CO_2 prices, which increase NPC and other system variable cost benefits.

Q. Is there incremental customer upside to the PVRR(d) results calculated from the SO and PaR models through 2036?

A. Yes. The PVRR(d) results presented in Table 2 do not reflect the potential value of RECs generated by the incremental wind energy output from the Wind Projects. Customer benefits for all price-policy scenarios would improve by approximately $26 million for every dollar assigned to the incremental RECs that will be generated from the Wind Projects through 2036. Beyond potential REC-revenue benefits, the economic analysis of the Combined Projects does not reflect PacifiCorp's enhanced ability to comply with mandated reliability and performance standards the opportunity for further increases to the transfer capability across the Aeolus-to-Bridger/Anticline Line with the construction of additional segments of the Energy Gateway project.

Q. Why do the PaR results tend to show a different level of benefits from Combined Projects when compared to the results from the SO model?

A. The two models assess the system impacts of the Combined Projects in different ways. The SO model is designed to dynamically assess system dispatch, with less granularity than PaR, while optimizing the selection of resources to the portfolio over time. PaR is able to dynamically assess system dispatch, with more granularity than the SO model and with consideration of stochastic risk variables; however, PaR does not modify the type, timing, size and location of resources in the portfolio in response to its more detailed assessment of system dispatch.

Q. Does one of these two models provide a better assessment of the Combined Projects relative to the other?

A. No. The two models are simply different, and both are useful in establishing a range of benefits from the Combined Projects through the 20-year forecast period. Importantly, the PVRR(d) results from both models show customer benefits across all price-policy scenarios with consistent trends in the difference in PVRR(d) results between price-policy scenarios. The consistency in the trend of forecasted benefits between the two models, each having its own strengths, shows that the benefits from the Combined

Projects are robust across a range of price-policy assumptions and when analyzed using different modeling tools.

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

A. The risk-adjusted PVRR(d) results consistently show a slight increase in the benefits of the Combined Projects when compared to the stochastic-mean PVRR(d) results. This indicates that the Combined Projects reduce the risk of high-cost, low-probability outcomes that can occur due to volatility in stochastic variables like load, wholesale-market prices, hydro generation, and thermal-unit outages.

ANNUAL REVENUE REQUIREMENT PRICE-POLICY RESULTS

Q. Please summarize the PVRR(d) results calculated from the change in annual revenue requirement through 2050.

A. Table 3 summarizes the PVRR(d) results for each price-policy scenario calculated off of the change in annual nominal revenue requirement through 2050. The annual data over the period 2017 through 2050 that was used to calculate the PVRR(d) results shown in the table are provided as Exhibit RMP___(RTL-4).

Table 3. Nominal Revenue Requirement PVRR(d) (Benefit)/Cost of the Combined Projects ($ million)

Price-Policy Scenario	Annual Revenue Requirement PVRR(d)
Low Gas, Zero CO_2	$174
Low Gas, Medium CO_2	$93
Low Gas, High CO_2	($194)
Medium Gas, Zero CO_2	($53)
Medium Gas, Medium CO_2	($137)
Medium Gas, High CO_2	($317)
High Gas, Zero CO_2	($341)
High Gas, Medium CO_2	($351)
High Gas, High CO_2	($595)

When calculated through 2050, which covers the 30-year life of the Wind Projects, the Combined Projects reduce customer costs in seven out of nine price-policy scenarios. The only price-policy scenarios without net customer benefits are those assuming the lowest natural-gas prices when paired with either medium or zero-CO_2 price assumptions. The PVRR(d) results show customer benefits under the price-policy scenario with low natural-gas prices and high-CO_2 prices, in all three of the medium-natural-gas price scenarios, and in all three of the high-natural-gas price scenarios. Under the central price-policy scenario, assuming medium-natural-gas prices and medium-CO_2 prices, the PVRR(d) benefit is $137 million.

Consistent with the PVRR(d) results calculated from the SO model and PaR through 2036, the PVRR(d) results show that the benefits of the Combined Projects increase with natural-gas prices and CO_2 prices, which increase NPC and other system variable cost benefits.

Q. What causes the decrease in PVRR(d) benefits when calculated off of nominal revenue requirement through 2050 relative to the PVRR(d) results calculated from the SO model and PaR results through 2036?

A. The PVRR(d) calculated from estimated annual revenue requirement through 2050 reflects reduced incremental wind energy output beginning in 2042 after the QF Projects' PPAs end. Confidential Figure 3 shows the incremental change in wind energy output from the Wind Projects and the QF Projects. Incremental energy output associated with the Combined Projects is steady at approximately [redacted] GWh over the 2022-through-2041 period. Beyond 2041, energy output is approximately [redacted] GWh—[redacted]. This reduction in incremental wind energy output reduces NPC benefits and other system variable costs benefits over the last nine years of the PVRR(d) calculated off the change in nominal revenue requirement estimates through 2050. Consequently, the PVRR(d) calculated off the change in nominal revenue requirement through 2050 does not capture likely benefits associated with a potential extension of the QF Projects' PPAs or incremental procurement of additional Wyoming wind resources after the term of these PPAs end.

Confidential Figure 3. Change Incremental Wind Energy Output from the Wind Projects and QF Projects (GWh)

[redacted]

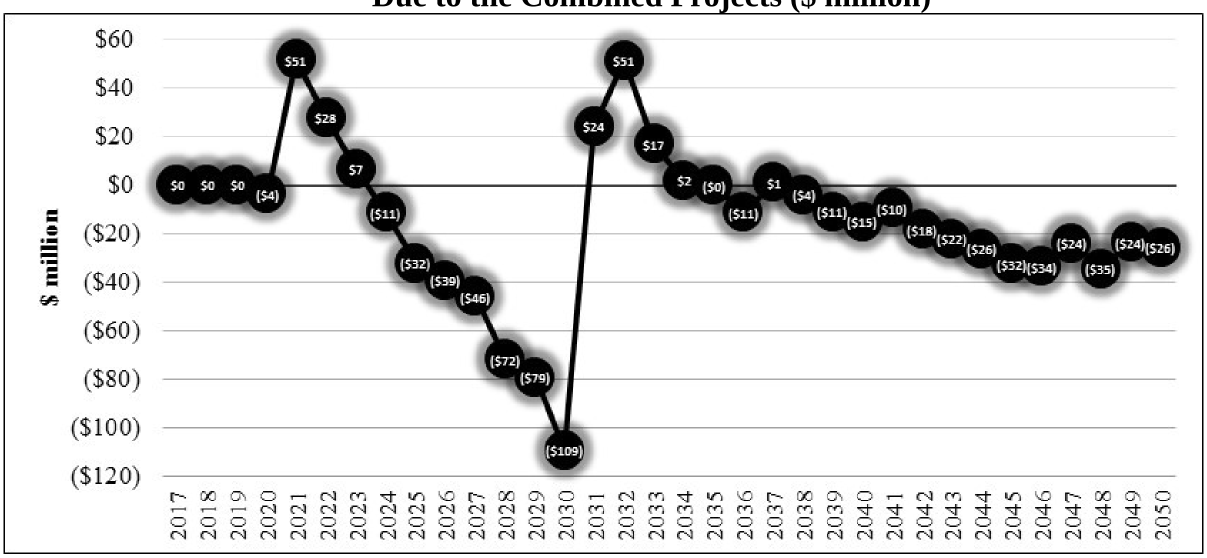
Q. **Is there incremental customer upside to the PVRR(d) results calculated from the change in estimated annual revenue requirement through 2050?**

A. Yes. As in the case with the PVRR(d) results calculated from the SO model and PaR results through 2036, the PVRR(d) results presented in Table 3 do not reflect the potential value of RECs produced by the Wind Projects. Customer benefits for all price-policy scenarios would improve by approximately $34 million for every dollar assigned to the incremental RECs that will be generated from the Wind Projects through 2050.

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

A. Figure 4 shows the estimated change in annual nominal-revenue requirement due to the Combined Projects for the medium-natural-gas and medium-CO_2-price-policy scenario on a total-system basis. The annual revenue requirement shown in the figure reflects all costs for the Combined Projects, including capital revenue requirement (*i.e.*, depreciation, return, income taxes, and property taxes) net of transmission revenue credits, operations and maintenance expenses, the Wyoming wind-production tax, incremental wind integration costs, and PTCs. The project costs are netted against system impacts of the Combined Projects, reflecting the change in NPC, emissions, non-NPC variable costs, and system fixed costs that are affected by, but not directly associated with, the Combined Projects.

Figure 4. Total-System Change in Annual Revenue Requirement Due to the Combined Projects ($ million)



In the initial year the Combined Projects come online, net system benefits offset partial-year capital revenue requirement. In 2021, the first full year the Combined Projects are in service, the change in total-system nominal revenue requirement increases by $51 million. This figure rapidly declines and crosses over from a net increase in nominal revenue requirement to a decrease in nominal revenue requirement beginning 2024—just four years after the first full year of operation. The net revenue requirement benefits persist and grow through 2030 as PTC benefits increase with inflation and the new equipment continues to depreciate. On a total-system basis, the change in annual revenue requirement is down by $109 million in 2030—the last year the Wind Projects produce PTCs. After the PTCs expire, annual revenue requirement increases. However, as the assets continue to depreciate, the Combined Projects once again begin producing annual revenue requirement savings beginning 2036. These annual benefits persist through 2050.

SENSITIVITY STUDY RESULTS

Q. Please summarize the results of the sensitivity that assumes the Wind Projects have a 40-year-depreciable life.

A. Table 4 summarizes the PVRR(d) results for the sensitivity assuming a 40-year life for the Wind Projects. To assess the relative impact of the 40-year life, the PVRR(d) results were calculated through 2036 based on SO model and PaR results and are presented alongside the benchmark study in which the Combined Projects were evaluated assuming a 30-year life for the Wind Projects. Medium-natural-gas and medium-CO_2 price-policy assumptions were applied to this sensitivity.

Table 4. 40-Year-Life Sensitivity
(Benefit)/Cost of the Combined Projects ($ million)

Model	Sensitivity PVRR(d)	Benchmark PVRR(d)	Change in PVRR(d)
SO Model	($106)	($85)	($21)
PaR Stochastic-Mean	($132)	($111)	($21)
PaR Risk-Adjusted	($145)	($124)	($21)

If the Wind Projects are depreciated over a 40-year life, reduced book depreciation would drive lower annual revenue requirement. In this sensitivity, PVRR(d) benefits increase by approximately $21 million relative to the benchmark case assuming a 40-year life for the Wind Projects.

Q. Please summarize the results of the sensitivity that analyzes the Combined Projects with wind repowering.

A. Table 5 summarizes the PVRR(d) results for the sensitivity assuming the Combined Projects are implemented along with wind repowering of approximately 999 MW of existing wind capacity. To assess the relative impact of wind repowering on the Combined Projects, the PVRR(d) results were calculated through 2036 based on SO model and PaR results and are presented alongside the benchmark study in which the Combined Projects were evaluated without repowering. Medium-natural-gas and medium-CO_2 price-policy assumptions were applied to this sensitivity.

Table 5. The Combined Projects with Wind Repowering Sensitivity (Benefit)/Cost ($ million)

Model	Sensitivity PVRR(d)	Benchmark PVRR(d)	Change in PVRR(d)
SO Model	($114)	($85)	($29)
PaR Stochastic-Mean	($104)	($111)	$8
PaR Risk-Adjusted	($116)	($124)	$8

When the Combined Projects are analyzed with the wind repowering project, PVRR(d) benefits increase by $29 million when assessed with the SO model. PaR shows a slight $8 million increase to the PVRR(d).

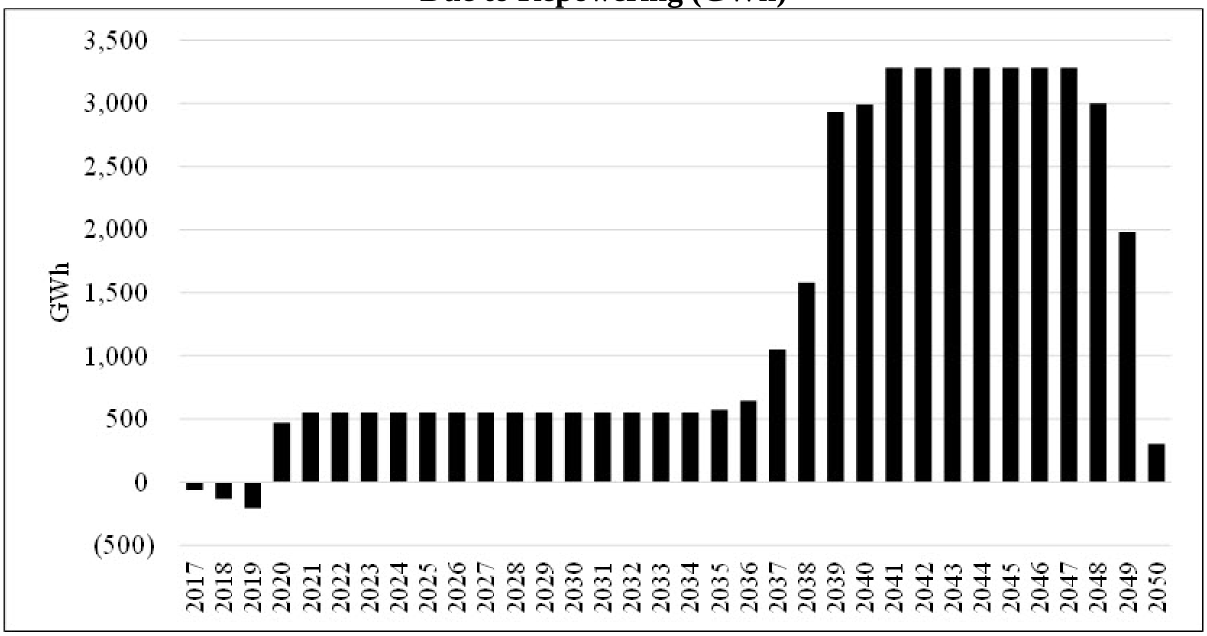
Q. Do the PaR results for this sensitivity indicate that the wind repowering project lowers customer benefits if implemented in parallel with the Combined Projects?

A. No. The sensitivity does not capture any of the incremental benefits from the wind repowering project that will occur just beyond the 2036 period, which is the last year simulated in the SO model and PaR. Consequently, the PVRR(d) results from the SO model and PaR do not capture the significant increase in the benefits from repowering that is associated with increased incremental energy output that will occur beyond 2036.

The change in wind energy output between cases with and without repowering experiences a step change in the 2036-through-2040 time frame, when the wind facilities within the repowering project scope that were originally placed in-service during the 2006-through-2010 time frame would otherwise have hit the end of their depreciable life. Before the 2036-through-2040 time frame, the period captured in the PVRR(d) results summarized in Table 5, the change in wind energy output from repowering reflects the incremental energy production that results from installing modern equipment on repowered wind assets. Beyond the 2036-through-2040 time frame, a period that is not captured in the PVRR(d) results reported in Table 5, the change in wind energy output between a case with and without repowering reflects the full energy output from the repowered wind facilities that would otherwise be retired.

Figure 5 shows the incremental change in wind energy output resulting from the repowering project. Incremental energy output associated with wind repowering progressively increases over the 2036-through-2040 period, as wind facilities originally placed in service in the 2006-through-2010 time frame would have otherwise hit the end of their lives. Before 2036, and once all of the wind resources within the project scope are repowered, the average annual incremental increase in wind energy output is approximately 551 GWh. Beyond 2040, and before the new equipment hits the end of its depreciable life, the average annual incremental increase in wind energy output is approximately 3,283 GWh. The value of this incremental wind-energy output associated with repowering adds substantial incremental benefits not reflected in the PVRR(d) results for this sensitivity that would more than offset the modest $8 million PVRR(d) incremental cost based on PaR results through 2036.

Figure 5. Change in Incremental Wind Energy Output
Due to Repowering (GWh)



CONCLUSION

Q. Please summarize the conclusions of your testimony.

A. PacifiCorp's analysis supports proceeding with its planned investments in the Wind Projects and Transmission Projects. The Wind Projects, which are enabled by the Transmission Projects will: (1) qualify for ten years of federal PTCs; (2) produce zero-fuel-cost energy that will lower NPC; (3) generate RECs, which can be sold in the market to create additional revenues that would lower net customer costs; and (4) help to decarbonize PacifiCorp's resource portfolio, which mitigates long-term risk associated with potential future state and federal policies targeting CO_2 emissions reductions from the electric sector.

The Transmission Projects will: (1) relieve congestion on the current transmission system in eastern Wyoming; (2) enable the additional wind resource interconnections; (3) provide critical voltage support to the Wyoming transmission network; (4) improve overall reliability of the transmission system and enhance PacifiCorp's ability to comply with mandated reliability and performance standards; (5) reduce line losses; and (6), create an opportunity for further increases to the transfer capability across the Aeolus-to-Bridger/Anticline Line with the construction of additional segments of the Energy Gateway project.

The economic analysis of the Combined 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 PacifiCorp's decision to invest in the Wind Projects and the Transmission Projects is in the public interest and approve the Application as filed, including the proposed ratemaking treatment for the new costs and benefits of the Combined Projects.

Q. Does this conclude your direct testimony?

A. Yes.