Application No. 18-04-___
Exhibit PAC/500
Witness: Rick T. Link

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

PACIFICORP

REDACTED

Direct Testimony of Rick T. Link

Economic Analysis

Installation of Selective Catalytic Reduction Systems and Wind Repowering

April 2018

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ATTACHED EXHIBITS

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power (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. QUALIFICATIONS

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 where I was 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 integrated resource plans (IRPs); have been directly involved in several resource request for proposals (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 financial modeling of environmental policies applicable to the electric sector 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. Briefly describe the responsibilities of your current position.

A. I am responsible for PacifiCorp's IRP, structured commercial business and valuation activities, long-term commodity price forecasts, and long-term load forecasts. Most relevant to this docket, I am responsible for the economic analysis used to screen resource investments.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have testified in regulatory proceedings in Oregon, Utah, Washington, and Wyoming.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

A. My testimony explains the economic analysis performed in 2012 that supported PacifiCorp's decisions to install selective catalytic reduction (SCR) emission control systems on Units 3 and 4 of the Jim Bridger generating plant. I also present and explain the economic analysis that shows PacifiCorp's decision to upgrade, or "repower", certain wind resources is prudent and provides significant customer benefits. I also summarize PacifiCorp's assessment of the wind repowering project in its 2017 IRP.

Q. Please summarize your testimony.

A. PacifiCorp's economic analysis of SCR emission control systems at Jim Bridger Units 3 and 4 demonstrate that these systems were expected to provide net customer benefits relative to alternatives that included conversion to natural gas and early retirement. Specifically, my testimony on the SCR systems at Jim Bridger Units 3 and 4 presents the following:

- A description of the methodology used to analyze the SCR systems required to continue operating Jim Bridger Units 3 and 4 as coal-fueled facilities.
- A base case economic analysis showing $183 million in total company present-value customer benefits from the SCR systems that are necessary to continue operating Jim Bridger Units 3 and 4 as coal-fueled assets.[1]
- Natural-gas price and carbon dioxide (CO_2) price scenario assumptions and results showing a range of economic outcomes that support the SCR systems in six of the nine scenarios studied.
- A description of an additional sensitivity showing that the Jim Bridger Units 3 and 4 SCR systems are favorable to both gas conversion and early retirement alternatives.

Additionally, my testimony provides the economic analysis that supports repowering approximately 999 megawatts (MW) of existing wind resource capacity located in Wyoming, Oregon, and Washington. The repowered wind facilities will qualify for an additional 10 years of federal production tax credits (PTCs), produce more energy, reset the 30-year depreciable life of the assets, and reduce run-rate operating costs. PacifiCorp's economic analysis of the wind repowering opportunity demonstrates that net benefits, which include federal PTC benefits, net power cost (NPC) benefits, other system variable-cost benefits, and system fixed-cost benefits, more than outweigh net project costs. My testimony on the wind repowering project demonstrates the following:

- The economic analysis shows net customer benefits in all scenarios analyzed.
- The wind repowering project will produce present-value net customer benefits, based on economic analysis over the remaining life of the repowered wind facilities, ranging between $121 million to $466 million.

[1] All results from the economic analyses presented in my testimony are stated on a total-company basis.

- Present-value gross customer benefits calculated over the remaining life of the repowered wind facilities range between $1.14 billion and $1.48 billion, which compares to present-value costs totaling $1.02 billion.

- These net and gross customer benefits are conservative, as they do not account for potential incremental benefits from renewable energy credits (RECs) and understate potential benefits from reduced CO_2 emissions.

- When measured over a 20-year period, the present value net customer benefits from wind repowering range between $139 million and $273 million, which does not account for the value of incremental energy output that will increase significantly beyond 2036.

III. JIM BRIDGER UNITS 3 AND 4

Methodology

Q. What model was used to evaluate the SCR systems for Jim Bridger Units 3 and 4?

A. PacifiCorp used its System Optimizer (SO) model to perform a present-value revenue requirement differential (PVRR(d)) economic analysis of the SCR emission control systems at Jim Bridger Units 3 and 4. This same analysis was presented in PacifiCorp's 2013 IRP and 2013 IRP Update. This same economic analysis was also used to support the Wyoming certificate of public convenience and necessity process for the SCR emission control systems at Jim Bridger Units 3 and 4 described in the testimony of Mr. Chad A. Teply (Exhibit PAC/400).

Q. Please describe the SO model and how it is used by PacifiCorp.

A. The SO model is a capacity expansion optimization tool that is used in PacifiCorp's IRP to produce resource portfolios in support of long-term system planning. The SO model is also used in PacifiCorp's analysis of resource acquisition opportunities and resource procurement activities. The SO model endogenously considers tradeoffs between operating and capital revenue requirement costs of both existing and prospective new resources while simultaneously evaluating tradeoffs in energy value between existing and prospective new resource alternatives.

Q. Why is the SO model an appropriate tool for analyzing incremental emission control equipment installations required on coal resources?

A. The SO model is the appropriate modeling tool when evaluating capital investment decisions and alternatives to those investments that might include early retirement and replacement or conversion of assets to natural gas. The SO model is capable of simultaneously and endogenously evaluating capacity and energy tradeoffs between emission control systems required to meet environmental regulations and a broad range of alternatives including fuel conversion, early retirement and replacement with greenfield resources, market purchases, demand-side management resources, and/or renewable resources. In this way, the SO model captures the cost implications of prospective emission control installation decisions by evaluating NPC impacts along with the impacts those decisions might have on future resource acquisition needs. This is particularly important when resource retirement and replacement is considered to be an environmental compliance alternative.

Q. How was the SO model used to analyze the PVRR(d) of the SCR emission control systems required for Jim Bridger Units 3 and 4?

A. For a range of market price scenarios, which I describe later in my testimony, two SO model simulations were completed—an optimized simulation and a change-case simulation. In the optimized simulation, the SO model determined whether continued operation of Jim Bridger Units 3 and 4 inclusive of incremental SCR emission control systems and other planned costs required to achieve compliance with environmental regulations was a lower cost solution than avoiding those expenses through early retirement and resource replacement or through conversion to natural gas. In the change-case simulation, the SO model was forced to produce a suboptimal decision by not allowing it to make the preferred decision that was made in the optimized simulation.

When the optimized simulation selected continued operations with incremental SCR emission control systems and other planned costs, then the change case was created by removing the SCR emission control systems as an alternative, allowing the SO model to select either an early retirement or gas-conversion alternative. In each of these change-case simulations, the SO model selected natural-gas conversion as a lower-cost alternative to early retirement. In scenarios where the optimized simulation selected conversion to natural gas, then the change case forced continued operations with incremental SCR emission control systems and other planned costs. The difference in total-company costs, inclusive of differences in NPC, operating costs and capital costs, between the two simulations for any given market-price scenario represents the PVRR(d), which establishes how favorable or unfavorable the incremental environmental capital investments planned for Jim Bridger Units 3 and 4 are in relation to the next best alternative.

Q. What incremental environmental investment costs were assumed for Jim Bridger Units 3 and 4?

A. Incremental environmental investment costs applied in the SO model include the cost of the SCR emission control systems required for Jim Bridger Units 3 and 4, along with projected costs required to achieve compliance with an array of known and prospective environmental regulations. This included costs to achieve compliance with the U.S. Environmental Protection Agency's mercury and air toxics standard, and costs to achieve compliance with prospective rules on coal-combustion residuals and cooling water intake structures. The incremental investment costs assumed in the SO model for Jim Bridger Units 3 and 4 along with other coal resources in PacifiCorp's fleet are summarized in Confidential Exhibit PAC/501.

Q. What resource-replacement alternatives were made available to the SO model in the event SCR emission control systems were not installed on Jim Bridger Units 3 and 4?

A. In addition to brownfield natural-gas conversion of Jim Bridger Units 3 and 4, the SO model was configured with a range of resource-replacement alternatives, which included:

- greenfield natural-gas resources;
- firm market purchases;
- demand-side management; and
- incremental wind resources.

Since the installation of SCR systems was required by December 31, 2015, for Jim Bridger Unit 3 and by December 31, 2016, for Jim Bridger Unit 4, resource retirement and replacement alternatives were assumed to be available beginning January 2016 and January 2017, respectively. Natural-gas conversion alternatives were made available beginning March 2016 for Jim Bridger Unit 3 and March 2017 for Jim Bridger Unit 4, assuming coal-fueled operation would continue as long as possible and the work to complete the gas conversion could be accomplished over a two-month period.

Q. Did PacifiCorp's economic analysis consider how the power requirements from the SCR emission control systems might affect the net capacity of Jim Bridger Units 3 and 4?

A. Yes. The SCR emission control systems, once installed and operational, were assumed to reduce PacifiCorp's share of capacity of both Jim Bridger Unit 3 and Unit 4 by approximately 3.5 MW.

Q. Did your analysis account for changes in the fueling plan at the Jim Bridger plant between the SCR and natural-gas conversion or early-retirement scenarios?

A. Yes. If Jim Bridger Units 3 and 4 were to convert to natural gas or retire early, the coal fueling needs at the four-unit Jim Bridger plant would be reduced, which in turn, would influence mine plans and reclamation plans. Cash coal cost assumptions used in the SO model were based on non-capital-related costs to fuel the Jim Bridger plant, which included then-current third party coal prices and transportation costs from Black Butte coal as well as then-current cash operating cost forecasts for Bridger Coal Company (BCC) inclusive of final reclamation trust contributions. Under a two-unit coal operating plan, cash costs assumed closure of the Bridger Coal surface mine. Under a four-unit coal operating plan, cash costs assumed a two dragline operation at the surface mine. Cash coal cost assumptions for both the two-unit and four-unit coal operating plans used in the economic analysis are provided in Confidential Exhibit PAC/502.

Q. Please describe mine reclamation costs considered in PacifiCorp's economic analysis.

A. In 1989, the BCC owners established a final reclamation trust to fund actual final reclamation work. A sinking fund calculation is used to determine the appropriate final reclamation trust contribution rate and ensure sufficient funds exist in the trust to support final reclamation work once coal production ceases. Contributions to the final reclamation trust were included as part of the Jim Bridger plant cash coal costs through 2030, the study horizon used for the SO model analysis. Considering that reclamation costs continue beyond the 2030 study horizon, reclamation costs from 2031 through 2037 were included in the PVRR(d) calculations to capture differences in reclamation costs beyond the SO model study period. Confidential Exhibit PAC/503 summarizes reclamation costs for both the two-unit and four-unit coal operating plans used in the economic analysis.

Q. Did PacifiCorp consider differences in incremental mine capital costs between the two-unit and four-unit coal operating plans?

A. Yes. Over the period 2013 through 2030, average annual mine capital cost assumptions for a four-unit coal operating plan are higher than those in a two-unit coal operating plan. Confidential Exhibit PAC/504 shows annual mine capital cost assumptions used in the economic analysis for both the two-unit and four-unit coal operating plans.

Natural-Gas and CO_2 Price Scenarios

Q. Please explain why natural-gas and CO_2 price assumptions were important when analyzing the SCR emission control systems at Jim Bridger Units 3 and 4.

A. PacifiCorp evaluated early retirement and resource replacement or conversion of Jim Bridger Unit 3 and Unit 4 to natural gas as alternatives to SCR emission control systems. The assumed price for natural gas directly affects the cost for gas-fueled replacement resources in the case of an early retirement alternative or the fuel cost and replacement energy in the case of a gas conversion alternative. The price for natural gas is also a key factor in setting wholesale power prices. In this way, natural-gas prices disproportionately affect the value of energy net of operating costs from Jim Bridger Units 3 and 4 when operating as a coal-fueled resource versus the value of energy net of operating costs from a natural gas-fueled resource replacement alternative. Similarly, because of the relatively high level of carbon content in coal as compared to natural gas, higher CO_2 prices disproportionately affect the prospective cost of emissions between coal resources and natural gas as an alternative to the incremental investments required to continue operating Jim Bridger Units 3 and 4 as coal-fueled assets.

Q. Did PacifiCorp evaluate different assumptions for natural-gas prices and CO_2 prices in its analysis of the Jim Bridger Units 3 and 4 SCR systems?

A. Yes. In PacifiCorp's analysis of the SCR systems at Jim Bridger Units 3 and 4, eight different combinations of natural-gas and CO_2 price assumptions were analyzed as variations to the base case, which was tied to the September 2012 official forward price curve (OFPC). Table 1 summarizes the directional changes to base case assumptions among the eight scenarios. Two scenarios assume low and high natural-gas prices with base case CO_2 assumptions held constant; two scenarios assume low and high CO_2 price assumptions with the underlying base case natural-gas prices held constant; and four scenarios pair different combinations of natural-gas price and CO_2 price assumptions. In any scenario where the CO_2 assumption varies from that used in the base case, the underlying natural-gas price assumption was adjusted to account for an assumed natural-gas price response from changes in electric sector natural-gas demand.

Table 1. Natural-Gas and CO_2 Price Scenarios

Description	Natural-Gas Prices	CO_2 Prices
Base Case	September 2012 OFPC	\$16/ton in 2022 rising to \$23/ton by 2030
Low Gas, Base CO_2	Low	\$16/ton in 2022 rising to \$23/ton by 2030
High Gas, Base CO_2	High	\$16/ton in 2022 rising to \$23/ton by 2030
Base Gas, \$0 CO_2	Base case adjusted for price response	No CO_2 costs
Base Gas, High CO_2	Base case adjusted for price response	\$14/ton in 2020 rising to \$65/ton by 2030
Low Gas, High CO_2	Low case adjusted for price response	\$14/ton in 2020 rising to \$65/ton by 2030
High Gas, \$0 CO_2	High case adjusted for price response	No CO_2 costs
Low Gas, \$0 CO_2	Low case adjusted for price response	No CO_2 costs
High Gas, High CO_2	High case adjusted for price response	\$14/ton in 2020 rising to \$65/ton by 2030

Q. Why were natural-gas price assumptions adjusted in those scenarios where CO_2 price assumptions vary from the base case?

A. As I stated earlier, CO_2 prices disproportionately affect the prospective cost of emissions between coal resources and natural-gas alternatives. This is primarily driven by the relatively high level of carbon content in coal as compared to natural gas. With rising CO_2 prices, generating resources with lower CO_2 emissions, such as natural gas-fueled resources, can begin to displace coal-fueled generation, thereby increasing the demand for natural gas within the electric sector of the U.S. economy. Displacement of coal generation can also be influenced by low- or zero-emitting renewable generation sources; however, it was assumed that these low- or zero-emitting renewable resources would not entirely offset increased natural-gas demand. Conversely, with falling CO_2 prices (or a market that is absent CO_2 prices), there is no incremental emissions-based cost advantage for natural gas or renewable generation as compared to coal, and demand for natural gas in the electric sector of the U.S. economy could be slightly lower. It is assumed that any change in natural-gas demand must be balanced with a change in supply such that higher natural-gas demand yields an upward movement in price and lower natural-gas demand yields a downward movement in price.

Q. Did PacifiCorp only apply upward adjustments to natural-gas prices in response to changes in CO_2 price level?

A. No. The assumed interaction between natural-gas prices and CO_2 prices was applied on a bi-directional basis. That is, PacifiCorp not only assumed natural-gas prices rise in the presence of a CO_2 price (or with increased CO_2 price levels), but also incorporated downward natural-gas price pressures when CO_2 prices were removed or lowered.

Q. How did PacifiCorp choose its natural-gas and CO_2 price assumptions as used in the eight market price scenarios?

A. The range of low- and high-price assumptions were based upon the range of then current third-party expert forecasts and government agency price projections. Confidential Exhibit PAC/505 shows how the low and high price assumptions that were used in PacifiCorp's economic analysis compare to these third-party forecasts.

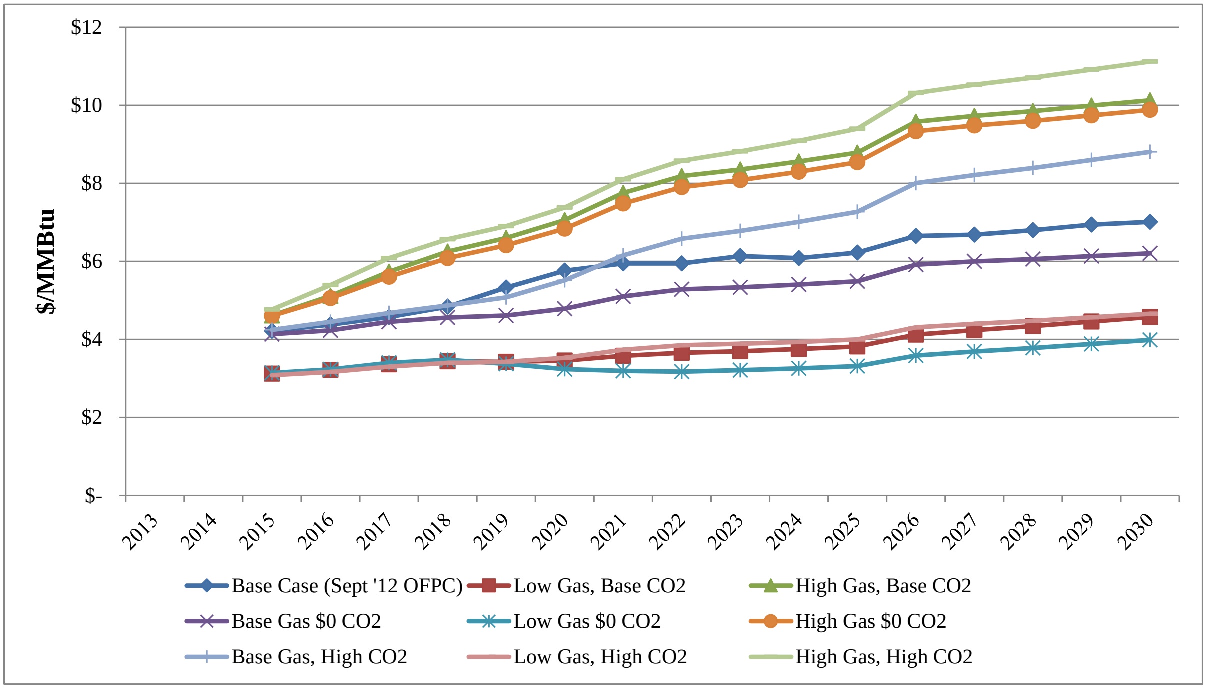
Low natural-gas price assumptions were derived from a third-party, low price scenario, which was characterized by strong and price-resilient shale gas supply growth and stagnant exports of liquefied natural gas out of the U.S. natural-gas market. The high natural-gas price assumptions were based on a blend of two, third-party price scenarios. This blending approach recognized that the most extreme high natural-gas price forecast was a strong outlier relative to price projections from other forecasters, and would have resulted in a high-price scenario that exceeds the highest of 47 natural-gas price forecasts in the U.S. Energy Information Administration's 2011 Annual Energy Outlook.[2]

Fundamental drivers to a high price scenario included constraints or disappointments in shale gas production, linkage to rising oil prices through substantial new demand in the transportation sector, and/or significant increases in

[2] The U.S. Energy Information Administration is the statistical and analytical agency within the U.S. Department of Energy. The highest natural-gas price forecast in the 2011 Annual Energy Outlook assumed that total unproved technically recoverable shale gas resources are reduced by 49 percent and that the estimated ultimate recovery per shale gas well is 50 percent lower than what was in their reference case.

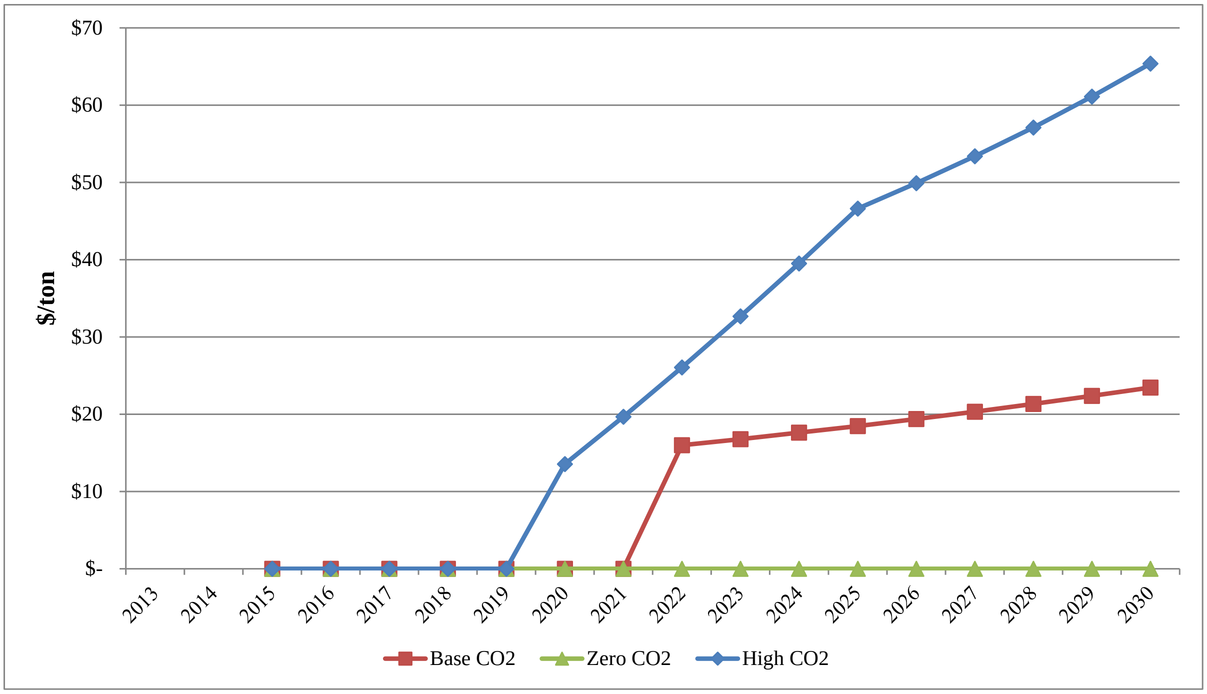
liquefied natural-gas exports out of the U.S. natural-gas market. Figure 1 shows the Henry Hub natural-gas price forecast among all market price scenarios considered in the economic analysis of the SCR emission control systems at Jim Bridger Units 3 and 4.

Figure 1. Henry Hub Natural-Gas Prices among All Scenarios



PacifiCorp assumed a zero CO_2 price for the low scenario recognizing that there had been limited activity in the CO_2 policy arena. For the high CO_2 price scenario, prices were assumed to begin in 2020, escalate rapidly through 2025 and reach $65/ton by 2030. The high CO_2 price scenario aligns with the then-current high CO_2 price forecast from a third-party source. Figure 2 shows the three CO_2 price assumptions used in the market-price scenarios supporting the economic analysis.

Figure 2. CO_2 Prices among All Scenarios



<u>Base-Case Results</u>

Q. Please describe the base-case results.

A. The optimized base-case simulation selected the SCR emission control systems at Jim Bridger Unit 3 and Jim Bridger Unit 4. The change-case simulation in which Jim Bridger Units 3 and 4 were not allowed to select SCR emission control systems showed that gas conversion was the next best, albeit higher cost, alternative to the installation of these SCR systems. The PVRR(d), as summarized in Exhibit PAC/506, shows that installation of SCR systems is $183 million lower cost than gas conversion.

Q. How were system costs impacted between the base-case simulation, where SCRs were installed on Jim Bridger Units 3 and 4, and the change-case simulation, where both units were converted to natural gas?

A. When SCR emission control systems were installed on Jim Bridger Units 3 and 4, total-company fuel costs are lower and net system balancing revenues are higher relative to a natural-gas conversion alternative that would significantly reduce generation levels from the two units. These total-company benefits more than offset the increased fixed costs associated with the capital for the SCR emission control systems, which were assumed to be approximately $372/kilowatts (kW) higher than gas conversion capital costs, and levelized annual operating and run-rate capital costs, which were assumed to be approximately $52/kW higher than projected gas conversion costs. On a total-company basis, the PVRR(d) of system variable costs was $775 million favorable to the SCR systems compliance alternative, which more than offset the $592 million increase to total-company fixed costs.[3]

Natural-Gas and CO_2 Price Scenario Results

Q. Please describe the results from the natural-gas and CO_2 price scenarios.

A. The natural-gas and CO_2 price scenario results showed that the investment in SCR emission control systems at Jim Bridger Unit 3 and Jim Bridger Unit 4 remained favorable to the next best, albeit higher cost natural-gas conversion alternative under all base and high natural-gas price scenarios at all assumed CO_2 price levels. In these

[3] System variable costs include fuel, net system balancing revenue, variable operations and maintenance (O&M) expenses, and CO_2 emissions expenses, as applicable. System fixed costs include incremental environmental controls costs, fixed O&M and run-rate capital expenses for existing and new resources, and changes to system demand-side management costs.

scenarios, the PVRR(d) ranges between $51 million favorable for the SCR systems (base gas, high CO_2) and $997 million favorable for the SCR systems (high gas, zero CO_2). The PVRR(d) results were unfavorable for the SCR systems only in those scenarios where then-current low natural-gas prices were assumed.

When low natural-gas price assumptions were paired with base CO_2 price assumptions, the nominal levelized price of natural gas at Opal[4] over the period 2016 to 2030 is $3.70 per million British thermal units (MMBtu) and the PVRR(d) is $285 million unfavorable for the SCR emission control systems required at Jim Bridger Units 3 and 4. In the low natural-gas, zero CO_2 price-policy scenario, the nominal levelized price of natural gas at Opal is $3.41 per MMBtu over the 2016 to 2030 time frame, and the PVRR(d) is $224 million unfavorable for the SCR emission control systems. When low natural-gas prices are paired with high CO_2 price assumptions, the nominal levelized price at Opal over the period 2016 to 2030 is $3.78 per MMBtu, and the PVRR(d) is $378 million unfavorable for the SCR emission control systems. The PVRR(d) results from the natural-gas and CO_2 price scenarios are summarized alongside the base case results in Exhibit PAC/506.

Q. How did the PVRR(d) results trend among the different updated natural-gas price assumptions?

A. The scenario results show that there is a strong trend between natural-gas price assumptions and the PVRR(d) benefit/cost associated with the SCRs required for continued operation of Jim Bridger Units 3 and 4 as coal-fueled assets. With higher natural-gas price assumptions, the SCR emission control systems are more favorable

[4] Opal is a natural-gas market hub located in Lincoln County, Wyoming.

as compared to the Jim Bridger Unit 3 and Unit 4 gas conversion alternative. Conversely, lower natural-gas prices improve the PVRR(d) results in favor of the gas conversion alternative. Lower natural-gas prices reduce the fuel cost of the gas conversion alternative, reduce the fuel cost of the other natural gas-fueled system resources that partially offset the generation lost from the coal-fueled Jim Bridger units, and reduce the opportunity cost of reduced off-system sales when Jim Bridger Units 3 and 4 operate as a gas-fueled generation assets.

Q. Could you infer from this trend how far natural-gas prices would have had to fall for gas conversion to have been favorable to installation of SCR systems at Jim Bridger Units 3 and 4?

A. Yes. Exhibit PAC/507 graphically displays the relationship between the nominal levelized natural-gas price at Opal over the period 2016 through 2030 and the PVRR(d) benefit/cost of continued coal operation of Jim Bridger Units 3 and 4 with installation of SCR emission control systems. To isolate the effects of CO_2 prices, which as I described earlier were assumed to elicit a natural-gas price response due to changes in demand for natural gas in the electric sector, the natural-gas price relationship with PVRR(d) results is shown for the natural-gas price scenarios in which the base case CO_2 price assumption was used. Based on this trend, levelized natural-gas prices over the period 2016 through 2030 would have to decrease by 15 percent, from $5.72 per MMBtu to $4.86 per MMBtu, to achieve a breakeven PVRR(d).

Q. How did the PVRR(d) results trend among the different CO_2 price assumptions?

A. Higher CO_2 price assumptions improve the PVRR(d) in favor of the gas conversion alternative, and lower CO_2 prices improve the economics of the SCR emission control systems. As with the trend described in the relationship between natural-gas prices and the PVRR(d) results, the relationship between CO_2 prices and the PVRR(d) benefit/cost of the SCR systems required at Jim Bridger Units 3 and 4 is intuitive. Because the CO_2 content of coal is nearly double the CO_2 content of natural gas, higher CO_2 prices lead to relatively lower cost of emissions for the gas conversion alternative and offset the costs related to any generation lost from the coal-fueled Jim Bridger Units 3 and 4 assets.

Q. What CO_2 price would be required to change the PVRR(d) results in favor of converting Jim Bridger Units 3 and 4 to natural gas?

A. Exhibit PAC/508 includes a graphical representation of the relationship between the nominal levelized CO_2 price over the period 2016 to 2030 and the PVRR(d) benefit/cost of installing the SCR emission control systems. To isolate the effects of fundamental shifts in the natural-gas price assumptions, the CO_2 price relationship with the PVRR(d) results is shown for the two CO_2 price scenarios that were paired with the same underlying base case natural-gas price assumption. Based upon the trend between PVRR(d) and nominal levelized CO_2 price assumptions, the levelized CO_2 prices over the period 2016 through 2030 would need to exceed $30 per ton, more than three times the base case nominal levelized CO_2 price assumption, to achieve a breakeven PVRR(d) for the Jim Bridger Unit 3 and Unit 4 SCR emission control systems.

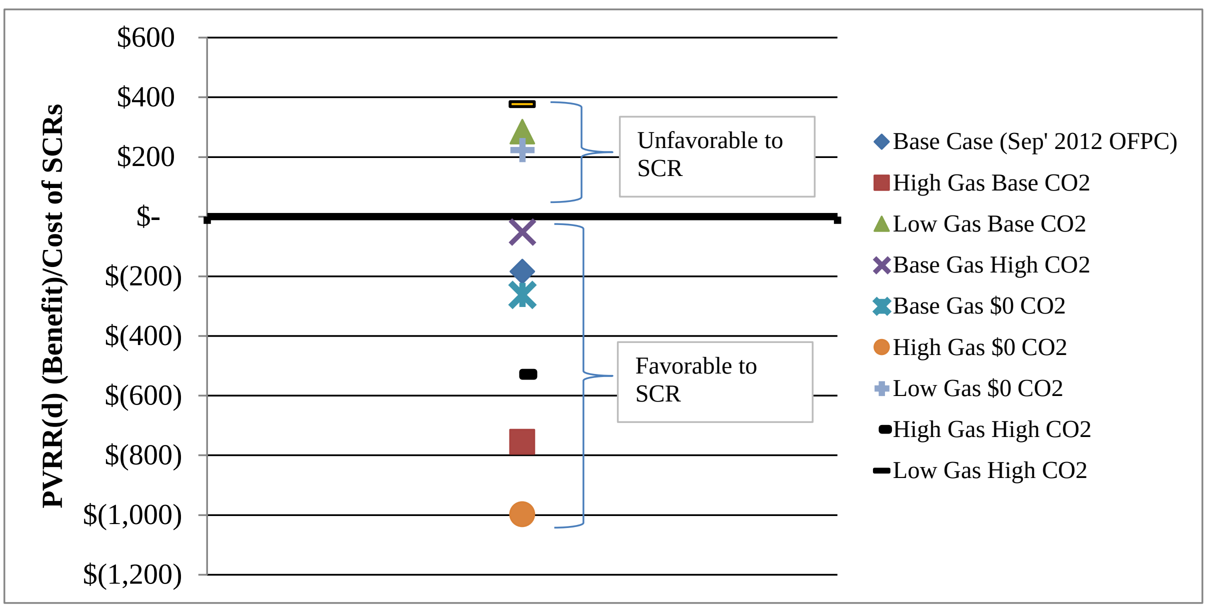
Q. How did PacifiCorp use the natural-gas and CO_2 price scenario results to inform its decision to install the Jim Bridger Unit 3 and Unit 4 SCR emission control systems?

A. PacifiCorp first reviewed the magnitude of the PVRR(d) results from the base case, which is defined by assumptions representing the company's best estimate of forward-looking assumptions at the time the analysis was completed. The base-case results provided an initial look at how favorable or unfavorable the SCR systems are in relation to the next best alternative and provided context when reviewing scenario results. The base case results summarized earlier in my testimony yield a PVRR(d) showing that the Jim Bridger Unit 3 and Unit 4 SCR systems would be $183 million lower cost than the natural-gas conversion alternative. This outcome also shows that when PacifiCorp's best estimate of forward-looking assumptions were used, there was a reasonably sized "cushion" in the PVRR(d) results allowing for some erosion of the favorable economics should long-term natural-gas prices or CO_2 prices change from what was assumed in the base case analysis. The natural-gas and CO_2 price scenarios were then used to quantify how sensitive the PVRR(d) results are to these key assumptions and provided a foundation for judging risk.

Q. Can you describe how PacifiCorp evaluated risk in the context of the results from the natural-gas and CO_2 price scenarios?

A. Yes. Figure 3 shows the distribution of PVRR(d) results for the base case and the eight natural-gas and CO_2 price scenarios. The figure shows that of the nine cases analyzed, six scenarios produce a PVRR(d) favorable to the SCR systems and the three scenarios with low gas price assumptions produce a PVRR(d) that was unfavorable to the SCR systems. The figure further illustrates the range of potential PVRR(d) outcomes among the scenarios analyzed. At one end of the spectrum, the PVRR(d) for the high gas, zero CO_2 scenario is $997 million favorable to the SCR systems. On the other end of the spectrum, the PVRR(d) for the low gas high CO_2 scenario is $378 million unfavorable to the Jim Bridger Unit 3 and Unit 4 SCR systems. Among the scenarios analyzed, the distribution of PVRR(d) outcomes indicate a disproportionate risk profile. While there is a possibility that the evolution of future natural-gas prices could have rendered the decision to invest in SCR systems to be higher cost than a gas conversion alternative, the cost impacts to customers of such an outcome were projected to be higher under a gas conversion alternative should future natural-gas prices rise relative to the base case.

Figure 3. Distribution of Scenario PVRR(d) Results

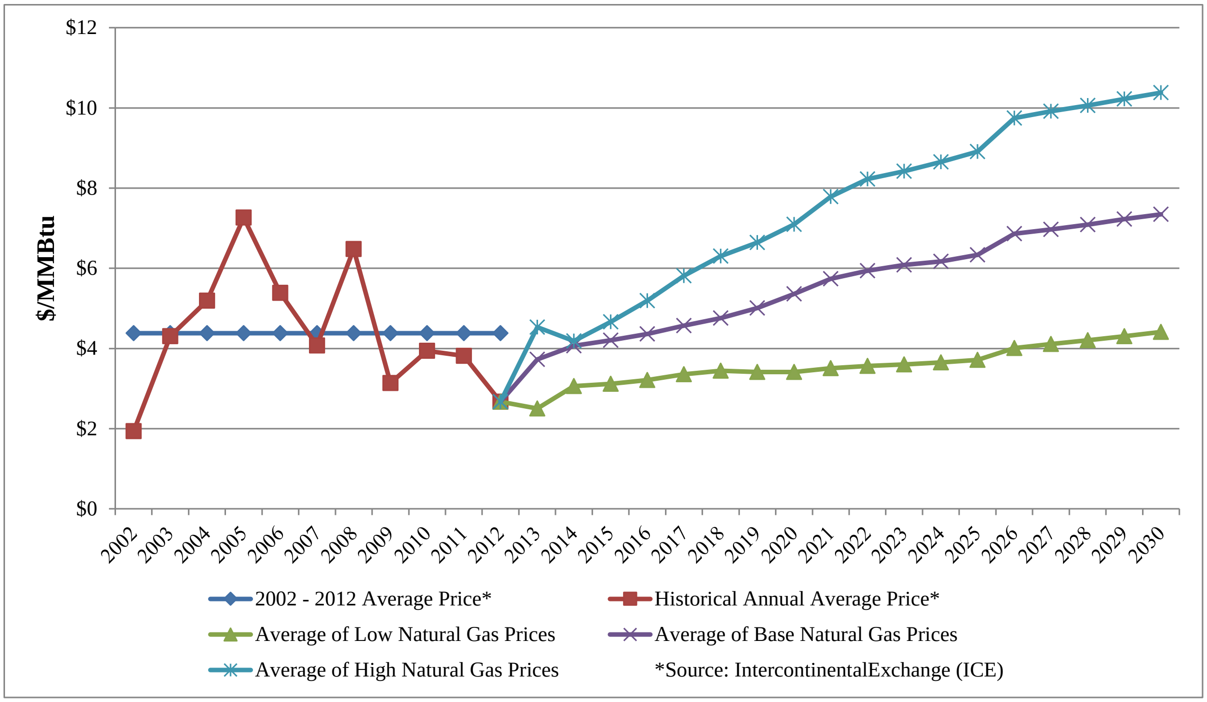


Q. Given the impact of low gas prices on the PVRR(d) results, how did you analyze the uncertainty around future natural-gas prices?

A. I compared the potential range of future natural-gas price scenarios in the context of historical natural-gas price levels. Figure 4 plots historical natural-gas prices alongside the average annual natural-gas price at Opal among the three low natural-gas price scenarios, the three base natural-gas price scenarios, and the three high natural-gas price scenarios.

Opal natural-gas prices in the low natural-gas price scenarios never reach 2002 to 2012 historical average prices over the course of the next 18 years. Among the low natural-gas price scenarios, the average annual price for natural gas at Opal over the period 2013 through 2030 is $3.59 per MMBtu, which is 18 percent below 2002–2012 historical price levels. Among the base natural-gas price scenarios, which are representative of the best estimate of forward-looking assumptions available at the time, the average annual price for Opal natural gas was $5.66 per MMBtu, or 29 percent above 2002–2012 historical price levels. Among the high natural-gas price scenarios, Opal natural-gas prices averaged $7.60 per MMBtu, representing a 73-percent increase relative to 2002-2012 historical prices.

Figure 4. Average Annual Natural-Gas Prices at Opal



Q. Did PacifiCorp consider the impact of changing market conditions on its Jim Bridger SCR analysis before issuing a full notice to proceed in December 2013?

A. Yes. PacifiCorp's economic analysis was designed to allow for rapid re-assessment of the PVRR(d) between the SCR and natural-gas conversion compliance alternatives with changing market conditions, complementing flexibility provisions that were negotiated in the engineering, procurement, and construction contract. PacifiCorp used this analysis when choosing installation of SCR emission control systems as the best compliance alternative in May 2013 and to assess how changes in market conditions affected customer benefits before issuing the full notice to proceed in December 2013.

Q. What were forward natural-gas prices at the time PacifiCorp committed to installing SCR systems at Jim Bridger Units 3 and 4?

A. Levelized natural-gas prices at Opal over the period 2016 through 2030 from the September 2013 OFPC, the most current OFPC at the time the full notice to proceed was issued, were $5.35 per MMBtu. Based upon the relationship described above, the predicted PVRR(d) with natural-gas prices applicable at the time PacifiCorp committed to install SCR systems at Jim Bridger Units 3 and 4 would have been approximately $130 million lower cost than the gas conversion alternative.

Q. Based on the analysis described above, was it in customers' best interest to pursue the installation of SCR emission control systems at Jim Bridger Units 3 and 4?

A. Yes. The economic analysis conducted by PacifiCorp clearly showed that installation of the SCR emission control systems was the least-cost, least-risk alternative.

<u>Early Retirement Sensitivity Analysis</u>

Q. Did PacifiCorp's base case and scenario analyses allow for early retirement as an alternative to the SCR emission control systems?

A. Yes. The PVRR(d) was calculated by taking the difference in system costs between two SO model simulations. One simulation assumed the SCR emission control systems would be installed and Jim Bridger Unit 3 and Unit 4 would continue operating as coal-fueled assets. The second simulation forced Jim Bridger Unit 3 and Unit 4 to stop operating as coal-fueled assets, allowing the model to choose among the most economical alternative, which includes gas conversion and early retirement. In all of the simulations forcing Jim Bridger Unit 3 and Unit 4 to stop operating as coal-fueled assets, the SO model chose gas conversion over early retirement when it is was assumed that the SCR emission control systems would not be installed.

Q. Did PacifiCorp perform an additional sensitivity that showed gas conversion would be a lower cost alternative to the SCR emission control systems than an early-retirement alternative?

A. Yes. For this sensitivity, in the case where Jim Bridger Unit 3 and Unit 4 were assumed to stop operating as coal-fueled assets, each unit was forced to retire (not allowing it to choose gas conversion) for purposes of calculating the PVRR(d).

Q. What are the results of this sensitivity analysis?

A. When Jim Bridger Unit 3 and Unit 4 were forced to retire early, the SO model added a 597 MW combined-cycle unit located in southern Utah in 2017.[5] As compared to an early retirement alternative, the PVRR(d) is $588 million in favor of the Jim Bridger Unit 3 and Unit 4 SCR emission control systems. The sensitivity also shows that gas conversion, while unfavorable to the SCR systems, has a PVRR(d) that is $405 million favorable to early retirement.

IV. WIND REPOWERING

<u>2017 Integrated Resource Plan</u>

Q. Did PacifiCorp analyze wind repowering in its 2017 IRP?

A. Yes. The preferred portfolio in the 2017 IRP, representing PacifiCorp's least-cost, least-risk plan to reliably meet customer demand over a 20-year planning period, includes repowering of 905 MW of existing wind resource capacity located in

[5]Incremental front office transactions are also included in the portfolio when Jim Bridger Unit 3 and 4 are forced to retire early.

Wyoming, Washington, and Oregon. As discussed later in my testimony, PacifiCorp has since expanded the wind repowering scope to include its Goodnoe Hills wind facility. With the addition of Goodnoe Hills, PacifiCorp is planning to repower approximately 999 MW of existing wind capacity.

Q. What led PacifiCorp to evaluate the wind repowering opportunity in its 2017 IRP?

A. As explained in Mr. Timothy J. Hemstreet's testimony (Exhibit PAC/600), PacifiCorp purchased safe-harbor equipment from General Electric International, Inc., and Vestas American Wind Technology, Inc., in December 2016. Consistent with Internal Revenue Service (IRS) guidance, these equipment purchases, totaling $77.8 million, secured an option for PacifiCorp to repower its fleet of owned wind resources, thereby qualifying them for the full value of federal PTCs.

Wind repowering presents an opportunity to deliver several different types of benefits for customers. First, federal PTCs will apply to 10 additional years of generation from each repowered wind resource. The current value of federal PTCs, which is adjusted annually for inflation by the IRS, is $24/megawatt-hour (MWh). At a federal and state effective tax rate of 24.587 percent, the current PTC equates to a $31.82/MWh reduction in revenue requirement that can be passed through to customers.

Second, existing wind resources will be upgraded with modern technology, which improves efficiency and increases energy output. The additional energy output from these zero-fuel-cost assets provides incremental NPC benefits for customers.

Third, repowering a wind resource, which replaces the mechanical equipment of an existing wind facility, resets the usable life of the asset (currently 30 years), thereby extending and increasing NPC benefits over the period in which the repowered wind resource would have otherwise been retired from service.

Finally, the turbine-supply contracts for repowering will include a two-year warranty on the new equipment, which will avoid capital expenditures that would otherwise be needed to replace or refurbish existing equipment. Moreover, PacifiCorp anticipates that new, modern equipment will have reduced failure rates. Further, before installing the new equipment, PacifiCorp can avoid capital replacement costs for component failures on the existing equipment. This cost savings will be partially offset by lost energy output for specific wind turbines from the time that component failures occur through the time that the new equipment is installed.

After executing its safe-harbor equipment purchase in December 2016, PacifiCorp developed a wind repowering sensitivity in the first quarter of 2017, for consideration in its 2017 IRP, to evaluate potential net customer benefits.

Q. What wind resources did PacifiCorp include in the wind repowering sensitivity presented in its 2017 IRP?

A. PacifiCorp assumed repowering 905 MW of existing wind resource capacity in the 2017 IRP. Of the 905 MW, approximately 594 MW of this capacity are located in Wyoming (Glenrock, Rolling Hills, Seven Mile Hill, High Plans, McFadden Ridge, and Dunlap), approximately 101 MW are located in Oregon (Leaning Juniper), and approximately 210 MW are located in Washington (Marengo). PacifiCorp has since expanded its economic analysis to include Goodnoe Hills, which is located in Washington.

Q. What were the results of the wind repowering sensitivity presented in PacifiCorp's 2017 IRP?

A. The 2017 IRP wind repowering sensitivity showed significant net customer benefits across a range of assumptions related to forward market prices and possible federal CO_2 policy.

Q. Did the wind repowering sensitivity influence selection of the preferred portfolio in the 2017 IRP?

A. Yes. The wind repowering sensitivity included in the 2017 IRP showed significant net customer benefits by lowering the projected system present-value revenue requirement (PVRR) relative to other resource portfolio options. Consequently, wind repowering was included in the 2017 IRP preferred portfolio, which represents PacifiCorp's plan to deliver reliable and reasonably priced service with manageable risk for customers through specific action items.

Q. Did PacifiCorp include a wind repowering action item 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:

> PacifiCorp will implement the wind repowering project, taking advantage of safe-harbor wind-turbine-generator equipment purchase agreements executed in December 2016.

- Continue to refine and update economic analysis of plant-specific wind repowering opportunities that maximize customer benefits before issuing the notice to proceed.

- By September 2017, complete technical and economic analysis of other potential repowering opportunities at PacifiCorp wind plants not studied in the 2017 IRP (i.e., Foote Creek I and Goodnoe Hills).

- Pursue regulatory review and approval as necessary.

- By May 2018, issue the engineering, procurement and construction (EPC) notice to proceed to begin implementing wind repowering for specific projects consistent with updated financial analysis.

- By December 31, 2020, complete installation of wind repowering equipment on all identified projects.[6]

Q. Please summarize PacifiCorp's progress with this action item.

A. PacifiCorp refined and updated its economic analysis of plant-specific wind repowering opportunities, and is now including Goodnoe Hills in the wind repowering project. The economic analysis has also been updated to reflect more current assumptions resulting from recent changes in the federal tax rate for corporations. The rest of my testimony presents and explains this economic analysis. Mr. Hemstreet explains that PacifiCorp continues to evaluate repowering of the Foote Creek facility in Wyoming, but due to differences in project scope for this older-vintage facility, Foote Creek was not included in the economic analysis of the wind repowering project at this time. Mr. Hemstreet also discusses the need to execute contracts by [redacted] and addresses the construction schedule.

[6] PacifiCorp 2017 Integrated Resource Plan, Volume I at 16 (Apr. 4, 2017).

System Modeling Methodology

Q. Please summarize the methodology PacifiCorp used in its system analysis of the wind repowering project.

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 wind repowering project. These modeling tools calculate a 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 wind repowering project and the other simulation excludes the wind repowering project. Customers are expected to realize benefits when the system PVRR with wind repowering is lower than the system PVRR without repowering. Conversely, customers would experience increased costs if the system PVRR with wind repowering were higher than the system PVRR without wind repowering.

Q. What modeling tools did PacifiCorp use to perform its system analysis of the wind repowering project?

A. PacifiCorp used the 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 wind repowering.

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 O&M, 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, 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 the PaR model reflects a distribution of system variable costs, including variable costs associated with existing contracts, wholesale-market purchases and sales, fuel costs, variable O&M 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 O&M 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 as discussed earlier in my testimony, the SO model has been used to evaluate installation of emissions control systems. These models will also be used to evaluate bids in PacifiCorp's recent 2017R RFP, issued to solicit bids for new wind resources, and in PacifiCorp's recent 2017S RFP, issued to solicit bids for new solar resources.

Q. Are the SO model and PaR the appropriate tools for analyzing the wind repowering opportunity?

A. Yes. The SO model and PaR are the appropriate modeling tools when evaluating significant capital investments 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 wind repowering project. PaR provides additional granularity on how wind repowering is 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 wind repowering opportunity 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 wind repowering?

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 repowering. 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 wind repowering analysis, the stochastic-mean PVRR represents the expected level of system costs from cases with and without repowering. The risk-adjusted PVRR is used to assess whether wind repowering causes a disproportionate increase to system variable costs under low-probability, high-cost system conditions.

Q. Please describe how the effective combined federal and state income tax rate assumption is applied in the SO model and the PaR in the economic analysis.

A. The effective combined federal and state income tax rate affects PacifiCorp's post-tax weighted average cost of capital, which is used as the discount rate in the SO model and PaR. With the recent changes in tax law, PacifiCorp's discount rate is 6.91 percent.

The income tax rate also affects the capital revenue requirement for all new resource options available for selection in the SO model. Capital revenue requirement is levelized in the SO and PaR models to avoid potential distortions in the economic analysis of capital-intensive assets that have different lives and in-service dates. This is achieved through annual capital recovery factors, which are expressed as a percentage of the initial capital investment for any given resource alternative in any given year. Capital recovery factors, which are based on the revenue requirement for specific types of assets, are differentiated by each asset's assumed life, book-depreciation rates, and tax-depreciation rates. Because capital revenue requirement accounts for the impact of income taxes on rate-based assets, the capital recovery factors applied to new resource costs in the SO model were reflected for each system simulation.

Finally, the income tax rate affects the tax gross-up of all PTC-eligible resources. The current value of federal PTCs is $24/MWh, which equates to a $31.82/MWh reduction in revenue requirement assuming an effective combined federal and state income tax rate of 24.587 percent. The impact of the income tax rate assumptions were applied to all PTC-eligible resource alternatives available in the SO model.

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

A. Yes. In addition to assessing stochastic system cost risk, PacifiCorp analyzed the wind-repowering project 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 repowering, 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.

Q. How did PacifiCorp assess which wind facilities to include in the scope of the wind repowering project in this application?

A. PacifiCorp completed a series of SO model and PaR studies to determine how the system PVRR changes when a specific wind facility is added or removed from the scope of the wind repowering project. This project-by-project analysis was performed by running one SO model simulation that included the full scope of the wind repowering project and then 12 separate SO model simulations where one of the repowered wind facilities is assumed to be excluded from the scope of the wind repowering project. The total system cost from the SO model simulation where all facilities are repowered and from the SO model simulation where one facility is removed from scope is used to calculate the marginal PVRR(d) for each wind facility. Using the resource portfolio from the SO model simulations, this same approach was used to calculate the PVRR(d) for each wind facility using projected system costs from PaR.

Q. What key assumptions did PacifiCorp update since analyzing the wind repowering project in its 2017 IRP?

A. Beyond the price-policy assumptions used to analyze a range of NPC-related benefits, the updated wind repowering analysis reflects updated assumptions for up-front capital costs, run-rate operating costs, and energy output for both the existing and repowered wind facilities. PacifiCorp's analysis assumes an up-front capital investment totaling approximately $1.101 billion with a 25.7 percent average increase in annual energy output (738 gigawatt-hours (GWh) per year). The cost and performance assumptions for the wind facilities studied in this updated economic analysis are summarized in Confidential Exhibit PAC/509.

Q. Did PacifiCorp analyze potential energy imbalance market (EIM) benefits in its wind repowering analysis?

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 wind repowering analysis 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 wind repowering project; however, this increased connectivity provides the opportunity to move low-cost incremental energy out of transmission-constrained areas of Wyoming.

Q. How did PacifiCorp account for the unrecovered investments in the original equipment that will be replaced with new equipment?

A. The economic analysis assumes that PacifiCorp will fully recover the unrecovered investment in the original equipment and earn its authorized rate of return on the unrecovered balance over the remainder of the original 30-year depreciable life of each repowered facility. Ms. Shelley E. McCoy (Exhibit PAC/1100) describes PacifiCorp's proposed accounting treatment for the replaced equipment.

Q. Did PacifiCorp assume any salvage value for the equipment that will be replaced with repowering?

A. No. But any salvage value for the existing equipment would decrease the unrecovered investment and increase customer benefits.

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-annual revenue requirement due to the wind repowering project?

A. Yes. The system PVRR from the SO model and PaR is 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 (*e.g.*, NPC, fixed O&M) and levelized revenue requirement for capital expenditures. To estimate the annual revenue-requirement impacts of repowering, project capital costs need to be considered in nominal terms (*i.e.*, not levelized).

Q. Why is the capital revenue requirement used in the calculation of the system PVRR from the 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 on 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 wind repowering project?

A. In the models that exclude repowered wind, the annual stream of costs for wind facilities that are within the wind repowering scope, including levelized capital, are removed from the annual stream of costs used to calculate the stochastic-mean system PVRR. Similarly, in the simulation that includes repowered wind, the annual stream of costs for repowered wind facilities, including levelized capital and PTCs, 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 wind facilities that are within the wind repowering scope, represents the net system benefit caused by the wind repowering project.

These data are disaggregated to isolate the estimated annual NPC benefits, other non-NPC variable-cost benefits (*i.e.*, variable O&M 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 fixed costs for those wind facilities included in the wind repowering scope, including nominal capital revenue requirement and PTCs, are added back in with the annual system net benefits caused by wind repowering.

Q. Over what time frame did PacifiCorp estimate the change in annual revenue requirement due to the wind repowering project?

A. The change in annual revenue requirement was estimated through 2050. This captures the full 30-year life of the new equipment installed on repowered wind facilities.

Q. How did PacifiCorp calculate the net annual benefits caused by wind repowering 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 wind repowering over the 2028-through-2036 time frame, expressed in dollars-per-MWh of incremental energy output from wind repowering, were used to estimate the change in system net benefits from 2037 through 2050. This calculation was performed in several steps.

First, the net system benefits caused by wind repowering were divided by the change in incremental energy expected from the wind repowering project, as modeled in PaR over the 2028-through-2036 time frame. Next, the net system benefits per MWh of incremental energy from the repowered wind 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 repowered wind projects over the 2037-through-2050 time frame were then multiplied by the change in incremental energy output from repowered wind 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 wind repowering analysis 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 many repowered wind resources are located, is reduced. The incremental energy output from repowered wind resources provides more system benefits when not constrained by transmission limitations. Consequently, the net system benefits caused by wind repowering 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 wind repowering project using its estimate of annual revenue-requirement impacts projected out through 2050?

A. Yes.

Q. Does the PVRR(d) calculated from estimated annual revenue requirement through 2050 capture wind repowering benefits not included in the PVRR(d) calculated from the 20-year forecast coming out of the SO model and PaR?

A. Yes. The PVRR(d) calculated off of estimated annual revenue requirement extended out through 2050 captures the significant increase in projected wind energy output beyond the 20-year forecast period.

Q. Why is there a significant increase in projected wind energy output beyond the 20-year forecast period ending 2036?

A. 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, 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 change in wind energy output reflects the incremental energy production that results from installing modern equipment on repowered wind assets. Beyond the 2036-through-2040 time frame, 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.

<u>Price-Policy Scenarios</u>

Q. Please explain why price-policy scenarios are important when analyzing the wind repowering project.

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 wind repowering. 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 NPC benefits, non-NPC variable cost benefits, and system fixed-cost benefits of wind repowering. Because wholesale-power prices and CO_2 policy outcomes are both uncertain and important drivers to the wind repowering analysis, PacifiCorp studied the economics of the wind repowering project under a range of different price-policy scenarios.

Q. What price-policy scenarios did PacifiCorp use in its wind repowering analysis?

A. PacifiCorp analyzed the wind repowering project 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 wind repowering analysis 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 recognizing that it is possible that future CO_2 policies targeting electric-sector emissions could be adopted and impose incremental costs to drive emission 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.

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

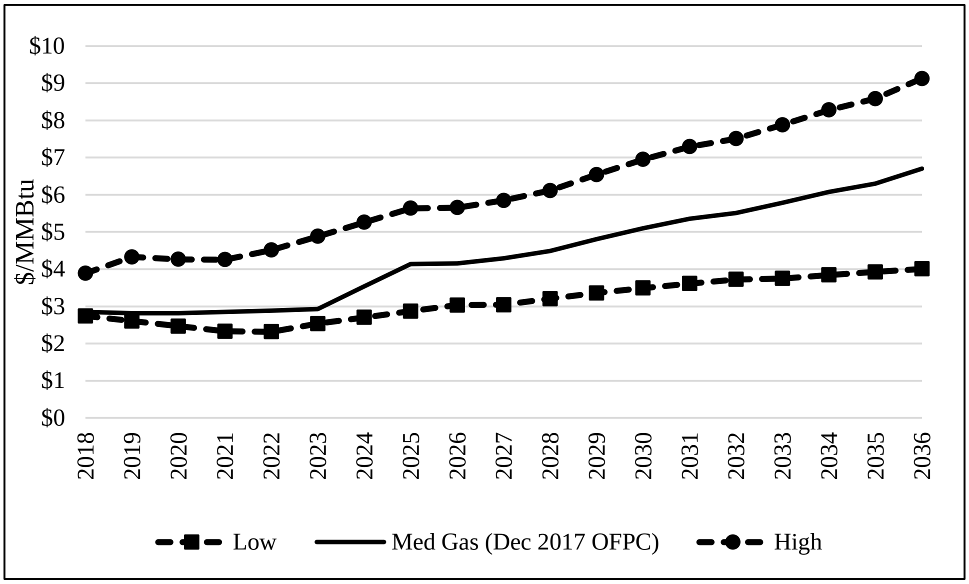
A. The medium-natural-gas price assumptions that are paired with zero CO_2 prices reflect natural-gas prices from PacifiCorp's OFPC dated December 29, 2017. This

OFPC uses observed forward market prices as of December 29, 2017, for 72 months, followed by a 12-month transition to natural-gas prices based on a forecast developed by [redacted]. The medium-, low-, 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. Confidential Exhibit PAC/510 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 wind repowering project.

The low-natural-gas price assumption was derived from a low-price scenario developed by [redacted]. The medium-natural-gas price assumption, which is used beyond month 84 in the December 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] that is characterized by exaggerated boom-bust cycles (cyclical periods of high prices and low prices). PacifiCorp smoothed the boom-bust cycle in this third party's high-price scenario because the specific timing of these cycles are extremely difficult to project with reasonable accuracy.

Figure 5 shows Henry Hub natural-gas price assumptions from the December 2017 OFPC, low-, and high-natural-gas price scenarios.

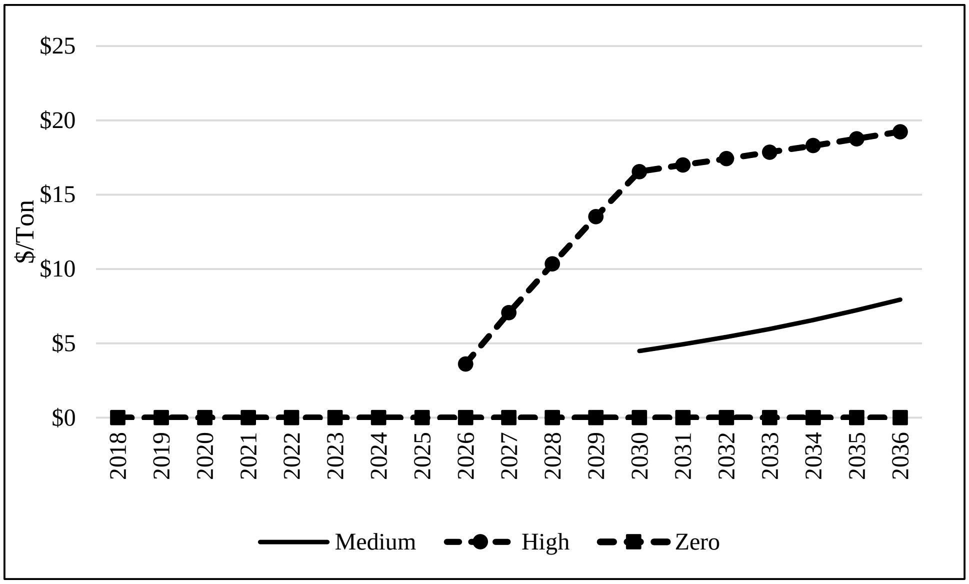
Figure 5. Nominal Natural-Gas Price Scenarios



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]. 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 6 shows the CO_2 price assumptions used to analyze the wind repowering project.

Figure 6. Nominal CO_2 Price Scenarios



<u>Project-by-Project Results</u>

Q. What price-policy scenarios were used in the project-by-project analysis?

A. PacifiCorp used two price-policy scenarios—the low natural-gas and zero CO_2 price-policy scenario and the medium natural-gas and medium CO_2 price-policy scenario. Based on the results of these two price-policy scenarios, the company determined which individual projects are expected to provide net customer benefits, and then these projects were analyzed under all price-policy scenarios.

Q. Please summarize the project-by-project PVRR(d) results calculated from the SO model and PaR through 2036 when assuming medium natural-gas and medium CO_2 price-policy assumptions.

A. Table 2 summarizes the PVRR(d) results for each wind facility within the scope of the wind repowering project. The PVRR(d) between cases with and without wind repowering are shown for each wind facility based on system modeling results from the SO model and PaR, before accounting for the substantial increase in incremental energy beyond the 2036 time frame. When applying medium natural-gas and medium CO_2 price-policy assumptions, benefits from repowering the Leaning Juniper wind facility are equal to costs. All other wind facilities are projected to deliver net benefits.

Table 2. Project-by-Project SO Model and PaR PVRR(d) (Benefit)/Cost of Wind Repowering with Medium Natural-Gas and Medium CO_2 Price-Policy Assumptions ($ million)

Wind Facility	SO Model PVRR(d)	PaR Stochastic-Mean PVRR(d)	PaR Risk-Adjusted PVRR(d)
Glenrock 1	($25)	($21)	($23)
Glenrock 3	($8)	($7)	($7)
Seven Mile Hill 1	($33)	($28)	($29)
Seven Mile Hill 2	($7)	($7)	($7)
High Plains	($17)	($13)	($13)
McFadden Ridge	($5)	($4)	($4)
Dunlap Ranch	($30)	($26)	($27)
Rolling Hills	($12)	($9)	($10)
Leaning Juniper	($0)	($0)	($0)
Marengo 1	($35)	($33)	($34)
Marengo 2	($15)	($14)	($15)
Goodnoe Hills	($18)	($18)	($19)
Total	($205)	($180)	($189)

Q. Please summarize the project-by-project PVRR(d) results calculated from the SO model and PaR through 2036 when assuming low natural-gas and zero CO_2 price-policy assumptions.

A. Table 3 summarizes the PVRR(d) results for each wind facility within the scope of the wind repowering project. The PVRR(d) between cases with and without wind repowering are shown for each wind facility based on system modeling results from the SO model and PaR, before accounting for the substantial increase in incremental energy beyond the 2036 time frame. When applying low natural-gas and zero CO_2 price-policy assumptions, costs from repowering the Leaning Juniper wind facility are slightly higher than the benefits. All other wind facilities are projected to deliver net benefits.

Table 3. Project-by-Project SO Model and PaR PVRR(d) (Benefit)/Cost of Wind Repowering with Low Natural-Gas and Zero CO_2 Price-Policy Assumptions ($ million)

Wind Facility	SO Model PVRR(d)	PaR Stochastic-Mean PVRR(d)	PaR Risk-Adjusted PVRR(d)
Glenrock 1	($21)	($21)	($22)
Glenrock 3	($7)	($6)	($6)
Seven Mile Hill 1	($28)	($28)	($29)
Seven Mile Hill 2	($6)	($6)	($6)
High Plains	($12)	($9)	($10)
McFadden Ridge	($4)	($3)	($3)
Dunlap Ranch	($25)	($22)	($24)
Rolling Hills	($9)	($7)	($7)
Leaning Juniper	$6	$3	$4
Marengo 1	($27)	($25)	($26)
Marengo 2	($11)	($10)	($11)
Goodnoe Hills	($13)	($15)	($15)
Total	($157)	($149)	($156)

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

A. Table 4 summarizes the PVRR(d) results for each wind facility calculated off of the change in annual nominal revenue requirement through 2050 for both price-policy scenarios. Unlike the results summarized in Tables 2 and 3, these results account for the substantial increase in incremental energy beyond the 2036 time frame. Each of the wind facilities within the scope of the proposed repowering project show net benefits with repowering under the medium natural-gas and medium CO_2 price-policy scenario and all facilities show net benefits under the low-natural-gas and zero CO_2 price-policy scenario, except for the Leaning Juniper wind facility, where the benefits are equal to the costs.

Table 4. Project-by-Project Nominal Revenue Requirement PVRR(d) (Benefit)/Cost of Wind Repowering ($ million)

Wind Facility	Medium Natural-Gas and Medium CO_2	Low Natural-Gas and Zero CO_2
Glenrock 1	($33)	($33)
Glenrock 3	($11)	($6)
Seven Mile Hill 1	($41)	($40)
Seven Mile Hill 2	($10)	($6)
High Plains	($22)	($6)
McFadden Ridge	($7)	($2)
Dunlap Ranch	($39)	($23)
Rolling Hills	($15)	($5)
Leaning Juniper	($8)	($0)
Marengo 1	($50)	($22)
Marengo 2	($20)	($7)
Goodnoe Hills	($26)	($19)
Total	($282)	($170)

Q. The project-by-project results vary by wind facility, and some wind facilities appear to show relatively small PVRR(d) benefits. Have you calculated the net benefits of the wind repowering project taking into account the size of each wind facility?

A. Yes. The magnitude of the PVRR(d) results must be considered in relation to the specific attributes of the repowered wind facility, including the size of the facility, the expected cost to repower the facility, and the level of annual energy output expected after the new equipment is installed. For example, the PVRR(d) for McFadden Ridge shows a $7 million benefit when repowered (using medium natural-gas and medium CO_2 price-policy assumptions)—the lowest PVRR(d) among all of the project-by-project results. The PVRR(d) benefit for McFadden Ridge is approximately 14 percent of the $50 million benefit for Marengo I, which yields the highest PVRR(d) among all of the project-by-project results. However, the current capacity of McFadden Ridge (28.5 MW) is approximately 20 percent of the current capacity of Marengo I (140.4 MW). Similarly, the expected energy output after repowering for McFadden Ridge (approximately 117 GWh per year) is approximately 24 percent of the expected energy output after repowering for Marengo I (approximately 488 GWh per year).

A reasonable metric to evaluate the relative benefits among the wind facilities that captures the specific attributes of each facility is the nominal levelized net benefit per incremental MWh expected after the facility is repowered. This metric captures the specific repowering cost for each facility net of the specific benefits of each facility per incremental MWh of energy expected after the facility is repowered. Table 5 shows the nominal levelized net benefit of repowering per MWh of expected incremental energy output after repowering for each wind facility. When using medium natural-gas and medium CO_2 price-policy assumptions, the table shows the Seven Mile Hill II facility produces the largest net benefit per incremental MWh

($36/MWh), and Leaning Juniper produces the smallest net benefit per incremental MWh ($7/MWh).

Table 5. Nominal Levelized Net Benefit per MWh of Incremental Energy Output after Repowering ($/MWh)

Wind Facility	Medium Natural-Gas and Medium CO_2	Low Natural-Gas and Zero CO_2
Glenrock 1	$29/MWh	$29/MWh
Glenrock 3	$28/MWh	$16/MWh
Seven Mile Hill 1	$30/MWh	$29/MWh
Seven Mile Hill 2	$36/MWh	$23/MWh
High Plains	$17/MWh	$5/MWh
McFadden Ridge	$17/MWh	$5/MWh
Dunlap Ranch	$28/MWh	$17/MWh
Rolling Hills	$19/MWh	$7/MWh
Leaning Juniper	$7/MWh	$0/MWh
Marengo 1	$25/MWh	$11/MWh
Marengo 2	$21/MWh	$8/MWh
Goodnoe Hills	$26/MWh	$18/MWh
Weighted Average	$25/MWh	$16/MWh

Q. Is there an upside to the project-by-project PVRR(d) results?

A. Yes. The project-by-project results do not reflect the potential value of RECs that will be generated by the incremental energy output from each facility. For instance, as applied to the Leaning Juniper project discussed above, present-value net customer benefits would increase by approximately $1.1 million (approximately 14 percent of the PVRR(d) benefits under the medium natural-gas and medium CO_2 price-policy scenario as shown in Table 4) for every dollar assigned to the incremental RECs that will be generated from this facility. Moreover, the CO_2 price assumptions used in the economic analysis were inadvertently modeled in 2012 real dollars instead of nominal dollars. Consequently, the PVRR(d) net benefits in the medium natural-gas, medium CO_2 price-policy scenario are conservative.

Q. Based on these results, has the company decided against repowering any of the 12 facilities that were originally included in the repowering project?

A. No. The project-by-project analysis demonstrates that the proposed scope of the wind repowering project, which includes repowering 12 wind facilities with a current capacity totaling just over 999 MW is appropriate and will maximize customer benefits.

<u>System Modeling Price-Policy Results</u>

Q. Please summarize the PVRR(d) results for the full scope of the wind repowering project as calculated from the SO model and PaR through 2036 among all nine price-policy scenarios.

A. Table 6 summarizes the PVRR(d) results for each price-policy scenario for the full scope of the wind repowering project. The PVRR(d) between cases with and without the repowering project, are shown for the SO model and for PaR, which was used to calculate both the stochastic-mean PVRR(d) and the risk-adjusted PVRR(d). The data used to calculate the PVRR(d) results shown in the table are provided as Exhibit PAC/511.

**Table 6. SO Model and PaR PVRR(d)
(Benefit)/Cost of the Wind Repowering Projects ($ million)**

Price-Policy Scenario	SO Model PVRR(d)	PaR Stochastic-Mean PVRR(d)	PaR Risk-Adjusted PVRR(d)
Low Gas, Zero CO_2	($159)	($141)	($148)
Low Gas, Medium CO_2	($158)	($139)	($146)
Low Gas, High CO_2	($183)	($165)	($173)
Medium Gas, Zero CO_2	($201)	($171)	($180)
Medium Gas, Medium CO_2	($204)	($180)	($189)
Medium Gas, High CO_2	($215)	($193)	($203)
High Gas, Zero CO_2	($257)	($234)	($246)
High Gas, Medium CO_2	($260)	($248)	($260)
High Gas, High CO_2	($273)	($240)	($252)

Over a 20-year period, the wind repowering project reduces customer costs in all nine price-policy scenarios. This outcome is consistent in both the SO model and PaR results. Under the central price-policy scenario, assuming medium natural-gas prices and medium CO_2 prices, the PVRR(d) net benefits range between $180 million, when derived from PaR stochastic-mean results, and $204 million, when derived from SO model results.

Q. What trends do you observe in the modeling results across the different price-policy scenarios?

A. Projected system net benefits increase with higher-natural-gas price assumptions, and similarly, generally increase with higher CO_2 price assumptions. Conversely, system net benefits generally decline when low natural-gas prices and low CO_2 prices are assumed. This trend holds true when looking at the results from the two simulations used to calculate the PVRR(d) for all nine of the price-policy scenarios. Importantly, both models show that the net benefits from the wind repowering project are robust across a range of price-policy assumptions.

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

A. Yes. The PVRR(d) results presented in Table 6 do not reflect the potential value of RECs generated by the incremental energy output from the repowered facilities. Customer benefits for all price-policy scenarios would improve by approximately $6 million for every dollar assigned to the incremental RECs that will be generated from the repowered facilities through 2036. Quantifying the potential upside associated with incremental REC revenues is intended to simply communicate that the net benefits from the repowering project would improve if the incremental RECs can be monetized in the market or if those RECs are used to reduce incremental costs associated with meeting state renewable portfolio standard targets.

Q. Is there additional upside to the net benefits shown in Table 6?

A. Yes. As noted earlier in my testimony, the CO_2 price assumptions used in the economic analysis were inadvertently modeled in 2012 real dollars instead of nominal dollars. Consequently, the PVRR(d) net benefits in the six price-policy scenarios that use medium and high CO_2 price assumptions are conservative.

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

A. The two models assess the system impacts of the wind repowering project 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. In evaluating differences in annual system costs between the two models, PaR's ability to better simulate system dispatch relative to the SO model results in lower benefits from repowering being reported from PaR.

Q. Does one of these two models provide a better assessment of the wind repowering project relative to the other?

A. No. The two models are simply different, and both are useful in establishing a range of wind repowering benefits through the 20-year forecast period. Importantly, the PVRR(d) results from both models show customer benefits across the same set of 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 wind repowering benefits 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 show slightly greater net benefits than those calculated from the stochastic-mean PVRR(d) results. This indicates that the wind repowering project, which provides incremental zero-fuel-cost energy, provides incremental benefits in reducing the impact 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.

<u>Annual Revenue Requirement Price-Policy Results</u>

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

A. Table 7 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 PAC/512.

Table 7. Nominal Revenue Requirement PVRR(d) (Benefit)/Cost of Wind Repowering ($ million)

Price-Policy Scenario	Annual Revenue Requirement PVRR(d)
Low Gas, Zero CO_2	($127)
Low Gas, Medium CO_2	($121)
Low Gas, High CO_2	($223)
Medium Gas, Zero CO_2	($224)
Medium Gas, Medium CO_2	($273)
Medium Gas, High CO_2	($321)
High Gas, Zero CO_2	($389)
High Gas, Medium CO_2	($386)
High Gas, High CO_2	($466)

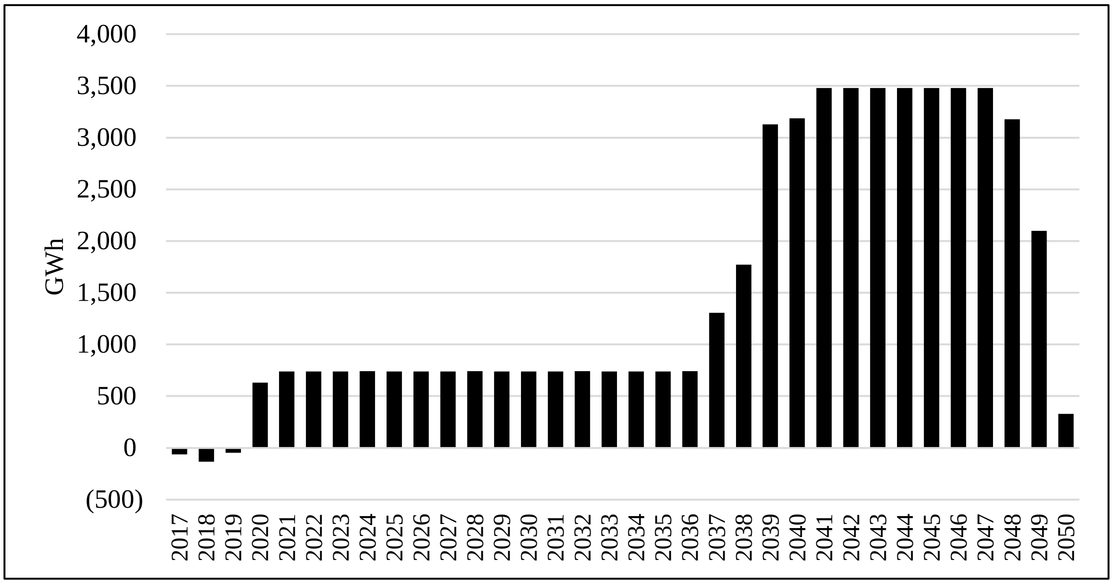
When calculated through 2050, which covers the remaining life of the repowered facilities, the wind repowering project reduces customer costs in all nine price-policy scenarios, with PVRR(d) benefits ranging from $121 million in the low natural-gas and medium CO_2 price-policy scenario to $466 million in the high natural-gas and high CO_2 price-policy scenario. Under the central price-policy scenario, assuming medium natural-gas prices and medium CO_2 prices, the PVRR(d) benefits are $273 million.

Q. What causes the increase in PVRR(d) benefits for many of the price-policy scenarios 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 picks up the sizable increase in incremental wind energy output beyond the 20-year forecast period analyzed with the SO model and PaR. As discussed earlier in my testimony, the change in wind energy output between cases with and without wind repowering experiences a step change beyond this 20-year period, when the existing wind facilities would otherwise have hit the end of their depreciable life. Beyond the 20-year forecast period, the change in wind energy output between cases with and without repowering reflects the full energy output from the repowered wind facilities.

Figure 7 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 738 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 3,478 GWh.

Figure 7. Change in Incremental Wind Energy Output Due to Wind Repowering (GWh)



Q. Is there additional potential 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 7 do not reflect the potential value of RECs produced by the repowered facilities. Customer benefits for all price-policy scenarios would improve by approximately $12 million for every dollar assigned to the incremental RECs that will be generated from the wind repowering project through 2050.

Q. Is there additional potential upside to these PVRR(d) results shown in Table 8?

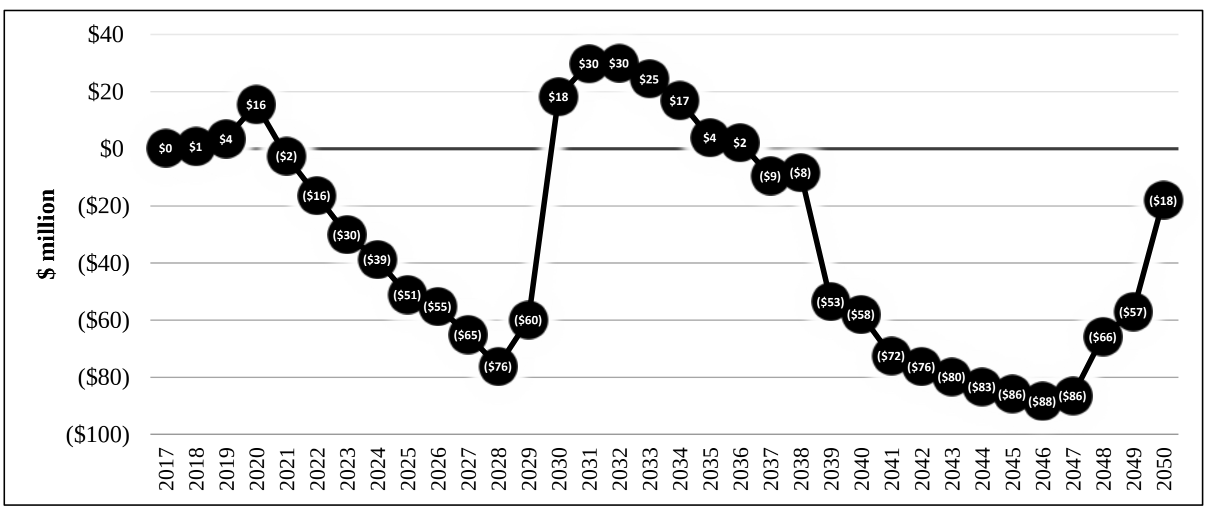
A. Yes. As noted earlier, the updated CO_2 price assumptions used in the economic analysis were inadvertently modeled in 2012 real dollars instead of nominal dollars.

Consequently, the PVRR(d) net benefits in the six price-policy scenarios that use medium and high CO_2 price assumptions are conservative.

Q. Please describe the change in annual nominal revenue requirement from the wind repowering project.

A. Figure 8 shows the updated change in nominal revenue requirement due to the wind repowering project for the medium natural-gas, medium CO_2 price-policy scenario on a total-system basis. The change in nominal revenue requirement shown in the figure reflects updated costs, including capital revenue requirement (*i.e.*, depreciation, return, income taxes, and property taxes), O&M expenses, the Wyoming wind-production tax, and PTCs. The project costs are netted against updated system impacts from the wind repowering project, reflecting the change in NPC, emissions, non-NPC variable costs, and system fixed costs that are affected by, but not directly associated with, the wind repowering project.

Figure 8. Total-System Annual Revenue Requirement With the Wind Repowering Project (Benefit)/Cost ($ million)



As this chart shows, the wind repowering project generates substantial near-term customer benefits and continues to contribute to customer benefits over the long-term. Before repowering, the reduction in wind energy output due to component failures on the existing wind resource equipment is assumed to reduce wind energy output for specific wind turbines until the time new equipment is installed. This contributes to an increase in revenue requirement in 2017 and 2018 ($1 million to $4 million, total system). All but the Dunlap facility, which is repowered toward the end of 2020, are repowered in 2019. Over the 2019-to-2020 time frame, project costs reflecting partial-year capital revenue requirement net of PTCs and system cost impacts cause slight changes to revenue requirement.

The wind repowering project reduces revenue requirement soon after the new equipment is placed in service, and from 2021 through 2028, annual revenue requirement is reduced as PTC benefits increase with inflation and the new equipment continues to depreciate. The reduction in annual revenue requirement is $76 million by 2028. Revenue requirement increases once the PTCs expire toward the end of 2030. Annual revenue requirement is reduced over the 2037-through-2050 time frame when, as discussed earlier in my testimony, the incremental wind energy output associated with wind repowering increases substantially.

Q. Did you evaluate how wind repowering benefits assumed beyond 2036 affect the PVRR(d) results calculated from the change in annual nominal revenue requirement through 2050?

A. Yes. The point of extrapolating results beyond 2036 is to capture the benefits from the significant increase in the expected annual energy output from the repowered wind facilities beyond the period in which the existing wind facilities would have otherwise reached the end of their lives. While the methodology used in my analysis is valid, the value of this incremental energy can be evaluated in different ways.

Table 8 summarizes how the PVRR(d) results through 2050 would change if flat market prices at the Palo Verde (PV) market from the December 29, 2017 OFPC were used as the basis to evaluate the value of incremental energy from wind repowering over the 2037-through-2050 time frame. Recognizing there is both upside and downside price risk to the value of this energy, I assume different levels of PV prices—70 percent of the PV forward curve, 100 percent of the PV forward curve, and 130 percent of the PV forward curve. PacifiCorp's December 29, 2017 OFPC includes forward prices through 2042. Conservatively, I assume no escalation in PV prices beyond 2042 for each of these scenarios. Each of these scenarios is shown alongside the $273 million PVRR(d) net benefit when incremental energy from repowering beyond 2036 is calculated from system modeling results over the 2028 through 2036 time frame.

Table 8. Long-Term Benefit Sensitivity

Source of 2037-2050 Benefits	Nominal Levelized Benefit from 2037-2050	Annual Revenue Requirement PVRR(d) (Benefit)/Cost
2027-2036 System Modeling	$59.08	($273)
70% of PV	$49.49	($213)
100% of PV	$70.70	($351)
130% of PV	$91.92	($489)

This analysis demonstrates that regardless of the methodology used to extend wind repowering benefits to 2050, the PVRR(d) result shows significant customer savings. If the incremental energy is valued at the PV forward curve, the PVRR(d) benefits of the wind repowering project are $351 million, which is $78 million higher than the methodology used in my analysis.

<u>New Wind Sensitivity Study</u>

Q. Did PacifiCorp produce any sensitivities on its economic analysis of the wind repowering project?

A. Yes. PacifiCorp developed a sensitivity to quantify how the net benefits of wind repowering are affected when combined with 1,170 MW of new Wyoming wind resources and the Aeolus-to-Bridger/Anticline transmission included in the company's 2017 IRP.[7] This sensitivity assumes the new wind and transmission is operational by the end of 2020.

Q. Please summarize the results of the sensitivity that includes new Wyoming wind resources and the planned Aeolus-to-Bridger/Anticline transmission project.

A. Table 9 summarizes the PVRR(d) results for the new wind sensitivity that assumes wind repowering is implemented in combination with adding 1,170 MW of new Wyoming wind and the Aeolus-to-Bridger/Anticline transmission project. This sensitivity was developed using SO model and PaR simulations through 2036 for the medium natural-gas, medium CO_2 and the low natural-gas, zero CO_2 price-policy scenarios. The results are shown alongside the base repowering study presented above in which wind repowering was evaluated without the new wind and transmission

[7] The 2017 IRP assumed 1,100 MW of new Wyoming wind by the end of 2020. Since filing the 2017 IRP, PacifiCorp issued its 2017R RFP and initially identified 1,170 MW of new Wyoming wind to the final shortlist, which serves as the basis for this sensitivity. PacifiCorp has since updated its 2017R RFP final shortlist to include 1,311 MW of new Wyoming wind.

Table 9. New Wind and Aeolus-to-Bridger/Anticline Sensitivity (Benefit)/Cost of Wind Repowering ($ million)

	Sensitivity (Repowering + New Wind & Trans.) PVRR(d)	Base Study (Repowering) PVRR(d)	Change in PVRR(d)
Medium Gas, Medium CO_2			
SO Model	($532)	($204)	($328)
PaR Stochastic Mean	($466)	($180)	($286)
PaR Risk Adjusted	($489)	($189)	($300)
Low Gas, Zero CO_2			
SO Model	($301)	($159)	($142)
PaR Stochastic Mean	($300)	($141)	($159)
PaR Risk Adjusted	($315)	($148)	($167)

Customer benefits increase significantly when the wind repowering project is implemented with the new wind and transmission in both the medium natural-gas, medium CO_2 and the low natural-gas, zero CO_2 price-policy scenarios. These results demonstrate that customer benefits not only persist, but increase, if both the wind repowering project and the new wind and transmission projects are completed.

V. CONCLUSION

Q. Please summarize the conclusions of your testimony.

A. The conclusions of my Jim Bridger SCR emission control system testimony are as follows:

- The base case analysis results in a PVRR(d) that is $183 million favorable to the Jim Bridger Unit 3 and Unit 4 SCR emission control systems as compared to a natural-gas conversion alternative.
- Additional sensitivity analysis shows a PVRR(d) that is $588 million favorable to the Jim Bridger Unit 3 and Unit 4 SCR emission control systems as compared to an early retirement and resource replacement alternative.

- Natural-gas and CO_2 price scenario results support the SCR systems in all scenarios but those with low-natural-gas price assumptions, which were not projected to reach historical price levels for the next 18 years.

The conclusions of my wind repowering testimony are as follows:

- PacifiCorp's analysis supports repowering approximately 999 MW of existing wind resource capacity located in Wyoming, Oregon, and Washington.
- The repowered wind facilities will qualify for an additional 10 years of federal PTCs, produce more energy, reset the 30-year depreciable life of the assets, and reduce run-rate operating costs.
- The economic analysis of the wind repowering opportunity demonstrates that net benefits, which include federal PTC benefits, NPC benefits, other system variable-cost benefits, and system fixed-cost benefits, more than outweigh net project costs.

Q. What is your recommendation?

A. I recommend the Commission determine that both the decision to install SCR emission control systems on Jim Bridger Units 3 and 4, and the decision to repower certain wind facilities is prudent and in the public interest and therefore approve the application as filed.

Q. Does this conclude your direct testimony?

A. Yes.