WUTC DOCKET: UE-191024
EXHIBIT: RTL-1CT (R)
ADMIT ☑ W/D ☐ REJECT ☐

Confidential per WAC 480-07-160
Exh. RTL-1CT
Docket UE-19____
Witness: Rick T. Link

BEFORE THE WASHINGTON

UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PACIFICORP dba PACIFIC POWER & LIGHT COMPANY Respondent.	Docket UE-19____

PACIFICORP

REDACTED DIRECT TESTIMONY OF RICK T. LINK

December 2019

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

A. My name is Rick T. Link. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My position is Vice President, Resource Planning and Acquisitions. I am testifying on behalf of PacifiCorp dba Pacific Power & Light Company (PacifiCorp or the Company).

Q. Please describe the responsibilities of your current position.

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

Q. Please describe your professional experience and education.

A. I joined PacifiCorp in December 2003 and assumed the responsibilities of my current position in September 2016. Over this time period, I held several analytical and leadership positions responsible for developing long-term commodity price forecasts, pricing structured commercial contract opportunities and developing financial models to evaluate resource investment opportunities, negotiating commercial contract terms, and overseeing development of PacifiCorp's resource plans. I was responsible for delivering PacifiCorp's 2013, 2015, 2017, and 2019 IRPs; have been directly involved in several resource RFP processes; and performed economic analysis supporting a range of resource investment opportunities. Before joining PacifiCorp, I was an energy and environmental economics consultant with ICF Consulting (now

ICF International) from 1999 to 2003, where I performed electric-sector financial modeling of environmental policies and resource investment opportunities for utility clients. I received a Bachelor of Science degree in Environmental Science from the Ohio State University in 1996 and a Masters of Environmental Management from Duke University in 1999.

Q. Have you testified in previous regulatory proceedings?

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

PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

A. PacifiCorp's Energy Vision 2020 uses opportunities presented by the extension of the federal production tax credit (PTC) to make renewable energy and infrastructure investments that produce net benefits to customers. Energy Vision 2020 consists of two major components, both of which are included in this case: (1) wind repowering; and (2) investments in new wind and transmission. In my testimony, I present and explain the economic analysis that demonstrates that these investments are prudent, used and useful, and further the public interest.

In addition to Energy Vision 2020, PacifiCorp has acquired another wind resource, the Pryor Mountain Wind Project in Montana, which will achieve commercial operation in 2020. I present and explain the economic analysis that demonstrates that this investment is prudent, used and useful as of the rate effective date, and furthers the public interest. I also present the Company's load forecast upon which this rate case filing was based.

Q. How have you organized your testimony?

A. I have divided my testimony into four sections. I address PacifiCorp's wind repowering project in Section I of my testimony. I address PacifiCorp's new wind and transmission investments, collectively referred to as the "Combined Projects" in Section II of my testimony. Section III of my testimony addresses PacifiCorp's new Pryor Mountain Wind Project, and Section IV presents PacifiCorp's load forecast.

I. WIND REPOWERING

Q. Please summarize Section I of your testimony.

A. PacifiCorp's economic analysis that shows that its decision to "repower" its wind fleet is prudent, in the public interest, and provides significant customer benefits. The wind repowering project includes 13 wind facilities, representing 1,039.9 megawatts (MW) of installed wind capacity. PacifiCorp's underlying economic analysis covers 12 of the 13 wind facilities, totaling approximately 999.1 MW—Glenrock I, Glenrock III, Rolling Hills, Seven Mile Hill I, Seven Mile Hill II, High Plains, McFadden Ridge, and Dunlap in Wyoming; Marengo I, Marengo II and Goodnoe Hills in Washington; and Leaning Juniper in Oregon. This filing includes the 13^{th} facility, Foote Creek I in Wyoming, which presents similar economic benefits.

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. PacifiCorp's economic analysis of the wind repowering project 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.

Based on an economic analysis completed in February 2018 covering all facilities except Foote Creek I, my testimony shows that:

- The wind repowering project will deliver net customer benefits in all price-policy scenarios studied.
- The wind repowering project will produce present-value net customer benefits, based on analysis covering the remaining life of the repowered wind facilities, ranging between $121 million to $466 million (total system).
- 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 project costs totaling $1.01 billion.
- These net and gross customer benefits are conservative, as they do not account for potential incremental benefits from renewable energy credits (RECs), understate the potential benefits from reduced carbon-dioxide (CO_2) emissions, and assign no incremental capacity value associated with extending the life of the repowered wind facilities by 10–13 years.
- When measured over a 20-year period, the present value of net customer benefits from wind repowering range between $139 million and $273 million, which accounts for the nominal value of federal PTCs, but does not account for the value of incremental energy output that will increase significantly beyond 2036.

PacifiCorp performed updated analysis in August 2018 to understand how more recent changes in other modeling assumptions affect project-by-project results relative to those included in the February 2018 analysis. Based on this updated economic analysis, my testimony shows that projected net customer benefits remain similar to those calculated previously. This targeted reassessment confirms that the repowering project is prudent. As with the February 2018 results, the net customer benefits projected in the August 2018 analyses are conservative, as they do not account for potential incremental benefits from RECs and assign no incremental capacity value associated with extending the life of the repowered wind facilities by 10-13 years.

2017 INTEGRATED RESOURCE PLAN

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

A. Yes. The preferred portfolio in the 2017 IRP, representing PacifiCorp's risk-adjusted, least-cost plan to reliably meet customer demand over a 20-year planning period, includes repowering 905 MW of existing wind resource capacity located in Wyoming, Washington, and Oregon. PacifiCorp later expanded the wind repowering scope to include its Goodnoe Hills and Foote Creek I wind facilities, increasing the project to approximately 1,040 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, 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 PTC equates to a $33.15/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, PacifiCorp will operate the repowered wind turbines under full service agreements (FSAs) with the original equipment manufacturer for 10 years to perform all routine operations and maintenance (O&M) and capital replacements during the contract, which will avoid capital expenditures that would otherwise be needed to replace or refurbish existing equipment. Moreover, PacifiCorp anticipates that new, modern equipment will reduce failure rates for certain wind turbine components within the wind fleet that were experiencing high failure rates.

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. Of the 905 MW of existing wind resource capacity in the 2017 IRP, approximately 594 MW of this capacity are located in Wyoming (Glenrock, Rolling Hills, Seven Mile Hill, High Plains, 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 the scope of the wind repowering project to include Goodnoe Hills, located in Washington and Foote Creek I, located in Wyoming.

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 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 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 actions.

Q. Did PacifiCorp include a wind repowering action item in its 2017 IRP action plan?

A. Yes. The 2017 IRP action plan, which lists 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 engineering, procurement and construction 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.

Q. Did the Commission acknowledge the 2017 IRP?

A. Yes. In Docket UE-160353, the Commission acknowledged the 2017 IRP in a letter dated May 7, 2018.

Q. Did PacifiCorp update its economic analysis of wind repowering in the 2017 IRP Update to account for federal income tax changes?

A. Yes. PacifiCorp developed its February 2018 analysis and included it in the 2017 IRP Update. This analysis confirmed that wind repowering continues to provide significant net benefits to customers after accounting for changes in the federal income tax law.

Q. How did PacifiCorp address its wind repowering analysis in the 2019 IRP?

A. The 2019 IRP incorporates repowering approximately 999.1 MW of existing wind resource capacity for 12 wind facilities. The repowering of these 12 wind facilities was not evaluated in the 2019 IRP; however, new resource acquisitions were evaluated assuming repowering.

Q. In the 2017 IRP analysis, PacifiCorp assumed the turbine-supply contracts would include a two-year warranty on the new equipment. What is the updated assumption?

A. PacifiCorp plans to operate the repowered facilities under 10-year FSAs with the original equipment manufacturers to perform all routine O&M and capital replacements during the contract term. After the expiration of the FSAs PacifiCorp expects to perform all maintenance and capital replacements.

The annual cost of the FSAs will be classified to capital or expense based on the nature of the work performed. This allocation will vary from year to year and from plant to plant. However, based on its experience with similar contracts, PacifiCorp expects that approximately 55 percent of the total cost of the FSAs will be classified as capital.

MODELING SCOPE, METHODOLOGIES, AND ASSUMPTIONS

Q. What wind resources did PacifiCorp include in its economic analysis of the wind repowering project, and how do those resources relate to this filing?

A. As noted above, PacifiCorp prepared its main economic analysis of the wind repowering project in February 2018. The economic analysis covers 12 wind facilities (all except Foote Creek I), and estimates customer benefits from repowering these facilities comprising approximately 999.1 MW of existing wind resource capacity located in Wyoming, Oregon, and Washington in 2019 and 2020. The economic analysis informed PacifiCorp's decision to move forward with the project.

Modeling Methodology

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

A. PacifiCorp relied on 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 present-value revenue requirement differential (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 net benefits when the system PVRR with wind repowering is lower than the system PVRR without wind 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 economic analysis of the wind repowering project?

A. PacifiCorp used the System Optimizer (SO) model and the Planning and Risk model (PaR) to develop resource portfolios and to forecast dispatch of system resources in simulations with and without 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 new 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 PaR 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. For example, the models were used to support the successful acquisition of the Chehalis combined-cycle plant. These models were also 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, both of which are discussed below.

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 risk-adjusted, least-cost 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. Accounting for recent changes in tax law, the discount rate used in the economic analysis 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. At the time, federal PTCs were $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 assumptions. These price-policy 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?

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). Subsequent to this economic analysis the cost of the Leaning Juniper project was reduced and its performance increased resulting in a decrease in total capital project costs and an increase in annual energy output. Additionally, repowering Foote Creek I was later added by the Company, so its costs and energy benefits are not accounted in these numbers.

The cost-and-performance assumptions for the wind facilities studied in this updated economic analysis are summarized in Confidential Exhibit No. RTL-2C. In addition, as described further below, several other assumptions were updated in the August 2018 analysis to align with updates included in the 2017 IRP Update, which was filed after the February 2018 analysis was completed.

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 30-year depreciable life of each repowered facility.

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 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 from 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.

Price-Policy Scenarios

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. I present two vintages of the wind repowering economic analysis—a complete set of studies was prepared in February 2018 and a more targeted set of studies was prepared in August 2018 as validation. The February 2018 analysis represents the final set of studies used to support PacifiCorp's pre-approval proceedings in Idaho, Utah, and Wyoming. The August 2018 analysis was prepared to understand how updates to certain modeling assumptions, which I describe later in my testimony, affect the economic analysis that was prepared in February 2018. The specific price-policy scenarios used in each of these studies are described further below.

February 2018 Price-Policy Assumptions

Q. What price-policy assumptions did PacifiCorp use in its February 2018 wind repowering analysis?

A. 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.

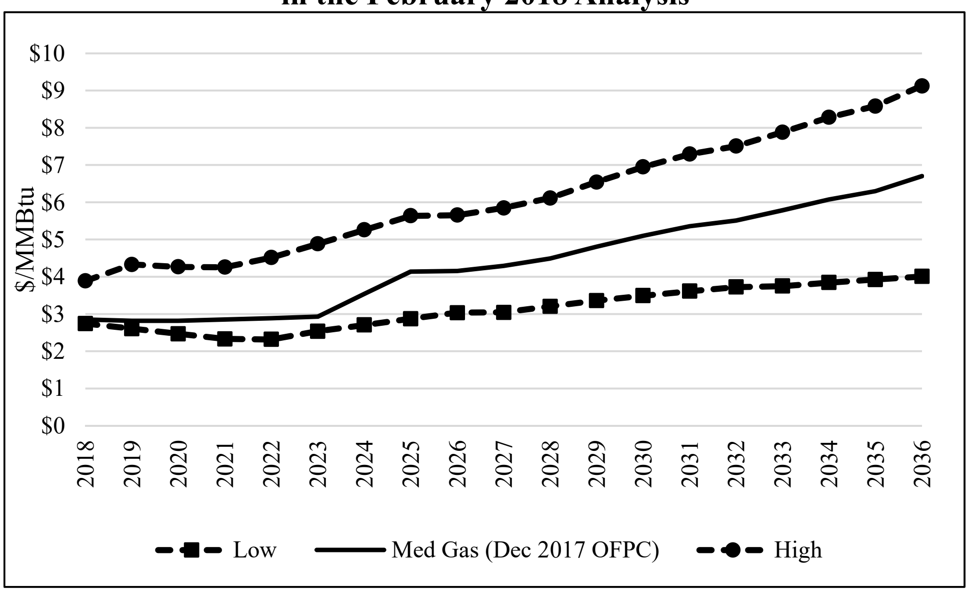
Q. Please describe the natural-gas price assumptions used in the February 2018 price-policy scenarios.

A. The medium-natural-gas price assumptions that are paired with zero CO_2 prices reflect natural-gas prices from PacifiCorp's official forward price curve (OFPC) dated 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 third-party forecasting service. 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. Confidential Exhibit No. RTL-3C 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 also derived from a low-price scenario developed by a third-party forecasting service. 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 is extremely difficult to project with reasonable accuracy.

Figure 1 shows Henry Hub natural-gas price assumptions from the December 2017 OFPC, low-, and high-natural-gas price scenarios.

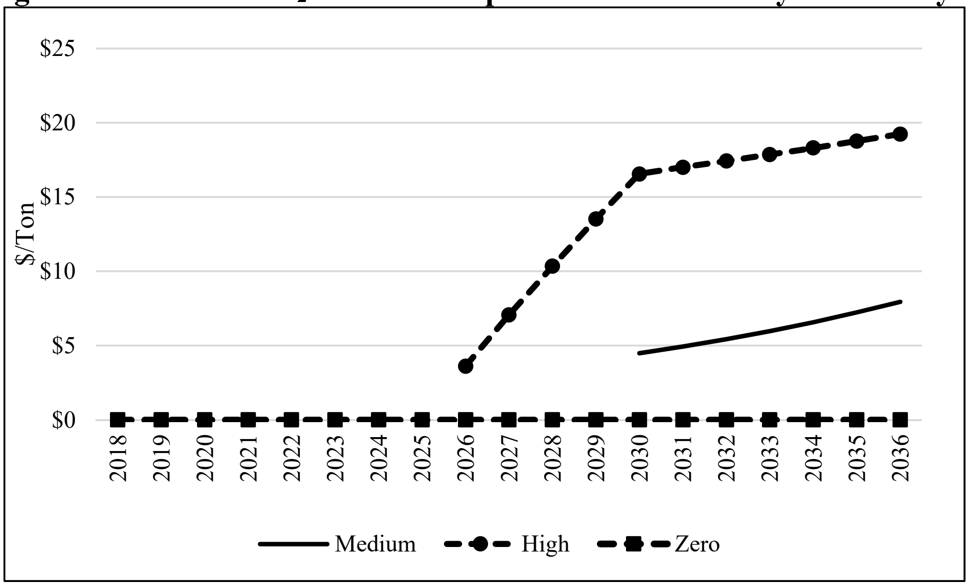
Figure 1. Nominal Natural-Gas Price Scenarios in the February 2018 Analysis



Q. Please describe the CO_2 price assumptions used in the February 2018 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 2 shows the CO_2 price assumptions used to analyze the wind repowering project.

Figure 2. Nominal CO_2 Price Assumptions in the February 2018 Analysis



August 2018 Price-Policy Assumptions

Q. What price-policy assumptions did PacifiCorp use in its August 2018 wind repowering analysis?

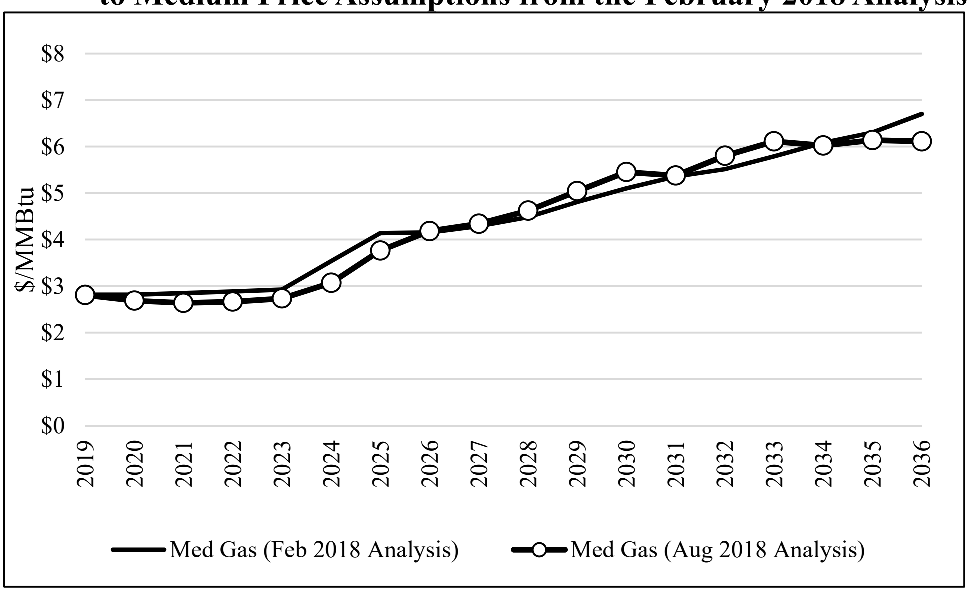
A. In August 2018, PacifiCorp conducted a more targeted wind repowering analysis to understand how the results were impacted by certain assumption updates, which I describe later in my testimony. For this study, therefore, PacifiCorp only updated its medium natural-gas price and CO_2 price assumptions.

Q. Please describe the natural-gas price assumption used in the August 2018 price-policy scenario.

A. The medium-natural-gas price assumption that is paired with medium CO_2 prices reflect natural-gas prices from PacifiCorp's OFPC dated June 29, 2018. This OFPC uses observed forward market prices as of June 29, 2018, for 72 months, followed by a 12-month transition to natural-gas prices based on an updated forecast developed by [redacted].

Figure 3 shows Henry Hub natural-gas price assumptions used in the August 2018 wind repowering analysis alongside the medium-natural-gas price assumptions used in the February 2018 wind repowering analysis. The nominal levelized price over the period 2019 through 2036 from the August 2018 analysis is $3.97/MMBtu, which is down just two percent relative to the $4.05/MMBtu levelized price from the February 2018 analysis.

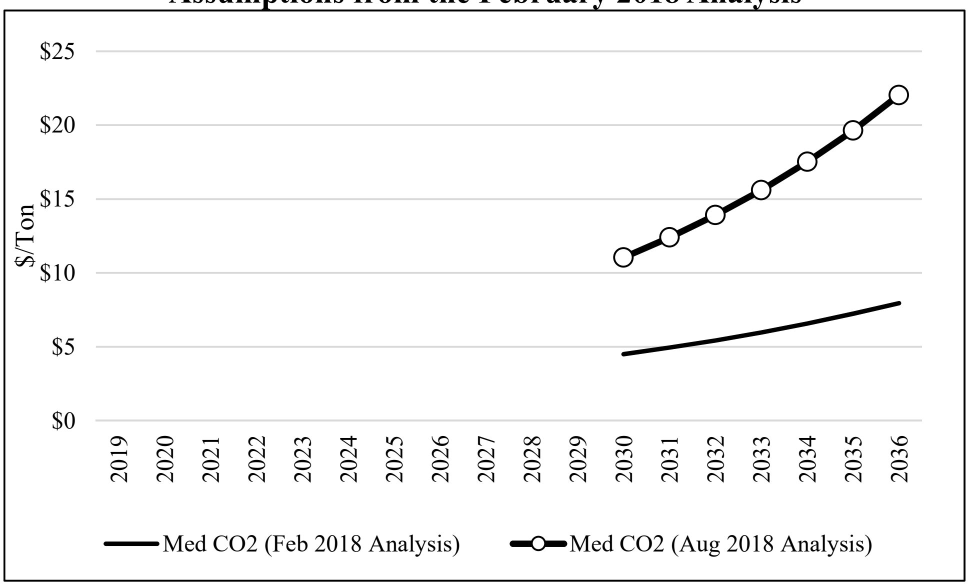
Figure 3. Nominal Natural-Gas Price Assumptions in the August 2018 Analysis Relative to Medium Price Assumptions from the February 2018 Analysis



Q. Please describe the CO_2 price assumption used in the August 2018 price-policy scenario.

A. As with natural-gas prices, the medium CO_2 price assumption is based on a forecast from [redacted]. Figure 4 shows how the CO_2 price assumptions used in the August 2018 wind repowering analysis compares to the medium assumption used in the February 2018 wind repowering analysis. In both instances, the CO_2 price is applied beginning 2030, and while the CO_2 price used in the August 2018 analysis is higher, this is driven by the fact that CO_2 price assumptions used in the February 2018 analysis were inadvertently modeled in 2012 real dollars instead of nominal dollars. As noted below, this was corrected in the August 2018 analysis, which was modeled in nominal dollars. The CO_2 price assumptions used in the August 2018 analysis applies inflation to determine the prices in nominal dollars.

Figure 4. CO_2 Price Assumptions in the August 2018 Analysis Relative to Medium Price Assumptions from the February 2018 Analysis



Other Assumption Updates in the August 2018 Analysis

Q. Beyond the price-policy assumptions discussed earlier in your testimony, what other assumptions did you update in the August 2018 wind repowering analysis?

A. The August 2018 analysis includes updated hourly market price profiles, updated firm resources, which includes 1,150 MW of new Wyoming wind resource capacity consistent with the final shortlist from the 2017R RFP and inclusion of the Aeolus-to-Bridger/Anticline transmission line, updated proxy resource costs for new wind and solar resources, and updated inflation rate assumptions. The August 2018 analysis also reflects an updated load forecast, which was refreshed after PacifiCorp filed its 2017 IRP Update.

Table 1. Updated Assumptions in the August 2018 Analysis Relative to Assumptions from the February 2018 Analysis

Description	February 2018 Analysis	August 2018 Analysis
Load Forecast	August 2017	June 2018
Hourly Price Profile	PowerDex Scalar Method	CAISO Day-Ahead Method
Energy Vision 2020	No New Wind and Transmission	1,150 MW of Wyoming wind and the Aeolus-to-Bridger/Anticline Transmission Line
Other Resources	2017 IRP	2017 IRP Update plus Executed and Planned Solar PPAs
Annual Inflation Rate	2.22%	2.27%
Proxy Resource Costs	2017 IRP	2017 IRP Update

FEBRUARY 2018 WIND REPOWERING ANALYSIS

Project-by-Project Results

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, PacifiCorp 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. 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 (2017$ million), February 2018

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. 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 (2017$ million), February 2018

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)

Project-by-Project Annual Revenue Requirement Price-Policy Results

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 from 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 (2017$ million), February 2018

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 accounting for 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 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 the project-by-project results. However, the capacity of McFadden Ridge (28.5 MW) is approximately 20 percent of the capacity of Marengo I (140.4 MW). Similarly, the expected energy output after repowering McFadden Ridge (approximately 117 GWh per year) is approximately 24 percent of the expected energy output after repowering 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, Table 5 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 (2017$/MWh), February 2018

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	$23/MWh	$14/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, 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 medium natural-gas and medium CO_2 price-policy scenario are conservative.

Project-wide SO and PaR Price-Policy Results

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. The data used to calculate the SO Model PVRR(d) and PaR Stochastic Mean PVRR(d) results shown in Table 6 are provided as Exhibit No. RTL-4.

Table 6. Project-Wide SO Model and PaR PVRR(d) (Benefit)/Cost of the Wind Repowering Projects (2017$ million), February 2018

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 project-wide net benefits increase with higher natural-gas price assumptions, and similarly, generally increase with higher CO_2 price assumptions. Conversely, project-wide 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 simply to 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, such as those PacifiCorp is subject to in Washington. Moreover, 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.

Project-Wide Annual Revenue Requirement Price-Policy Results

Q. Please summarize the PVRR(d) results for the full scope of the wind repowering project as calculated from the change in annual revenue requirement through 2050.

A. Table 7 summarizes the PVRR(d) results for the full scope of the wind repowering project for each price-policy scenario calculated from the change in annual nominal revenue requirement through 2050. The annual data over the period 2017 through 2050 that were used to calculate the PVRR(d) results shown in Table 7 are provided as Exhibit No. RTL-5.

Table 7. Project-Wide Nominal Revenue Requirement PVRR(d) (Benefit)/Cost of Wind Repowering (2017$ million), February 2018

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 are the gross customer benefits of the repowering project and how do those gross benefits compare to project costs?

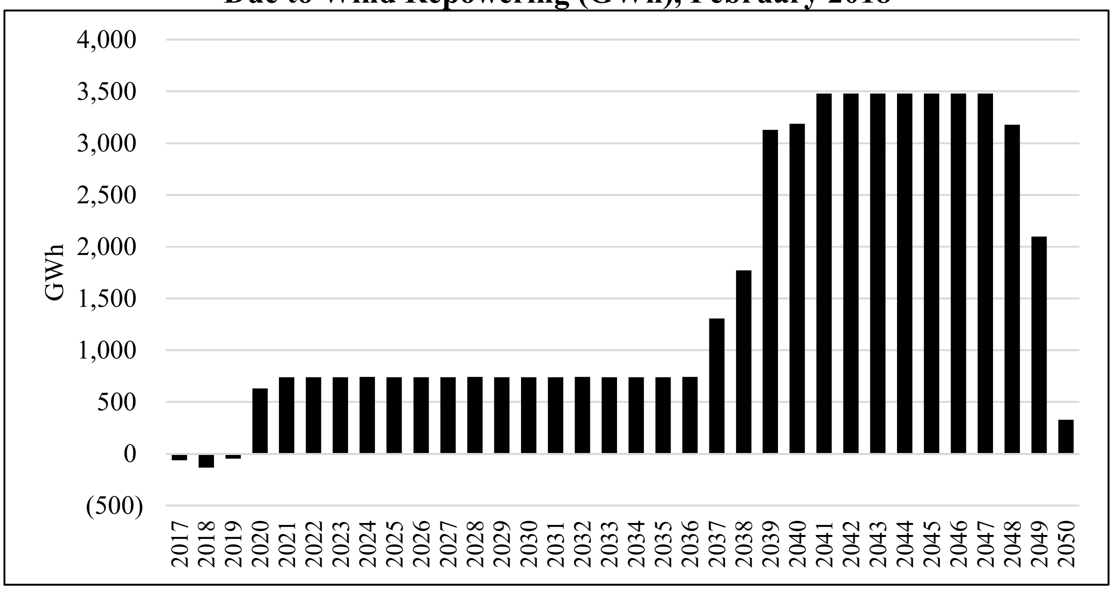
A. Present-value gross customer benefits calculated over the remaining life of the repowered wind facilities range between $1.14 billion and $1.48 billion, which compares to present-value project costs totaling $1.01 billion.

Q. What causes the increase in PVRR(d) benefits for many of the price-policy scenarios when calculated from 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 5 shows the incremental change in wind energy output resulting from the repowering project. Incremental energy output associated with wind repowering progressively increases over the 2036-through-2040 period, as wind facilities originally placed in service in the 2006-through-2010 time frame would have otherwise hit the end of their lives. Before 2036, and once all 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 5. Change in Incremental Wind Energy Output Due to Wind Repowering (GWh), February 2018



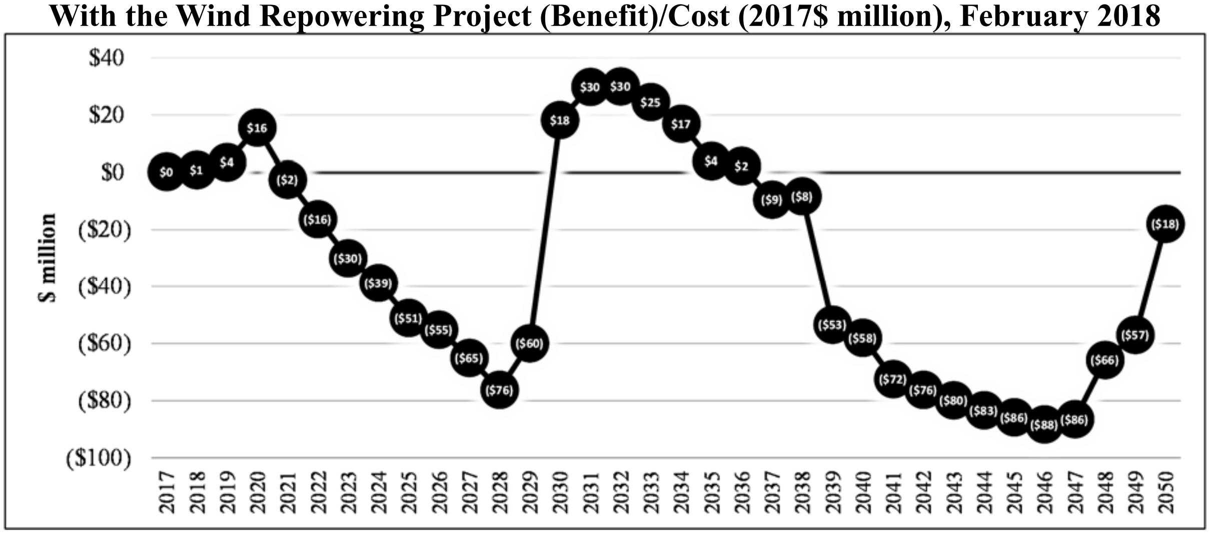
Q. Is there additional potential upside to the PVRR(d) results calculated from the change in estimated annual revenue requirement through 2050?

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. Moreover, as noted earlier, the CO_2 price assumptions used in the February 2018 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 6 shows the change in nominal revenue requirement due to the wind repowering project for the medium natural-gas and medium CO_2 price-policy scenario on a total-system basis. The change in nominal revenue requirement shown in the figure reflects project 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 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 6. Total-System Annual Revenue Requirement With the Wind Repowering Project (Benefit)/Cost (2017$ million), February 2018



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). In the February 2018 analysis, all the facilities were assumed to be repowered in 2019, except the Dunlap facility, which was assumed to be repowered toward the end of 2020. 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, February 2018

Source of 2037-2050 Benefits	Nominal Levelized Benefit from 2037-2050 ($/MWh)	Annual Revenue Requirement PVRR(d) (Benefit)/Cost ($ million)
2027-2036 System	$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.

New Wind and Transmission Sensitivity

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

A. Yes. In the February 2018 analysis, 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 project included in the Company's 2017 IRP. As discussed in Section II of my testimony, the 2017 IRP assumed 1,100 MW of new Wyoming wind by the end of 2020. After filing the 2017 IRP, PacifiCorp issued its 2017R RFP and initially identified 1,170 MW of new Wyoming wind to the final shortlist, which served as the basis for this sensitivity. PacifiCorp later updated its 2017R RFP final shortlist to include 1,150 MW of new Wyoming wind. This sensitivity was based on the assumption that the new wind and transmission would be 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

Table 9. New Wind and Aeolus-to-Bridger/Anticline Sensitivity (Benefit)/Cost of Wind Repowering (2017$ million), February 2018

	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	($466)	($180)	($286)
PaR Risk Adjusted	($489)	($189)	($300)
Low Gas, Zero CO_2			
SO Model	($301)	($159)	($142)
PaR Stochastic	($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.

AUGUST 2018 WIND REPOWERING ANALYSIS

Project-by-Project SO and PaR Model Price-Policy Results

Q. Please summarize the scope of the approach taken in the August 2018 analysis, relative to the February 2018 analysis, including the price-policy scenarios used.

A. For the August 2018 analysis, PacifiCorp performed a project-by-project economic analysis that was updated to account for more current modeling assumptions, using the same basic methodology used in the February 2018 analysis: SO model and PaR studies through 2036 (levelized capital and nominal treatment of PTCs); and nominal revenue requirement analysis through 2050 (nominal capital and nominal treatment of PTCs). PacifiCorp performed the updated analysis in August 2018 for each facility using medium natural gas and medium CO_2 price-policy assumptions.

For Leaning Juniper, PacifiCorp also performed an updated analysis in August 2018 using the most conservative low natural gas and zero CO_2 price-policy assumptions. This additional price-policy scenario was analyzed for the Leaning Juniper facility because its cost-and-performance assumptions had improved relative to the February 2018 analysis where Leaning Juniper presented the lowest customer net benefits relative to other wind facilities.

Q. How did the cost-and-performance assumptions change for Leaning Juniper in the August 2018 analysis relative to the February 2018 analysis?

A. After evaluating alternative equipment suppliers, the capital cost required to repower Leaning Juniper was reduced by approximately [redacted] from [redacted] to [redacted] and the expected increase in annual energy output increased from [redacted] percent to [redacted] percent.

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 10 summarizes the PVRR(d) results for each wind facility. With the passage of time between the February 2018 and August 2018 analyses, PVRR(d) results from the August 2018 analysis are discounted back to 2018 dollars. Results from the February 2018 analysis are discounted back to 2017 dollars. 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, all wind facilities are projected to deliver net benefits.

Table 10. 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 (2018$ million); August 2018

Wind Facility	SO Model PVRR(d)	PaR Stochastic-Mean PVRR(d)	PaR Risk-Adjusted PVRR(d)
Glenrock 1	($29)	($24)	($31)
Glenrock 3	($10)	($8)	($11)
Seven Mile Hill 1	($40)	($31)	($39)
Seven Mile Hill 2	($9)	($8)	($9)
High Plains	($23)	($14)	($21)
McFadden Ridge	($7)	($5)	($7)
Dunlap Ranch	($37)	($28)	($37)
Rolling Hills	($16)	($11)	($16)
Leaning Juniper	($10)	($10)	($10)
Marengo 1	($44)	($33)	($43)
Marengo 2	($20)	($15)	($20)
Goodnoe Hills	($24)	($20)	($26)

Q. How do the August 2018 results in Table 10 compare with February 2018 results assuming medium natural-gas and medium CO_2 price-policy assumptions?

A. Using the medium natural-gas and medium CO_2 price-policy assumptions, the August 2018 project-by-project PVRR(d) results calculated from the SO model and PaR through 2036 are similar to, and generally improve upon, projected customer benefits relative to the February 2018 project-by-project PVRR(d) results. As discussed further below, a particularly notable change is evident for Leaning Juniper. This facility was projected in February 2018 to provide net zero customer benefits, but with improved cost-and-performance assumptions applied in the August 2018 analysis is projected to provide $10 million in net positive customer benefits.

Table 11 displays the two sets of analyses side by side. These results confirm that with updated assumptions, the conclusions from the February 2018 study—

implementing the repowering project will provide substantial customer benefits—remain valid.

Table 11. 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); February and August 2018

Wind Facility	SO Model PVRR(d)		PaR Stochastic-Mean PVRR(d)		PaR Risk-Adjusted PVRR(d)	
	February 2018 (2017$)	August 2018 (2018$)	February 2018 (2017$)	August 2018 (2018$)	February 2018 (2017$)	August 2018 (2018$)
Glenrock 1	($25)	($29)	($21)	($24)	($23)	($31)
Glenrock 3	($8)	($10)	($7)	($8)	($7)	($11)
Seven Mile Hill	($33)	($40)	($28)	($31)	($29)	($39)
Seven Mile Hill	($7)	($9)	($7)	($8)	($7)	($9)
High Plains	($17)	($23)	($13)	($14)	($13)	($21)
McFadden Ridge	($5)	($7)	($4)	($5)	($4)	($7)
Dunlap Ranch	($30)	($37)	($26)	($28)	($27)	($37)
Rolling Hills	($12)	($16)	($9)	($11)	($10)	($16)
Leaning Juniper	($0)	($10)	($0)	($10)	($0)	($10)
Marengo 1	($35)	($44)	($33)	($33)	($34)	($43)
Marengo 2	($15)	($20)	($14)	($15)	($15)	($20)
Goodnoe Hills	($18)	($24)	($18)	($20)	($19)	($26)

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

A. Table 12 summarizes the PVRR(d) results for the Leaning Juniper facility when applying low natural-gas and zero CO_2 price-policy assumptions. Results, which represent the PVRR(d) between cases with and without repowering the Leaning Juniper facility, are shown alongside those reported from the February 2018 analysis. The PVRR(d) results in Table 12 are from the SO model and PaR, before accounting for the substantial increase in incremental energy beyond the 2036 time frame. Under this most conservative price-policy scenario, the Leaning Juniper facility is still projected to deliver net benefits, and driven by improved cost-and-performance assumptions, these net benefits improve relative to the February 2018 PVRR(d) results. These results confirm that with updated assumptions, implementing the entire repowering project, including at the Leaning Juniper facility, will provide customer benefits and is therefore prudent.

Table 12. Leaning Juniper SO Model and PaR PVRR(d) (Benefit)/Cost of Wind Repowering with Low Natural-Gas and Zero CO_2 Price-Policy Assumptions ($ million); February and August 2018

Wind Facility	SO Model PVRR(d)		PaR Stochastic-Mean PVRR(d)		PaR Risk-Adjusted PVRR(d)	
	February 2018	August 2018	February 2018	August 2018	February 2018	August 2018
Leaning Juniper	$6	($5)	$3	($4)	$4	($4)

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

A. Yes. As is the case for the February 2018 analysis, the PVRR(d) results presented in Tables 10 and 12 do not reflect the potential value of RECs generated by the incremental energy output from the repowered facilities.

Project-by-Project Annual Revenue Requirement Price-Policy Results

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

A. Table 13 summarizes the PVRR(d) results for each wind facility calculated from the change in annual nominal revenue requirement through 2050 for the medium natural-gas and medium CO_2 price-policy scenario. Unlike the results summarized in Table 10, 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.

Table 13. Project-by-Project Nominal Revenue Requirement PVRR(d) (Benefit)/Cost of Wind Repowering (2018$ million), with Medium Natural-Gas and Medium CO_2 Price-Policy Assumptions; August 2018

Wind Facility	Nom. Rev. Req. PVRR(d) (Benefit)/Cost
Glenrock 1	($35)
Glenrock 3	($10)
Seven Mile Hill 1	($43)
Seven Mile Hill 2	($9)
High Plains	($19)
McFadden Ridge	($5)
Dunlap Ranch	($39)
Rolling Hills	($15)
Leaning Juniper	($21)
Marengo 1	($46)
Marengo 2	($17)
Goodnoe Hills	($25)

Q. How do the August 2018 results in Table 13 compare with the February 2018 analysis assuming medium natural-gas and medium CO_2 price-policy assumptions?

A. Using the medium natural-gas and medium CO_2 price-policy assumptions, the August 2018 project-by-project PVRR(d) results calculated from change in annual nominal revenue requirement through 2050 are similar to the February 2018 results. Table 14 displays the two sets of analyses side by side. These results confirm that with updated assumptions, the conclusions from the February 2018 study—implementing the repowering project will provide substantial customer benefits—remain valid.

Table 14. Project-by-Project Nominal Revenue Requirement PVRR(d) (Benefit)/Cost of Wind Repowering ($ million), with Medium Natural-Gas and Medium CO_2 Price-Policy Assumptions; February and August 2018

Wind Facility	Nom. Rev. Req. PVRR(d) (Benefit)/Cost	
	February 2018 (2017$)	**August 2018 (2018$)**
Glenrock 1	($33)	($35)
Glenrock 3	($11)	($10)
Seven Mile Hill 1	($41)	($43)
Seven Mile Hill 2	($10)	($9)
High Plains	($22)	($19)
McFadden Ridge	($7)	($5)
Dunlap Ranch	($39)	($39)
Rolling Hills	($15)	($15)
Leaning Juniper	($8)	($21)
Marengo 1	($50)	($46)
Marengo 2	($20)	($17)
Goodnoe Hills	($26)	($25)

Q. Please summarize the PVRR(d) results for the Leaning Juniper facility calculated from the change in annual revenue requirement through 2050 when assuming low natural-gas and zero CO_2 price-policy assumptions.

A. Table 15 summarizes the PVRR(d) results for the Leaning Juniper facility when applying low natural-gas and zero CO_2 price-policy assumptions. Results, which represent the PVRR(d) between cases with and without repowering the Leaning Juniper facility, are shown alongside those reported from the February 2018 analysis. The PVRR(d) results in Table 15 are based on system modeling results from the change in annual revenue requirement through 2050. Under this most conservative price-policy scenario, the Leaning Juniper facility is still projected to deliver net benefits, and driven by improved cost-and-performance assumptions, these net benefits improve relative to the February 2018 PVRR(d) results. These results confirm that with updated assumptions, implementing the entire repowering project, including at the Leaning Juniper facility, will provide customer benefits and is therefore prudent.

Table 15. Leaning Juniper Nominal Revenue Requirement PVRR(d) (Benefit)/Cost of Wind Repowering ($ million), with Low Natural-Gas and Zero CO_2 Price-Policy Assumptions; February and August 2018

Wind Facility	Nom. Rev. Req. PVRR(d) (Benefit)/Cost	
	February 2018 (2017$)	August 2018 (2018$)
Leaning Juniper	($0)	($4)

Q. Have you calculated the net benefits of the wind repowering project considering the size of each wind facility?

A. Yes. As discussed above, the metric of nominal levelized net benefit per incremental MWh expected after the facility is repowered 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 16 shows the nominal levelized net benefit of repowering per MWh of expected incremental energy output after repowering each wind facility. When using medium natural-gas and medium CO_2 price-policy assumptions, Table 16 shows the Glenrock 1, Seven Mile Hill 1, and Seven Mile Hill 2 facilities produce the largest net benefit per incremental MWh ($29/MWh), and McFadden Ridge produces the smallest net benefit per incremental MWh ($12/MWh).

Table 16. Project-by-Project Nominal Levelized Net Benefit per MWh of Incremental Energy Output after Repowering (2018$/MWh), with Medium Natural-Gas and Medium CO_2 Price-Policy Assumptions; August 2018

Wind Facility	Nom. Lev. $/MWh
Glenrock 1	$29/MWh
Glenrock 3	$25/MWh
Seven Mile Hill 1	$29/MWh
Seven Mile Hill 2	$29/MWh
High Plains	$14/MWh
McFadden Ridge	$12/MWh
Dunlap Ranch	$27/MWh
Rolling Hills	$17/MWh
Leaning Juniper	$17/MWh
Marengo 1	$21/MWh
Marengo 2	$17/MWh
Goodnoe Hills	$23/MWh

Q. How do the August 2018 results in Table 16 compare with the previous analysis in February 2018 assuming medium natural-gas and medium CO_2 price-policy assumptions?

A. Using the medium natural-gas and medium CO_2 price-policy assumptions, the August 2018 project-by-project metrics for nominal levelized net benefit per incremental MWh expected after the facility is repowered are similar to the February 2018 results under the same price-policy scenario. Table 17 displays the two sets of analyses side by side. These results confirm that with updated assumptions, the conclusions from the February 2018 study—implementing the repowering project will provide substantial customer benefits—remain valid.

Table 17. Project-by-Project Nominal Levelized Net Benefit per MWh of Incremental Energy Output after Repowering ($/MWh), with Medium Natural-Gas and Medium CO_2 Price-Policy Assumptions; February and August 2018

Wind Facility	Nom. Lev. $/MWh	
	February 2018	**August 2018**
Glenrock 1	$29/MWh	$29/MWh
Glenrock 3	$28/MWh	$25/MWh
Seven Mile Hill 1	$30/MWh	$29/MWh
Seven Mile Hill 2	$36/MWh	$29/MWh
High Plains	$17/MWh	$14/MWh
McFadden Ridge	$17/MWh	$12/MWh
Dunlap Ranch	$28/MWh	$27/MWh
Rolling Hills	$19/MWh	$17/MWh
Leaning Juniper	$7/MWh	$17/MWh
Marengo 1	$25/MWh	$21/MWh
Marengo 2	$21/MWh	$17/MWh
Goodnoe Hills	$26/MWh	$23/MWh

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

A. Yes. As is the case for the February 2018 analysis, these project-by-project results do not reflect the potential value of RECs that will be generated by the incremental energy output from each facility.

FOOTE CREEK I

Q. Please describe the repowering of the Foote Creek I facility.

A. As discussed in the testimony of Mr. Hemstreet, the Foote Creek I wind facility was originally developed more than 20 years ago. Because of its age and design, repowering of Foote Creek I involves the removal of all existing wind turbine equipment, including towers, foundations, and energy collection system, and replacement with new equipment and energy collector circuits appropriately sized for the new equipment. Repowering at the Foote Creek I facility will result in the replacement of 68 existing small-capacity wind turbines with 13 modern wind turbines, representing approximately 46 MW of wind resource nameplate capacity.

Q. Why wasn't Foote Creek I included in your main economic analysis?

A. As discussed above, the scope of repowering the Foote Creek I facility is notably different than the other wind facilities. Moreover, unlike the other 12 wind facilities within the scope of the wind repowering project, PacifiCorp shared ownership of Foote Creek I with Eugene Water & Electric Board (EWEB). Further differentiating Foote Creek I from the other 12 wind facilities within the scope of the wind repowering project, Bonneville Power Administration (BPA) was purchasing 37 percent of the output from Foote Creek I via a power-purchase agreement (PPA) that was to terminate in April 2024. Taken together, it took additional time to engage in discussions with EWEB and BPA to determine whether the ownership structure and PPA could be modified to facilitate repowering the Foote Creek I wind facility. Ultimately, as Mr. Hemstreet describes in his testimony, PacifiCorp was able to clear the way for repowering by acquiring EWEB's ownership interest, terminating the PPA with BPA, and acquiring the master wind energy lease rights associated with the Foote Creek I site.

Q. When did PacifiCorp make the decision to repower Foote Creek I?

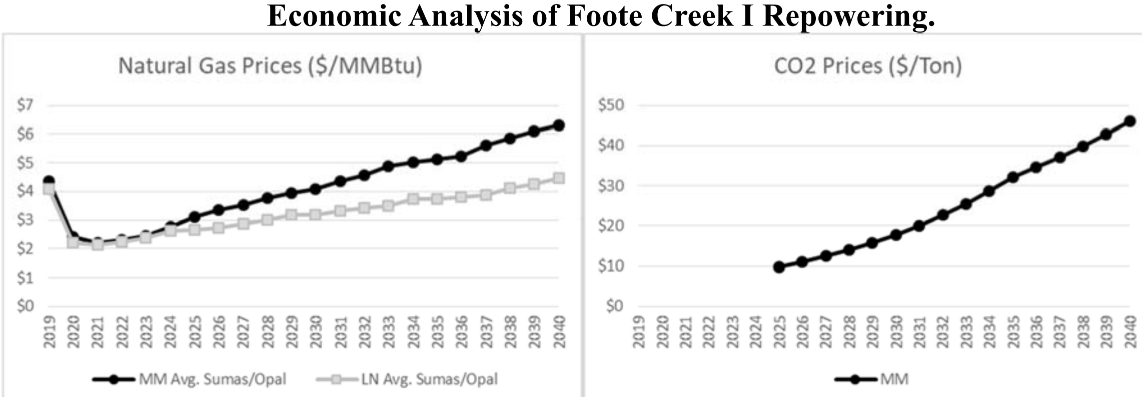
A. PacifiCorp made the decision to repower Foote Creek I in June 2019.

Q. Please summarize the economic analysis that supports the prudence of this decision.

A. PacifiCorp originally approved repowering Foote Creek I based on a June 11, 2019 economic analysis indicating that repowering would produce present-value net customer benefits ranging between \$3 million to \$46 million. This analysis included acquisition of EWEB's 21.21 percent ownership interest and termination of the PPA with BPA. This analysis did not include acquisition of the master wind energy lease rights associated with the Foote Creek I site.

The economic analysis was updated July 16, 2019, to reflect the acquisition of the master wind energy lease rights associated with the Foote Creek I site. This analysis used two price-policy scenarios, representing low and medium natural gas prices and zero and medium CO_2 price scenarios. The price-policy scenario that pairs medium natural gas prices with medium CO_2 prices is referred to as the "MM" scenario and the price-policy scenario that pairs low natural gas prices with a zero CO_2 price is referred to as the "LN" scenario. The natural gas and CO_2 price assumptions are summarized in Figure 7.

Figure 7. Price-Policy Assumptions used in the Economic Analysis of Foote Creek I Repowering.



My analysis shows that Foote Creek I will deliver net customer benefits in both price-policy scenarios through 2050, producing present-value net customer benefits ranging between \$6 million to \$48 million.

Q. Please explain how you conducted your analysis.

A. The methodology is consistent with the approach used to perform the economic analysis of the other 12 facilities within the scope of the wind repowering project. The system value of incremental wind energy in eastern Wyoming is calculated from two PaR simulations for a given price-policy scenario—one simulation with incremental wind energy and one simulation without incremental wind energy. I then converted the system value of incremental wind energy to a dollar-per-megawatt-hour value by dividing the change in annual system costs by the change in incremental wind energy for both price-policy scenarios through 2038. The value of wind energy is extended out through 2050 by extrapolating the system values calculated from modeled data over the 2030-2038 time frame. The assumed system value, expressed in dollars per megawatt-hour, is applied to the incremental energy output associated with Foote Creek I wind repowering.

Q. Please provide the results of your analysis.

A. Foote Creek I repowering is forecasted to provide significant net benefits for customers. Table 18 summarizes PVRR(d) benefits calculated from changes in system costs through 2050, inclusive of the cost of repowering. This table also presents the same information on a levelized dollar-per-megawatt-hour basis. Under the medium and low price-policy scenarios, nominal levelized net benefits are \$29/MWh and \$3/MWh, respectively. These results are consistent with the range of the net benefits associated with other wind repowering facilities, shown above in Tables 5 and 16.

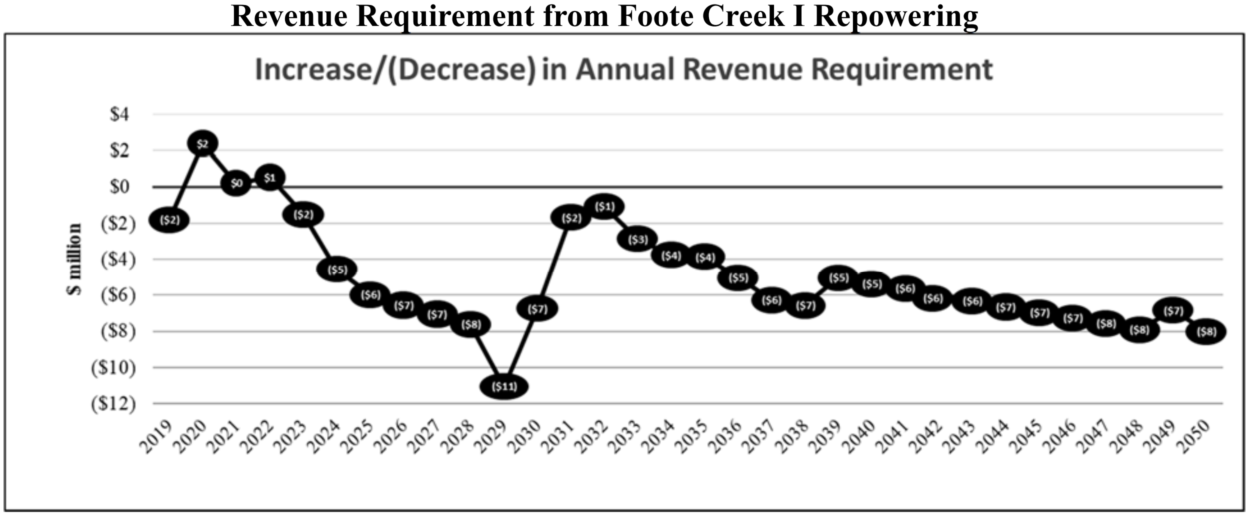
Table 18. Net Benefits from Foote Creek I Repowering

	PVRR(d) Net (Benefit)/Cost ($ million)	Nom. Lev. Net Benefit ($/MWh of Incremental Energy)
Medium Natural Gas, Medium CO_2	($48.2)	$29/MWh
Low Natural Gas, No CO_2	($5.6)	$3/MWh

Q. Have you demonstrated the estimated change in nominal annual revenue requirement from Foote Creek I repowering for the medium price-policy scenario?

A. Yes. Figure 8 reflects the change in nominal revenue requirement associated with project costs, including capital revenue requirement (*i.e.*, depreciation, return, income taxes, and property taxes), O&M expenses, the Wyoming wind-production tax, and production tax credits. The project costs are netted against system benefits as described above. Foote Creek I repowering reduces nominal revenue requirement in all but the first three years of its depreciable life.

Figure 8. (Reduction)/Increase in Total-System Annual Revenue Requirement from Foote Creek I Repowering



II. NEW WIND AND TRANSMISSION

Q. Please describe the new wind and transmission elements of Energy Vision 2020 included in this case.

A. By the end of 2020, PacifiCorp will add 1,150 MW of new wind resources in Wyoming. These resources are comprised of three facilities built by PacifiCorp, the 500 MW TB Flats I and II facilities and the 250 MW Ekola Flats project, and one facility that is a combined build-transfer agreement (BTA) and PPA, the 400 MW Cedar Springs facility (collectively, the Energy Vision 2020 Wind Projects). These facilities were carefully selected to maximize value to customers in the 2017R RFP, which was monitored by independent evaluators from both Oregon and Utah.

Because PacifiCorp's current transmission system in eastern Wyoming is operating at capacity, PacifiCorp is also building a new, 140-mile Gateway West transmission sub-segment—the 500 kV Aeolus-to-Bridger/Anticline transmission line, plus network upgrades—in Wyoming to enable this generation (collectively, Transmission Projects). As explained by Mr. Richard A. Vail, the line allows PacifiCorp to interconnect up to 1,510 MW of new capacity, relieving existing transmission constraints in southeastern Wyoming. The new line increases transfer capability westbound by approximately 950 MW.

Q. Please summarize your testimony in Section II.

A. PacifiCorp's economic analysis shows that the investments in the Combined Projects are prudent, useful, and in the public interest. The Energy Vision 2020 Wind Projects, which are enabled by the Transmission Projects, will generate PTCs for 10 years; produce zero-fuel-cost energy that will lower NPC; generate RECs, which can be sold in the market to create additional revenues that would lower net customer costs or be used to comply with state renewable portfolio standard targets; and help decarbonize PacifiCorp's resource portfolio, which will mitigate long-term risk associated with potential future state and federal policies targeting CO_2 emissions reductions from the electric sector.

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

The Combined Projects will produce customer benefits that significantly outweigh costs. The change in revenue requirement due to the Combined Projects was analyzed using two different IRP modeling tools across nine different scenarios, each with varying natural-gas and CO_2 price assumptions. For each of these scenarios, the PVRR(d) was calculated from system revenue requirement forecasts through 2050 (through the 30-year life of the Wind Projects), reflecting nominal capital revenue requirement from the Combined Projects, and from system revenue requirement forecasts over a 20-year period, where capital revenue requirement is levelized. This approach is the same basic methodology that was used to evaluate the wind repowering project discussed earlier in my testimony.

The Combined Projects show net PVRR(d) benefits of $174 million in the medium case through 2050, and benefits of $338 million in the medium case through 2036. In the 18 scenarios studied (nine each for the 2050 and 2036 analyses), 16 of 18 cases show net customer benefits.

The customer benefits from the Combined Projects increase substantially with higher natural-gas price assumptions and higher CO_2 price assumptions. These benefits conservatively do not assign any value to the RECs that will be generated by the Energy Vision 2020 Wind Projects. For every dollar assigned to the incremental RECs that will be generated by the Wind Projects, present-value benefits would improve for all scenarios by an additional $38 million when calculated from the change in system revenue requirement through 2050. When calculated from the change in system revenue requirement over a 20-year period, each dollar assigned to the incremental RECs from the Energy Vision 2020 Wind Projects would increase PVRR(d) benefits by $31 million.

Sensitivity analysis shows that substantial benefits of the Combined Projects persist when paired with PacifiCorp's plans to repower certain wind resources, which is the subject of Section I of my testimony.

2017 INTEGRATED RESOURCE PLAN

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

A. Yes. The 2017 IRP preferred portfolio included 1,100 MW of new wind resources located in Wyoming. This wind capacity is enabled by the Aeolus-to-Bridger/Anticline line, which is also included in the 2017 IRP preferred portfolio.

The new wind and Aeolus-to-Bridger/Anticline line are assumed to be placed in service by the end of 2020 so that the new wind resources can qualify for the full value of PTCs.

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

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

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

To assess these potential incremental benefits, PacifiCorp reviewed components of its Energy Gateway transmission project to identify specific sub-segments that could access additional new Wyoming wind resources. In performing this review, PacifiCorp looked at the transmission interconnection queue and determined that sub-segment D.2 (the Aeolus-to-Bridger/Anticline Line) of the Energy Gateway transmission project could access a sizable volume of new wind projects being developed in the Aeolus area. PacifiCorp then developed an initial, high-level cost estimate for the Aeolus-to-Bridger/Anticline Line that was used for an initial Aeolus-to-Bridger/Anticline sensitivity assuming 650 MW of incremental transfer capability and 900 MW of new Wyoming wind resources.

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

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

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

A. The initial sensitivity indicated that there could be economic benefits from aligning development of the Aeolus-to-Bridger/Anticline Line with new, PTC-eligible Wyoming wind resources. Based on the promising results from this initial sensitivity, PacifiCorp reviewed its initial, high-level assumptions to determine how refined inputs would affect potential benefits from the incremental new Wyoming wind resources and the Aeolus-to-Bridger/Anticline Line.

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

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

PacifiCorp also reviewed whether additional benefits from the wind enabled by the Aeolus-to-Bridger/Anticline Line could be quantified. PacifiCorp identified and quantified three additional value streams associated with its participation in the EIM, improved transmission reliability, and reduced transmission line losses. The results from this additional review and analysis were applied in the final 2017 IRP resource-portfolio screening process, where PacifiCorp conducted additional studies that considered analysis performed in earlier resource-portfolio screening stages.

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

A. In earlier stages of its resource-portfolio screening process, PacifiCorp developed a wind repowering sensitivity, where certain existing wind resources qualify for an additional 10 years of PTCs after they are upgraded with modern equipment. The wind repowering project, discussed in Section I of my testimony, showed significant net customer benefits across a range of assumptions related to forward market prices and federal CO_2 policy based on the Clean Power Plan. Considering the significant customer benefits associated with the wind repowering project, PacifiCorp combined its refined assumptions for incremental new Wyoming wind and the Aeolus-to-Bridger/Anticline Line in a study that included wind repowering.

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

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

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

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

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

- By January 2018, complete final shortlist bid evaluation, seek acknowledgment of the final shortlist from the Public Utility Commission of Oregon, and seek approval of winning bids from the Utah Public Service Commission.

- By March 2018, receive CPCN approval from the Wyoming Public Service Commission.

- Complete construction of new wind projects by December 31, 2020.

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

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

> By December 31, 2020, PacifiCorp will build the 140-mile, 500 kV transmission line running from the Aeolus substation near Medicine Bow, Wyoming, to the Jim Bridger power plant (a sub-segment of the Energy Gateway West transmission project). This includes pursuing regulatory review and approval as necessary.
>
> - June-July 2017, file a CPCN application with the Wyoming Public Service Commission.
>
> - By March 2018, receive conditional CPCN approval from the Wyoming Public Service Commission pending acquisition of rights of way.
>
> - By December 2018, obtain Wyoming Industrial Siting permit and issue EPC limited notice to proceed.
>
> - Complete construction of the transmission line by December 31, 2020.

Q. Did PacifiCorp address the Combined Projects in its 2019 IRP?

A. All resource portfolios developed for the 2019 IRP include the Combined Projects, which are under construction. New resource acquisitions were evaluated assuming the Combined Projects will be placed in service by the end of 2020.

2017R RFP

Q. When did PacifiCorp issue the 2017R RFP called for in the 2017 IRP?

A. PacifiCorp is subject to resource procurement requirements in Oregon under Competitive Bidding Guidelines established by Oregon Commission Order No. 06-446 in Docket No. UM 1182, and in Utah under Utah Code Ann. § 54-17-201 *et. seq.* PacifiCorp issued the 2017R RFP on September 27, 2017, after it was approved by the Utah Commission on September 22, 2017, and the Oregon Commission on September 27, 2017.

Q. Was the scope of the 2017R RFP modified before it was issued to include non-Wyoming wind projects?

A. Yes. PacifiCorp's original RFP was limited to Wyoming wind resources. In response to feedback from the Utah independent evaluator and other stakeholders, the Company expanded the 2017R RFP to allow bids from non-Wyoming wind projects.

Q. In response to the Utah Commission's approval order, did the Company decide to issue a solar RFP to run concurrently with the 2017R RFP?

A. Yes. In its order approving the 2017R RFP, the Utah Commission suggested, but did not require, a modification to expand the 2017R RFP to solicit solar resource bids. To maintain the 2017R RFP schedule while addressing the Utah Commission's suggestion, the Company issued a separate solicitation process for solar resources, the 2017S RFP, on November 15, 2017. The 2017S RFP allowed the Company to: (1) evaluate how solar resource bids might impact the economic analysis of bids selected to the final shortlist in the 2017R RFP without delaying the schedule for the

2017R RFP; and (2) explore whether new solar resource opportunities might provide all-in economic benefits for customers.

Q. Please describe the key milestones in the 2017R RFP.

A. First, PacifiCorp received initial bids in October 2017. The 2017R RFP was well received by the market, with 5,219 MW of new wind resource capacity bid into the 2017R RFP (4,624 MW of Wyoming wind and 595 MW of non-Wyoming wind).

Second, PacifiCorp evaluated bids and selected the initial shortlist in November 2017. The establishment of the final shortlist was delayed by the need for refreshed bids to account for the enactment of the Tax Cuts and Jobs Act (TCJA) in December 2017.

Third, PacifiCorp announced its final shortlist in January 2018. The final shortlist consisted of four new wind projects located in Wyoming with a total capacity of 1,170 MW including three of the Company's benchmark facilities (TB Flats I and II, now combined as a single 500 MW project, and the 109 MW McFadden Ridge II project), and two new facilities: Uinta, a BTA totaling 161 MW, and Cedar Springs, one-half BTA and one-half PPA, for a total of 400 MW.

Fourth, PacifiCorp updated the final shortlist in February 2018 after completing its interconnection-restudy process. PacifiCorp initially developed the final shortlist based on economic analysis of the bids without consideration of interconnection queue position. Based on the results of the interconnection restudies, PacifiCorp removed the McFadden Ridge II benchmark because it could not be interconnected with just the addition of the Aeolus-to-Bridger/Anticline transmission line. The updated final shortlist added the Ekola Flats benchmark bid and increased the total capacity in the updated final shortlist to 1,311 MW. In its restudy process, PacifiCorp confirmed the Aeolus-to-Bridger/Anticline Line will enable interconnection of up to 1,510 MW of new wind capacity within the constrained area of PacifiCorp's transmission.

Q. Please summarize the role of the independent evaluators who monitored the 2017R RFP.

A. The 2017R RFP was overseen by two independent evaluators—one appointed and retained by the Utah Commission, and one appointed by the Oregon Commission and retained by PacifiCorp. In accordance with the statutes, rules, and policies in Utah and Oregon, the independent evaluator is an *independent* expert appointed and managed by the Utah Commission (not PacifiCorp) to ensure that the RFP process was conducted in a fair and unbiased manner and the final shortlist projects are reasonable and consistent with the modeling results used to evaluate bids.

In the 2017R RFP, both independent evaluators were involved from the beginning—providing feedback and recommendations regarding the design and content of the 2017R RFP and actively participating in every stage of the RFP. For its part, PacifiCorp ensured that the independent evaluators had complete and unrestricted access to all information related to the 2017R RFP and kept both independent evaluators informed of developments as they occurred.

Q. Did the independent evaluators provide an assessment of PacifiCorp's benchmark resources bid into the 2017R RFP (*i.e.*, TB Flats I and II, Ekola Flats, and McFadden Ridge II)?

A. Yes. Because the 2017R RFP included benchmark resources, both independent evaluators provided detailed assessments of the benchmark bids to ensure that they were reasonable and would not bias the solicitation in favor of utility-owned resources.[1] The benchmark review process occurred before any other bids were received to provide additional assurance that the benchmarks were not provided an unfair advantage.

Q. Did the independent evaluators confirm the reasonableness of the benchmark bids?

A. Yes. The Utah independent evaluator concluded that: (1) PacifiCorp provided detailed information related to the benchmarks that exceeded industry standards; (2) cost estimates were reasonable; and (3) the review, assessment, and scoring of the benchmark resources was conducted in a fair and equitable manner with no outward perception of bias.[2]

The Oregon independent evaluator also conducted a thorough assessment of the benchmarks, noting that when "assessing a utility's own bids in response to the RFP, our greatest concern is that the utility will incorporate cost estimates that have been aggressively estimated and do not characterize the costs of the project

[1] Oregon's final independent evaluator report, issued in February 2018 (Oregon IE Report), is available at: https://edocs.puc.state.or.us/efdocs/HAH/um1845hah16913.pdf;
Utah's final independent evaluator report, also issued in February 2018 (Utah IE Report), is available at: https://pscdocs.utah.gov/electric/17docs/1703523/300621IERedacFinRep2-27-2018.pdf.

[2] Utah IE Report at 44-45.

accurately."[3] To make its assessment, the Oregon independent evaluator "looked at a detailed breakdown of each of the benchmarks costs to determine if any items have been improperly omitted from the cost calculation, and at overall capital cost levels by comparing them to publicly-available data on recent wind generation capital costs."[4] This "comparison provided a measure of the overall reasonableness of the Benchmark capital costs and capacity factors."[5] The Oregon independent evaluator ultimately found that the benchmarks were acceptable based on three items:

- First, the benchmarks were not deliberately underpriced through omission of any capital cost components.
- Second, the benchmark capital and operating costs appeared reasonable when compared with public data on U.S. wind projects.
- Third, the capacity factors of the benchmarks were reasonable when compared with public data and were supported by credible third-party analysis.[6]

Q. Did the independent evaluators provide any overall conclusions related to the 2017R RFP?

A. Yes. The Utah independent evaluator supported the final shortlist projects based on the following conclusions:

- The 2017R RFP was fair, reasonable, and generally in the public interest.[7]
- The bid evaluation and selection processes were designed to lead to the acquisition of wind-generated electricity at the lowest reasonable cost based on the detailed state-of-the-art portfolio evaluation methodology used, the steps taken to achieve comparability between utility cost-of-service resources and third-party firm priced bids, the flexibility afforded bidders via a range

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[3] Oregon IE Report at 10.
[4] *Id.*
[5] *Id.*
[6] *Id.* at 10–11.
[7] Utah IE Report at 70.

of eligible resource alternatives, and the attempt to allow for equal terms for PPA and BTA resources.[8]

- PacifiCorp's modeling demonstrates that the Combined Projects "should result in significant savings for customers." Further, because PTCs will flow through to customers in the first 10 years, the "near-term benefits to customers should be significant."[9]

The Oregon independent evaluator also recommended that the Oregon Commission approve PacifiCorp's final shortlist based on the following conclusions:

- The selected bids represent the top offers that are viable under current transmission planning assumptions and provide the greatest benefits to ratepayers.

- The selected bids represent the best viable options from a competitive perspective, based on the 59 bid options presented.

- The IE's analysis confirmed that the selected bids were reasonably priced and, while not the lowest-cost offers, were the lowest-cost offers that were viable under current transmission planning assumptions. The independent evaluator's analysis included its own cost models for each bid option and a review of PacifiCorp's models.

- The IE took special care to confirm the selection of PacifiCorp's benchmark resources. The independent evaluator confirmed the accuracy of the benchmark costs and scoring. The independent evaluator noted that the benchmark bids were disciplined by the fact that a third-party bidder submitted a competing offer for a BTA for benchmark projects.

- The IE confirmed that the 2017R RFP aligns with the 2017 IRP.[10]

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[8] Utah IE Report at 71.
[9] Utah IE Report at 83.
[10] Oregon IE Report at 2-3.

ENERGY VISION 2020 CPCN/PRE-APPROVAL FILINGS

Q. Did PacifiCorp seek a certificate of public convenience (CPCN) for the Combined Projects from the Wyoming Commission?

A. Yes. Because the Combined Projects are being constructed in Wyoming, PacifiCorp filed an application for a CPCN at the Wyoming Commission in June 2017.

Q. Did the Wyoming Commission approve PacifiCorp's CPCN application?

A. Yes, in April 2018, the Wyoming Commission approved the CPCN based on a stipulation among several parties. In the stipulation, PacifiCorp agreed to remove the 161 MW Uinta facility from the final shortlist. This reduced the total capacity of the Wind Projects from 1,311 MW to 1,150 MW. PacifiCorp updated its February 2018 economic analysis to reflect this change.

Q. Did PacifiCorp request and receive approval for the Combined Projects in other states?

A. Yes. PacifiCorp filed for a CPCN in Idaho. In Utah, PacifiCorp requested approval under Utah Code Ann. § 54-17-302 for the Company's "significant energy resource decision" to acquire the Wind Projects; it also requested approval under Utah Code Ann. § 54-17-402 for its "resource decision" to construct the Transmission Projects. The Company updated both applications to remove the Uinta facility based on the stipulation in Wyoming. The Utah and Idaho Commissions granted the applications in June and July 2018, respectively.

MODELING METHODOLOGY

Q. Please describe the chronology of PacifiCorp's analyses of the Combined Projects.

A. PacifiCorp's initial economic analysis of the Combined Projects was in the 2017 IRP. The Company updated this analysis in June 2017 when it filed for CPCNs and pre-approval in Wyoming, Utah and Idaho. After the initial final shortlist was selected, PacifiCorp updated its analysis in January 2018 to reflect the winning bids, which at the time included McFadden Ridge II. Following the completion of the interconnection restudies, in February 2018, PacifiCorp updated its economic analysis to replace McFadden Ridge II with Ekola Flats. After the stipulation removing Uinta from the Combined Projects, PacifiCorp adjusted its February 2018 analysis to reflect this change.

Q. What economic analysis did the Company rely upon in deciding to move forward with its investment in the Combined Projects?

A. PacifiCorp relied upon its economic analysis from February 2018, adjusted to remove the Uinta facility, to make its decision to move forward with the Combined Projects.

Q. In Section I of your testimony, you present an August 2018 update to the wind repowering analysis. Why is there not an August 2018 update to the analysis of the Combined Projects?

A. The August 2018 wind repowering analysis was primarily produced to capture updated cost-and-performance estimates for the Leaning Juniper wind facility, which could be implemented at a lower cost and with higher incremental energy output relative to what was originally assumed. To ensure the updated economics of

Leaning Juniper repowering could be compared with other repowering projects, the economic analysis for each facility was updated. This analysis confirmed that the updated cost-and-performance assumptions for Leaning Juniper would improve expected customer benefits and the economics of the other wind facilities within the scope of the wind repowering project did not materially change. In contrast, there were no comparable changes to the expected cost-and-performance assumptions for any of the Energy Vision 2020 Wind Projects that would necessitate triggering an updated analysis.

System Modeling Methodology

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

A. As with the wind repowering project, PacifiCorp relied upon the modeling tools used to develop resource portfolios in its 2017 IRP to refine its analysis of the Combined Projects. These IRP modeling tools, described in Section I of my testimony, calculate system PVRR by identifying least-cost resource portfolios and dispatching system resources over a 20-year forecast period (2017–2036). Net customer benefits are calculated as the PVRR(d) between two simulations of PacifiCorp's system. One simulation includes the Combined Projects, and the other simulation excludes the Combined Projects.

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

A. Yes. As with the wind repowering project, PacifiCorp analyzed the Combined Projects under a range of price-policy assumptions regarding wholesale market prices and CO_2 policy. Each pair of model simulations—with and without the Combined Projects, in both the SO model and PaR—was analyzed under each combination of these price-policy assumptions.

PacifiCorp also completed sensitivity studies to assess how certain factors affect the net benefits of the Combined Projects. The first sensitivity compares the Combined Projects to potential solar resources, based on bids received in the 2017S RFP. The second sensitivity quantifies how the net benefits of the Combined Projects are affected when paired with the wind repowering project.

Q. What assumptions did PacifiCorp use in its economic analysis of the Combined Projects in February 2018?

A. The models reflect: (1) cost-and-performance assumptions for the Wind Projects consistent with the winning bids selected to the 2017R RFP final shortlist; (2) the latest load-forecast projections; (3) the latest price-policy scenario assumptions; and (4) changes in federal tax rate for corporations under the TCJA.

Q. Please describe the cost-and-performance estimates for the Energy Vision 2020 Wind Projects in the February 2018 economic analysis.

A. The February 2018 economic analysis includes the capital costs associated with the winning bids, the costs associated with the Cedar Springs PPA, and updated net capacity factors. This economic analysis also captures terminal-value benefits from BTA and EPC-benchmark bids, where the Company retains control of the site at the end of the asset life. These benefits were considered in the 2017R RFP bid-selection process, consistent with the bid-evaluation methodology described in the RFP, and therefore, they are applied in the economic analysis.

Q. Please describe the load forecast and price-policy assumptions included in the February 2018 economic analysis.

A. The economic analysis uses PacifiCorp's load forecast completed in the summer of 2017. PacifiCorp used the same price-policy assumptions for the February 2018 analysis of the Combined Projects that it used for the February 2018 analysis of the wind repowering project. These assumptions are described in Section I of my testimony.

Q. Please describe the updated federal tax rate for corporations included in the updated economic analysis.

A. PacifiCorp's analysis assumes a 21-percent federal income tax rate. Based on an assumed net state income tax rate of 4.54 percent, the effective combined federal and state income tax rate used in the updated analysis is 24.587 percent.

Q. How did PacifiCorp apply federal PTC benefits in its system modeling using the SO model and PaR configured to forecast system costs through 2036?

A. When establishing the 2017R RFP final shortlist, PacifiCorp applied PTC benefits for applicable bids (BTAs and benchmark-EPC bids) on a nominal basis rather than on a levelized basis. This approach better reflects how the federal PTC benefits for these bids will flow through to customers and aligns the treatment of federal PTC benefits in the system modeling results extending out through 2036 with the nominal revenue requirement results extending out through 2050. It also ensures the 2017R RFP bid selections from the SO model more accurately reflect the difference in how BTA and benchmark-EPC bids are expected to impact customer rates.

Q. Did PacifiCorp apply revenue requirement associated with capital costs on a levelized basis in its system modeling using the SO model and PaR configured to forecast system costs through 2036?

A. Yes. As discussed below, when setting rates, revenue requirement from capital costs is depreciated over the book life of the asset, effectively spreading the cost of capital investments over the life of the asset. Because revenue requirement from capital projects is spread over the life of the asset in rates, these costs continue to be treated as a levelized cost in the SO model and PaR simulations.

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

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

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

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

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

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

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

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

A. Yes. As with the wind repowering project, the more efficient use of transmission that is expected with growing participation in the EIM was captured in the economic analysis of the Combined Projects by increasing the transfer capability between the east and west sides of PacifiCorp's system by 300 MW (from the Jim Bridger plant to south-central Oregon). The ability to more efficiently use intra-hour transmission from a growing list of EIM participants is not driven by the Combined Projects; however, this increased connectivity provides the opportunity to move low-cost incremental energy out of transmission-constrained areas of Wyoming.

Annual Revenue Requirement Modeling Methodology

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

A. Yes. The system PVRR from the SO model and PaR was calculated from an annual stream of forecasted revenue requirement over a 20-year time frame, consistent with the planning period in the IRP. The annual stream of forecasted revenue requirement captures nominal revenue requirement for non-capital items (*i.e.*, NPC, fixed operations and maintenance, etc.) and levelized revenue requirement for capital expenditures. To estimate the annual revenue-requirement impacts of the Combined Projects, capital costs for the Wind Projects and the Transmission Projects need to be considered in nominal terms (*i.e.*, not levelized).

Q. Why is the capital revenue requirement used in the calculation of the 2036 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.

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

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

These data are disaggregated to isolate the estimated annual NPC benefits, other non-NPC variable-cost benefits (*i.e.*, variable 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 costs for the Combined Projects, including nominal capital revenue requirement and PTCs, are added back in with the annual system net benefits caused by the Combined Projects.

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

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

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

A. PacifiCorp assumed a 62-year life for the Transmission Projects. The Transmission Projects will continue to provide system benefits well beyond 2050 when the Wind Projects are fully depreciated. These additional benefits are not reflected in PacifiCorp's economic analysis.

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

A. PacifiCorp followed the same approach it used to assess the wind repowering projects through 2050, described in Section I of my testimony.

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

A. Yes.

SYSTEM MODELING PRICE-POLICY RESULTS

Q. Please summarize the PVRR(d) results calculated in February 2018 from the SO model and PaR through 2036.

A. Table 19 summarizes the PVRR(d) results for each price-policy scenario. The PVRR(d) between cases with and without the Combined Projects, reflecting the updated final shortlist from the 2017R RFP, 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 updated SO Model PVRR(d) and PaR Stochastic Mean PVRR(d) results shown in the table are provided as Exhibit No. RTL-6.

Table 19. February 2018 SO Model and PaR PVRR(d) (Benefit)/Cost of the Combined Projects ($ million)

Price-Policy Scenario	Updated Final Shortlist		
	SO Model PVRR(d)	**PaR Stochastic Mean PVRR(d)**	**PaR Risk-Adjusted PVRR(d)**
Low Gas, Zero CO_2	($185)	($150)	($156)
Low Gas, Medium CO_2	($208)	($179)	($188)
Low Gas, High CO_2	($370)	($337)	($355)
Medium Gas, Zero CO_2	($377)	($319)	($334)
Medium Gas, Medium CO_2	($405)	($357)	($386)
Medium Gas, High CO_2	($489)	$(448)	($469)
High Gas, Zero CO_2	($699)	($568)	($596)
High Gas, Medium CO_2	($716)	($603)	($633)
High Gas, High CO_2	($781)	($694)	($728)

Over a 20-year period, the Combined Projects reduce 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, when applying medium natural gas, medium CO_2 price-policy assumptions, the PVRR(d) net benefits range between $357 million, when derived from PaR stochastic-mean results, and $405 million, when derived from SO model results.

Q. What is the potential upside to these PVRR(d) results associated with REC revenues?

A. The PVRR(d) results presented in Table 19 do not reflect the potential value of RECs generated by the incremental energy output from the updated final shortlist projects. Accounting for the performance estimates from the updated final shortlist projects, customer benefits for all price-policy scenarios would improve by approximately

$34 million for every dollar assigned to the incremental RECs that will be generated from the winning bids through 2036. Quantifying the potential upside associated with incremental REC revenues is simply intended to communicate that the net benefits from the winning bids could improve if the incremental RECs can be monetized in the market or otherwise used to offset higher cost purchases required to meet state renewable portfolio standard targets.

Q. Did you calculate the potential upside to these PVRR(d) results associated with reduced O&M costs?

A. Yes. Projects with large wind turbines are expected to require less O&M costs because there are fewer turbines on a given site. The default O&M assumptions applied to BTA and benchmark-EPC bids in the economic analysis are based on the Company's experience in operating and maintaining the existing fleet of owned-wind facilities, and do not reflect expected cost savings associated with operating and maintaining wind facilities proposing to use larger wind turbines. If the O&M cost elements applicable to the larger-turbine equipment are reduced by 42 percent, which is equivalent to an approximately 18-percent reduction in total O&M costs, beyond the proposed O&M agreement period, customer benefits calculated through 2036 for all price-policy scenarios would improve by approximately $19 million.

Q. Is there additional upside to the net benefits shown in Table 19?

A. Yes. The Company's analysis conservatively calculates net benefits by comparing a case with the Combined Projects against a case without the Combined Projects. As discussed by Mr. Vail, the Aeolus-to-Bridger/Anticline Line has been an integral component of PacifiCorp's long-term transmission plan for some time and it is unlikely that this investment would never be needed. The economic benefits would increase substantially if the case with the Combined Projects were compared to a case where the Aeolus-to-Bridger/Anticline line were added to the system at a later date. Further, the CO_2 price assumptions used in the updated 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.

REVENUE REQUIREMENT MODELING PRICE-POLICY RESULTS

Q. Please summarize the February 2018 PVRR(d) results calculated from the change in annual revenue requirement through 2050.

A. Table 20 summarizes the updated PVRR(d) results for each price-policy scenario calculated from the change in annual nominal revenue requirement through 2050. The annual data over the period 2017 through 2050 that was used to calculate the updated PVRR(d) results shown in the table are provided as Exhibit No. RTL-7.

Table 20. February 2018 Nominal Revenue Requirement PVRR(d) (Benefit)/Cost of the Combined Projects ($ million)

Price-Policy Scenario	Updated Final Shortlist
Low Gas, Zero CO_2	$184
Low Gas, Medium CO_2	$127
Low Gas, High CO_2	($147)
Medium Gas, Zero CO_2	($92)
Medium Gas, Medium CO_2	($167)
Medium Gas, High CO_2	($304)
High Gas, Zero CO_2	($448)
High Gas, Medium CO_2	($499)
High Gas, High CO_2	($635)

When system costs and benefits from the Combined Projects are extended out through 2050, covering the full depreciable life of the owned-wind projects included in the updated 2017R RFP final shortlist, the Combined Projects reduce customer costs in seven out of nine price-policy scenarios. Customer net benefits range from $92 million in the medium natural-gas, zero CO_2 price-policy scenario to $635 million in the high natural gas, high CO_2 price-policy scenario. Under the central price-policy scenario, when applying medium natural gas, medium CO_2 price-policy assumptions, the PVRR(d) benefits of the Combined Projects are $167 million. The Combined Projects provide significant customer benefits in all price-policy scenarios, and the net benefits are unfavorable only when low natural-gas prices are paired with zero or medium CO_2 prices. These results show that upside benefits far outweigh downside risks.

Q. Is there additional potential upside to these PVRR(d) results associated with REC revenues?

A. Yes. The PVRR(d) results presented in Table 20 do not reflect the potential value of RECs generated by the incremental energy output from the Energy Vision 2020 Wind Projects. Accounting for the performance estimates from the updated final shortlist projects, customer benefits for all price-policy scenarios would improve by approximately $43 million for every dollar assigned to the incremental RECs that will be generated from the winning bids through 2050.

Q. Is there additional potential upside to these PVRR(d) results associated with reduced O&M costs?

A. Yes. As discussed above, the Company anticipates O&M costs for those projects that will install larger-turbine equipment to be lower than what has been reflected in the updated economic analysis. Accounting for these cost savings, customer benefits for all price-policy scenarios would improve by approximately $31 million when calculated from projected operating costs through 2050.

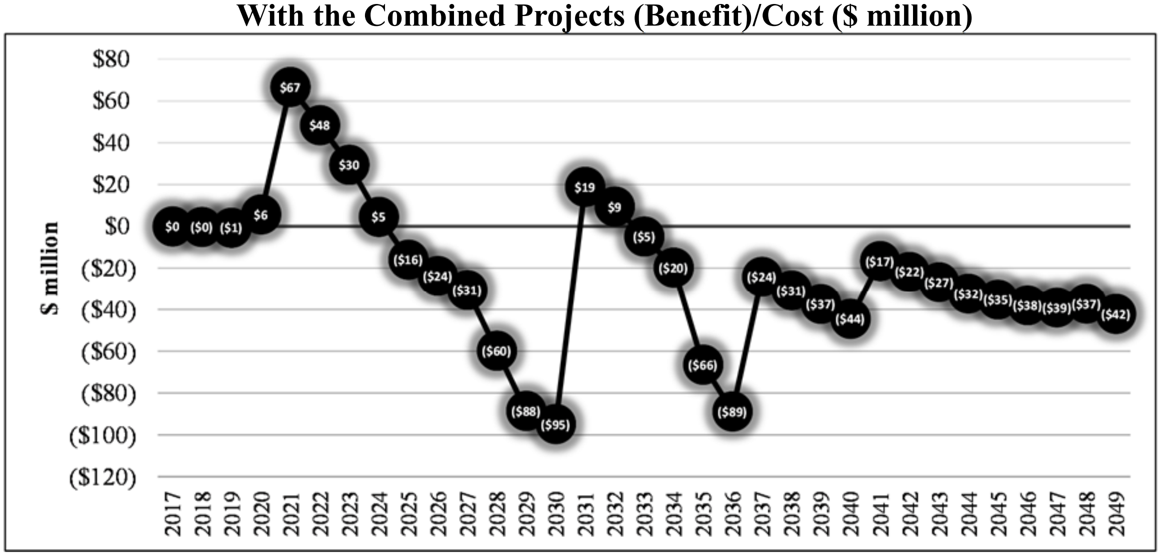
Q. Is there additional potential upside to these PVRR(d) results shown in Table 20?

A. Yes. As noted earlier, the economic benefits would increase substantially if the case with the Combined Projects were compared to a case where the Aeolus-to-Bridger/Anticline line were added to the system at a later date. Moreover, the updated CO_2 price assumptions used in the updated 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 Combined Projects.

A. Figure 9 shows the change in nominal revenue requirement due to the Combined Projects 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 February 2018 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 system impacts from the Combined Projects, reflecting the change in NPC, emissions, non-NPC variable costs, and system fixed costs that are affected by, but not directly associated with, the Combined Projects.

Figure 9. February 2018 Total-System Annual Revenue Requirement With the Combined Projects (Benefit)/Cost ($ million)



The Combined Projects produce net benefits in 23 years out of the 30 years that the proposed owned-wind resources selected to the 2017R RFP final shortlist are assumed to operate. The year-on-year reduction in net benefits from 2036 to 2037 is driven by the Company's conservative approach to extrapolate benefits from 2037 through 2050 based on modeled results from the 2028-through-2036 time frame. This leads to an abrupt reduction in the benefits in 2037, and a subsequent year-on-year reduction to net benefits, which breaks from the trend observed in the model results over the 2035-to-2036 time frame. This extrapolation methodology is conservative because it results in project benefits not matching the levels observed in the model results for 2036 until 2047.

SOLAR SENSITIVITY

Q. Did PacifiCorp include a solar sensitivity in its February 2018 analysis?

A. Yes. The solar sensitivity analysis reflects the updated final shortlist from the 2017R RFP and best-and-final pricing supplied by bidders participating in the 2017S RFP on February 1, 2018.

Q. Please describe the sensitivity studies that analyzed the impact of the solar bids received in the 2017S RFP on the economics of the Combined Projects.

A. The Company's solar sensitivity analysis used the SO model and PaR simulations to determine the PVRR(d) based on two model runs—one with solar PPA bids and the Combined Projects and one with solar PPA bids but without the Combined Projects.

Q. What were the results of the solar sensitivity where solar PPA bids are assumed to be pursued in lieu of the Combined Projects?

A. Table 21 summarizes PVRR(d) results for the solar sensitivity where solar PPA bids are assumed to be pursued without any investments in the Combined Projects. 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 benchmark study in which the Combined Projects were evaluated without solar PPA bids.

Table 21. February 2018 Solar Sensitivity with Solar PPAs Included in lieu of the Combined Projects (Benefit)/Cost ($ million)

	Sensitivity PVRR(d)	Benchmark PVRR(d)	Change in PVRR(d)
Medium Gas, Medium CO_2			
SO Model	($343)	($405)	$61
PaR Stochastic Mean	($228)	($357)	$129
PaR Risk Adjusted	($237)	($386)	$149
Low Gas, Zero CO_2			
SO Model	($196)	($185)	($11)
PaR Stochastic Mean	($139)	($150)	$11
PaR Risk Adjusted	($145)	($156)	$11

In this sensitivity, the SO model selects 1,122 MW of solar PPA bids in the low natural gas, zero CO_2 price-policy scenario and 1,419 MW of solar PPA bids in the medium natural gas, medium CO_2 price-policy scenario. All the selected solar PPA bids are for projects located in Utah.

In the medium natural gas, medium CO_2 price-policy scenario, a portfolio with the Combined Projects delivers greater customer benefits relative to a portfolio that adds solar PPA bids without the Combined Projects. Customer benefits are greater when the resource portfolio includes the Combined Projects without solar PPA bids by $149 million in the medium natural gas, medium CO_2 price-policy scenario based on the risk-adjusted PaR results. In the low natural gas, zero CO_2 price-policy scenario, the portfolio with the Combined Projects delivers slightly greater customer benefits relative to a portfolio that adds solar PPA bids without the Combined Projects when modeled in PaR, and slightly lower customer benefits when analyzed with the SO model. The decrease in net benefits in the solar PPA portfolio is $11 million based on the risk-adjusted PaR results.

When analyzed without the Combined Projects, the solar PPA bids produce net customer benefits that are lower than the benefits expected from the Combined Projects in the medium natural gas, medium CO_2 price-policy scenario. While the sensitivity with a portfolio containing solar PPAs without the Combined Projects produces PVRR(d) results that are similar to the PVRR(d) results with only the Combined Projects in the low natural-gas, zero CO_2 price-policy scenario, both portfolios deliver customer benefits. This sensitivity did not support an alternative resource procurement strategy to pursue solar PPA bids in lieu of the Combined Projects. This would leave the significant benefits from the Combined Projects, which include building a much-needed transmission line, on the table.

Q. What were the results of the solar sensitivity where solar PPA bids are pursued with the Combined Projects?

A. Table 22 summarizes PVRR(d) results for the solar sensitivity where solar PPA bids are assumed to be pursued along with the proposed investments in the Combined Projects. 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 benchmark study in which the Combined Projects were evaluated without solar PPA bids.

Table 22. February 2018 Solar Sensitivity with Solar PPAs Included With the Combined Projects (Benefit)/Cost ($ million)

	Sensitivity PVRR(d)	Benchmark PVRR(d)	Change in PVRR(d)
Medium Gas, Medium CO_2			
SO Model	($647)	($405)	($242)
PaR Stochastic Mean	($519)	($357)	($163)
PaR Risk Adjusted	($543)	($386)	($157)
Low Gas, Zero CO_2			
SO Model	($312)	($185)	($127)
PaR Stochastic Mean	($250)	($150)	($100)
PaR Risk Adjusted	($259)	($156)	($103)

In this sensitivity, the SO model continues to choose the winning bids included in the updated 2017R RFP final shortlist as part of the least-cost bid portfolio. In addition to these wind resource selections, the SO model selects 1,042 MW of solar PPA bids in the low natural gas, zero CO_2 price-policy scenario and 1,419 MW of solar PPA bids in the medium natural gas, medium CO_2 price-policy scenario. Again, all the selected solar PPA bids are for projects located in Utah.

When the solar PPAs are assumed to be pursued in addition to the Combined Projects, total net customer benefits increase. This result is consistent with PacifiCorp's expectation that cost-effective solar opportunities would not displace the Combined Projects but would only potentially add to incremental resource procurement opportunities that might provide net customer benefits.

WIND-REPOWERING SENSITIVITY

Q. Please explain PacifiCorp's February 2018 sensitivity analysis related to the wind repowering project.

A. The wind repowering sensitivity reflects the updated final shortlist and cost-and performance estimates for the wind repowering project as of February 2018. Table 23 summarizes PVRR(d) results for this wind-repowering sensitivity. 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 benchmark study in which the Combined Projects were evaluated without wind repowering.

Table 23. Wind-Repowering Sensitivity (Benefit)/Cost ($ million)

	Sensitivity PVRR(d)	Benchmark PVRR(d)	Change in PVRR(d)
Medium Gas, Medium CO_2			
SO Model	($608)	($405)	($204)
PaR Stochastic Mean	($541)	($357)	($184)
PaR Risk Adjusted	($567)	($386)	($181)
Low Gas, Zero CO_2			
SO Model	($334)	($185)	($149)
PaR Stochastic Mean	($281)	($150)	($131)
PaR Risk Adjusted	($295)	($156)	($138)

In the February 2018 wind-repowering sensitivity, customer benefits increase significantly when the wind repowering project is implemented with the Combined Projects 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 also increase, if both the wind-repowering project and the Combined Projects are completed.

ADJUSTED ECONOMIC ANALYSIS WITHOUT UINTA FACILITY

Q. Please summarize the cost-and-performance attributes of the Wind Projects without Uinta.

A. With removal of the Uinta project, the total in-service capital cost for the remaining Energy Vision 2020 Wind Projects is approximately $[redacted] billion, with a per-unit capital cost of $[redacted]/kW. In aggregate, the Energy Vision 2020 Wind Projects are expected to operate at a capacity-weighted average annual capacity factor of [redacted] percent.

Q. What is the nominal value of PTCs relative to the in-service capital cost of the Energy Vision 2020 Wind Projects without Uinta?

A. Over the first 10 years of operation, the Energy Vision 2020 Wind Projects that will be owned by PacifiCorp will generate over $1.2 billion in PTC benefits, which is nearly 103 percent of the in-service capital for these wind facilities.

Q. Did PacifiCorp update the February 2018 economic analysis of the Combined Projects based on the removal of the Uinta project?

A. Yes. First, PacifiCorp performed a spreadsheet analysis to estimate the high-level economic impact of removing the Uinta project. This spreadsheet analysis was performed for all nine price-policy scenarios previously described in my testimony. Consistent with the Company's previous economic analysis, these results are based on the methodology used in the Company's IRP through 2036 and using nominal revenue requirement projections through 2050.

Q. Please describe how you performed the high-level spreadsheet analysis.

A. Using data from the February 2018 economic analysis, I calculated the system benefits, including the Uinta Project, on a dollar-per-MWh basis for each price-policy scenario. I then multiplied these results by the expected generation from the Uinta project to estimate the annual system benefits associated with the Uinta project in total dollars. These system-benefit estimates were then netted against the same project-specific costs for the Uinta facility that were used in the February 2018 economic analysis. This calculation results in an estimate of the marginal net benefit or cost of removing the Uinta project for each price-policy scenario.

Q. Did you also update the February 2018 economic analysis using PacifiCorp's models?

A. Yes. I also re-ran PacifiCorp's IRP models to remove Uinta under the medium natural gas, medium CO_2 and low natural gas, zero CO_2 price-policy scenarios.

Q. Did you update any of the other inputs used in the analysis?

A. No. Other than removing Uinta, all the other inputs used in the economic analysis are the same as the inputs used in the February 2018 analysis.

Q. What is the high-level estimate of the economic impact of removing Uinta based on results through 2036?

A. Table 24 reports the high-level estimate of the economic impact of removing Uinta based on the results through 2036. These PVRR(d) results are shown alongside the results summarized in my February 2018 economic analysis. The difference between the original results that include Uinta and the high-level estimates without Uinta are an indicator of the marginal net benefit or cost of the Uinta project.

Table 24. Estimated Impact of Removing Uinta
PaR Stochastic Mean PVRR(d) (Benefit)/Cost ($ million) through 2036

Price-Policy Scenario	February 2018 (With Uinta)	High-Level Estimate (Without Uinta)	Marginal (Benefit)/Cost of Uinta
Low Gas, Zero CO_2	($150)	($146)	($4)
Low Gas, Medium CO_2	($179)	($172)	($7)
Low Gas, High CO_2	($337)	($312)	($25)
Medium Gas, Zero CO_2	($319)	($296)	($23)
Medium Gas, Medium CO_2	($357)	($330)	($27)
Medium Gas, High CO_2	($448)	($410)	($38)
High Gas, Zero CO_2	($568)	($517)	($51)
High Gas, Medium CO_2	($603)	($548)	($55)
High Gas, High CO_2	($694)	($629)	($66)

Q. What conclusions can you draw from the results provided in Table 24?

A. The high-level estimate based on results through 2036 shows that net benefits of the Combined Projects (without Uinta) are reduced by between $4 million and $66 million. In the medium natural gas, medium CO_2 price-policy scenario, net benefits are reduced by $27 million. Considering that results from the IRP models were used to select winning bids in the 2017R RFP, these findings confirm that it was reasonable to include Uinta in the 2017R RFP final shortlist. Importantly, these results also show that the Combined Projects will continue to deliver substantial net customer benefits with removal of the Uinta project. With Uinta removed, the net benefits from the Combined Projects range between $146 million and $629 million. In the medium natural gas, medium CO_2 price-policy scenario, the net benefits are estimated to be $330 million.

Q. What is the high-level estimate of the economic impact of removing Uinta based on nominal revenue requirement results through 2050?

A. Table 25 reports the high-level estimate of the economic impact of removing Uinta based on the nominal revenue requirement results through 2050. These PVRR(d) results are shown alongside the February 2018 economic analysis. Like Table 24 above, the difference between the original results that include Uinta and the high-level estimates without Uinta are an indicator of the marginal net benefit or cost of the Uinta project.

Table 25. Estimated Impact of Removing Uinta
Nominal PVRR(d) (Benefit)/Cost ($ million) through 2050

Price-Policy Scenario	February 2018 (With Uinta)	High-Level Estimate (Without Uinta)	Marginal (Benefit)/Cost of Uinta
Low Gas, Zero CO_2	$184	$146	$38
Low Gas, Medium CO_2	$127	$97	$31
Low Gas, High CO_2	($147)	($145)	($2)
Medium Gas, Zero CO_2	($92)	($97)	$5
Medium Gas, Medium CO_2	($167)	($162)	($4)
Medium Gas, High CO_2	($304)	($283)	($20)
High Gas, Zero CO_2	($448)	($411)	($37)
High Gas, Medium CO_2	($499)	($456)	($43)
High Gas, High CO_2	($635)	($576)	($59)

Q. What conclusions can you draw from Table 25?

A. The high-level estimate based on nominal revenue requirement results through 2050 shows that removal of Uinta reduces the net cost of the Combined Projects in three of the nine price-policy scenarios, and that the net benefits of the Combined Projects are reduced in six of the nine price-policy scenarios. In the medium natural gas, medium

CO_2 price-policy scenario, net benefits are reduced by $4 million. Importantly, when the impact of net benefits are based on nominal revenue requirement results through 2050, these results show that the Combined Projects will continue to deliver substantial net customer benefits with removal of the Uinta project. With Uinta removed, the net benefits from the Combined Projects in the scenarios where they occur range between $97 million and $576 million. In the medium natural gas, medium CO_2 price-policy scenario, the net benefits are estimated to be $162 million.

Q. What is the economic impact of removing Uinta based on updated results from the IRP model runs?

A. Table 26 reports the high-level estimate of the economic impact of removing Uinta alongside the updated modeled results using the 2036 and 2050 calculation methodologies. These results are presented for both the low natural gas, zero CO_2 and the medium natural gas, medium CO_2 price-policy scenarios. The table also shows the difference between the high-level estimate and the modeled results.

Table 26. Estimated Impact of Removing Uinta
Nominal PVRR(d) (Benefit)/Cost ($ million) through 2050

PaR Stochastic Mean PVRR(d) (Benefit)/Cost ($ million) through 2036			
Price-Policy Scenario	**High-Level Estimate (Without Uinta)**	**Modeled Result (Without Uinta)**	**Variance from Modeled Result**
Low Gas, Zero CO_2	($146)	($143)	($3)
Medium Gas, Medium CO_2	($330)	($338)	$8
Nominal PVRR(d) (Benefit)/Cost ($ million) through 2050			
Price-Policy Scenario	**High-Level Estimate (Without Uinta)**	**Modeled Result (Without Uinta)**	**Variance from Modeled Result**
Low Gas, Zero CO_2	$146	$154	($8)
Medium Gas, Medium CO_2	($162)	($174)	$12

Q. What conclusions can you draw from Table 26?

A. First, the modeled results are similar to the high-level estimates described above, and consequently, the high-level estimates provide a reasonable representation of the impact of removing Uinta.

Second, under the medium natural gas, medium CO_2 price-policy scenario, the Combined Projects still provide net customer benefits when Uinta is removed. When calculated from IRP model results through 2036, customer net benefits are $338 million (down by $19 million from $357 million in the February 2018 analysis). When calculated from the nominal revenue requirement results through 2050, customer net benefits are $174 million (up by $7 million from the $167 million in the February 2018 analysis).

Third, under the low natural gas, zero CO_2 price-policy scenario, the Combined Projects still provide net customer benefits with Uinta removed when the PVRR(d) is calculated from IRP model results through 2036. Based on this methodology, customer net benefits are $143 million (down by $7 million from the $150 million benefit in the February 2018 analysis). When calculated from the nominal revenue requirement results through 2050, net costs are $154 million (down by $30 million from the $184 million in the February 2018 economic analysis).

Q. Have you calculated the change in capital costs that would have to occur to eliminate net benefits in the medium natural gas, medium CO_2 price-policy scenario?

A. Yes. Removal of the Uinta project reduces capital costs for the Combined Projects to $[redacted] billion. In-service capital costs would have to increase by approximately

11.1 percent (or $[redacted] million) to eliminate net benefits in the medium natural gas, medium CO_2 price-policy scenario.

Q. Do the Combined Projects without Uinta still provide overall customer net benefits?

A. Yes. As set forth above, when using the IRP modeling, the Combined Projects still provide robust customer net benefits under all nine price-policy scenarios. Although the benefits have decreased slightly, they remain substantial. In addition, under the nominal revenue requirement view, the net benefits remained fairly consistent, increasing in some price-policy scenarios and decreasing in others. Although neither view is dispositive, each of these views provides important insight into how the Combined Projects are expected to impact the Company's revenue requirement. Taken together, each of these views indicate that the removal of Uinta does not adversely impact the customer benefits, and the acquisition of the Combined Projects remains in the public interest.

III. PRYOR MOUNTAIN WIND PROJECT

Q. Did you conduct the economic analysis supporting acquisition of the Pryor Mountain Wind Project?

A. Yes. I prepared the economic analysis for the 240 MW Pryor Mountain Wind Project, which supports PacifiCorp's decision to move forward with the project. I completed this analysis in September 2019.

Q. Please provide background on the Pryor Mountain Wind Project.

A. In May 2019, PacifiCorp executed an agreement for the development rights associated with the Pryor Mountain Wind Project, located in Montana. In June 2019, PacifiCorp and Vitesse, LLC (Vitesse) (a wholly-owned subsidiary of Facebook, Inc.) executed an agreement for the purchase of all RECs generated by Pryor Mountain over a 25-year period under PacifiCorp's Oregon Schedule 272 – Renewable Energy Rider Optional Bulk Purchase Option. In September 2019, PacifiCorp executed the Engineering, Procurement, and Construction Contractor (EPC) and wind turbine supplier agreements for the project. Mr. Chad A. Teply provides additional information about this project in his testimony.

Q. Was the Pryor Mountain Wind Project the result of an RFP issued by PacifiCorp?

A. No. PacifiCorp pursued the Pryor Mountain Wind Project outside of an RFP because it was a unique, time sensitive opportunity to provide significant value to customers. The opportunity evolved over a very compressed timeline, beginning in October 2018, with final terms on all material agreements completed before September 30, 2019. Under Oregon Commission rules, PacifiCorp filed a notice of an exception to the RFP guidelines on this basis on September 27, 2019.

Q. Is the Pryor Mountain Wind Project eligible for the full PTC?

A. Yes. As Mr. Teply describes, the project will be in service by December 31, 2020, and it meets all other PTC requirements.

Q. Did you consider the Schedule 272 agreement for REC sales in your economic analysis?

A. Yes. The Schedule 272 Agreement represents a unique opportunity to leverage Vitesse's desire to purchase RECs from a specified resource while providing a cost-effective energy resource to serve PacifiCorp's customers. The Company estimates that the present-value cost reduction resulting from Vitesse's purchase of all RECs generated by the project is $[redacted], which will mitigate risks under the various price-policy assumptions.

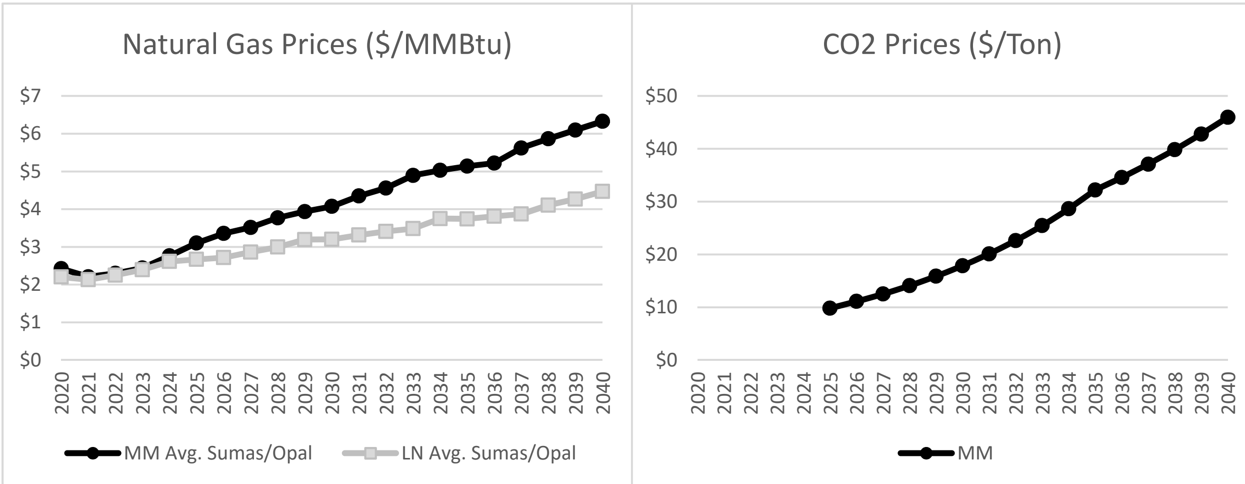
Q. Please describe your economic analysis of the Pryor Mountain Wind Project.

A. The methodology I used to perform the economic analysis of the Pryor Mountain Wind Project is the same I used to perform the economic analysis of the other resources addressed in my testimony. I relied on PaR runs with a simulation period covering the 2019-2038 time frame. System benefits from the development of the Pryor Mountain Wind Project, which includes sale of the associated RECs in accordance with the Schedule 272 Agreement, are based on two PaR simulations—one with incremental generation from the project and one without incremental generation from the project.

Q. What price-policy scenarios did you use in your economic analysis?

A. I used the same two price-policy scenarios as in PacifiCorp's project-by-project wind repowering analysis and for Foote Creek I—one assuming medium natural gas price and medium CO_2 price assumptions (the "MM" price-policy scenario) and one assuming low natural gas price and no CO_2 price assumptions (the "LN" price-policy scenario). These assumptions are summarized in Figure 10.

Figure 10. Price-Policy Assumptions in the Economic Analysis of the Pryor Mountain Wind Project



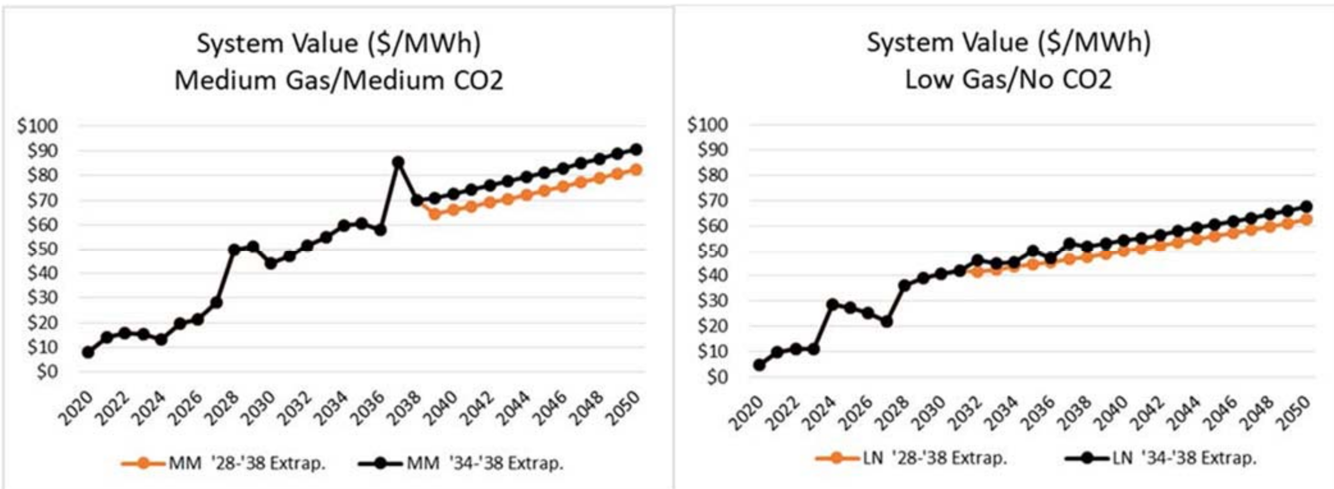
Q. Over what period did you analyze the costs and benefits of the Pryor Mountain Wind Project?

A. My analysis covers the 30-year life of the asset—from 2020 through 2050.

Q. Please explain how you developed a forecast of the project's benefits beyond the 2038 time frame?

A. As with the wind repowering projects and Combined Projects, the system value of incremental energy is converted to a dollar-per-megawatt-hour value by dividing the reduction in annual system costs associated with the Pryor Mountain Wind Project by the change in incremental energy from the Pryor Mountain Wind Project. This analysis was performed for the MM and LN price-policy scenarios through 2038. The value of energy is extended out through 2050 by extrapolating the system values calculated from modeled data over two different time frames—2028–2038, and 2034–2038. The assumed system value, expressed in dollars-per-megawatt-hour, is applied to the incremental energy output from Pryor Mountain Wind Project. The system value of the Pryor Mountain Wind Project is summarized for both price-policy scenarios in Figure 11.

Figure 11. System Value Used in the Economic Analysis of Pryor Mountain Wind Project



Q. Please provide the results of your economic analysis.

A. The Pryor Mountain Wind Project is expected to provide significant net benefits for customers. Table 27 summarizes the PVRR(d) benefits calculated from changes in system costs through 2050. This table also presents the same information on a levelized dollar-per-megawatt-hour basis. Under the MM price-policy scenario, net benefits range between $69 million and $82 million. Under the LN price-policy scenario, the PVRR(d) ranges between a $7 million benefit and a $1 million cost, depending upon the period used to extrapolate benefits beyond 2038. The execution of the Schedule 272 agreement with Vitesse was a necessary milestone to ensure the Pryor Mountain Wind Project could move forward and mitigates the risk of deteriorating value under a variety of price and policy scenarios, including the most conservative LN price policy scenario. Additionally, while not explicitly analyzed, customer benefits would increase significantly with high natural-gas price and/or high CO_2 price assumptions.

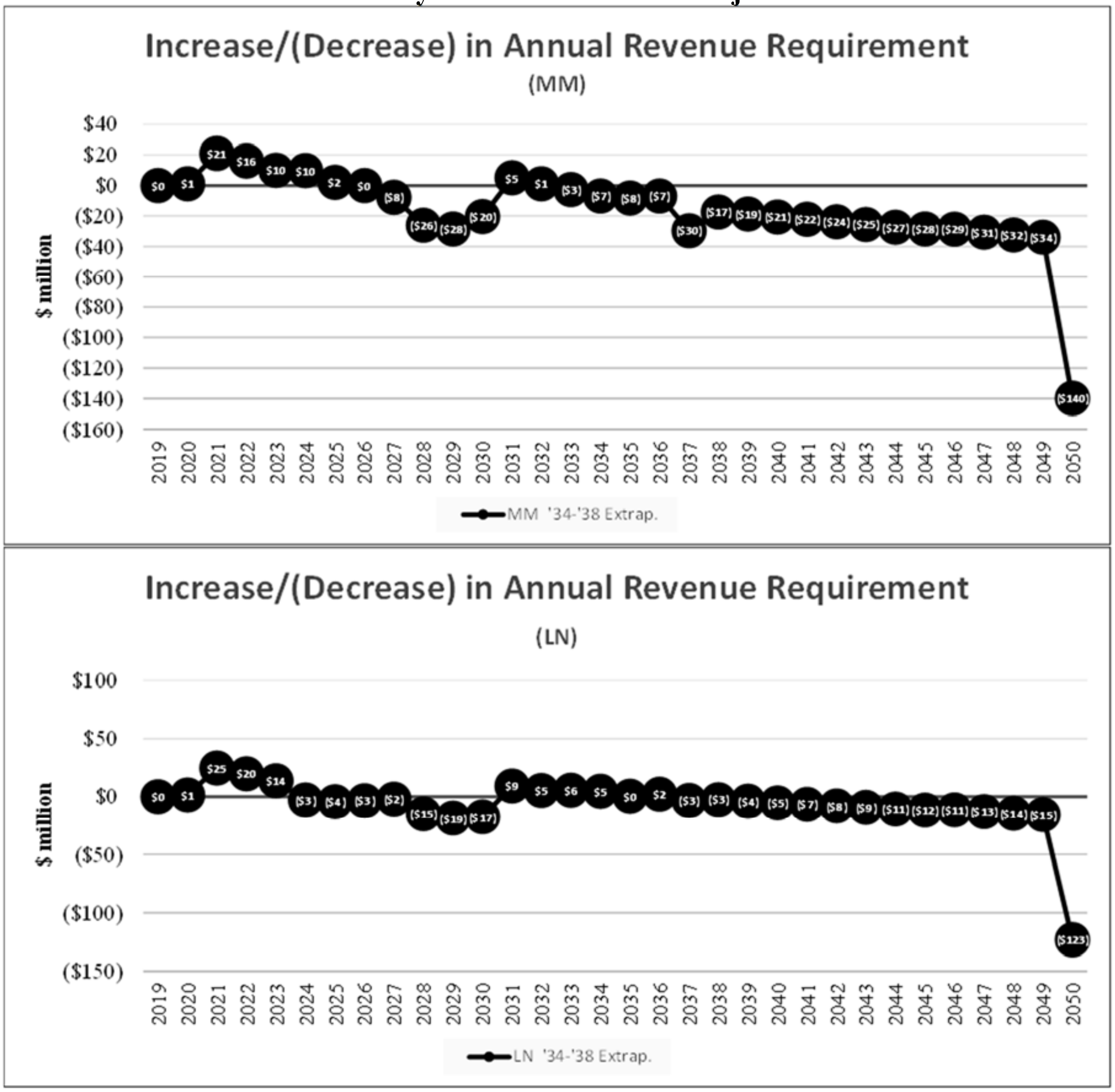
Table 27. Net Benefits from the Pryor Mountain Wind Project

Price-Policy Scenario (Extrapolation Method)	PVRR(d) Net (Benefit)/Cost ($ million)	Nom. Lev. Benefit ($/MWh of Incremental Energy)
MM ('28-'38 Extrapolation)	($69)	($7.22)
MM ('34-'38 Extrapolation)	($82)	($8.56)
LN ('28-'38 Extrapolation)	$1	$0.12
LN ('34-'38 Extrapolation)	($7)	($0.72)

Q. Have you analyzed the change in annual revenue requirement associated with the Pryor Mountain Wind Project?

A. Yes. Figure 12 shows the estimated change in nominal annual revenue requirement due to the Pryor Mountain Wind Project for the MM and LN price-policy scenarios with extrapolated benefits derived from modeled results over the period 2034–2038. This figure reflects the change in nominal revenue requirement associated with Pryor Mountain Wind Project netted against system benefits, which were calculated as described above. Considering both the MM and LN cases illustrated below, the Pryor Mountain Wind Project reduces nominal revenue requirement during a majority of its depreciable life.

Figure 12. (Reduction)/Increase in Total-System Annual Revenue Requirement from the Pryor Mountain Wind Project



IV. SALES AND LOAD FORECAST

Q. Please summarize the changes in Washington sales in the current filing as compared to the Washington sales included in the Company's 2014 general rate case, docket UE-140762 (2014 Rate Case).

A. As shown in Table 28 below, PacifiCorp's Washington sales in the test period are 20,972 MWh, or 0.5 percent higher than the sales included in the 2014 Rate Case. The increase in sales is driven by increased sales to the commercial and irrigation classes and is offset in part by a decrease in sales to the residential, industrial and lighting classes.

Table 28. Washington Sales Comparison* (MWh)

	2020 Rate Case 12 ME Jun-19	2014 Rate Case 12 ME Dec-13	Difference	Percentage Change
Residential	1,547,792	1,580,882	(33,090)	-2.1%
Commercial	1,559,609	1,481,385	78,225	5.3%
Industrial	749,767	790,071	(40,304)	-5.1%
Irrigation	164,796	148,533	16,262	10.9%
Lighting	9,169	9,290	(121)	-1.3%
Total	4,031,134	4,010,161	20,972	0.5%
* At meter				

Q. How are the temperature normalized sales and load for the test period used in the preparation of this case?

A. The temperature normalized retail sales for the test period are used by Mr. Robert M. Meredith to develop present revenues and proposed rates, and Ms. Shelley E. McCoy uses the test period temperature normalized loads to calculate inter-jurisdictional allocation factors.

Q. Please summarize the changes in forecasted load compared to the 2014 Rate Case.

A. As shown in Table 29, the forecasted load for NPC in this case (the rate effective period of 12 months ending December 2021) are higher than forecasted loads for the 2014 rate case (12 months ending March 2016) for both the state of Washington and the system as a whole.

Table 29. Comparison of System Loads* in NPC.

State	2020 Rate Case 12 months ending Dec-21 (MWh)	2014 Rate Case 12 months ending Mar-16 (MWh)	Difference	Percentage Difference
Washington	4,558,260	4,421,740	136,520	3.1%
Oregon	15,219,850	14,714,670	505,180	3.4%
California	881,850	883,290	-1,440	-0.2%
Utah	26,586,297	25,588,543	997,754	3.9%
Idaho	3,976,120	3,720,890	255,230	6.9%
Wyoming	9,689,150	10,558,050	-868,900	-8.2%
System Load	60,911,527	59,887,183	1,024,344	1.7%

*At system input (includes losses)

The increase in the load forecast for Washington is driven by an increase in the commercial class offset in part by a decrease in forecasted sales to the residential class.

Q. How are the forecasted loads for the PacifiCorp system used in preparing this case?

A. The forecasted loads for PacifiCorp's system are used by Mr. Michael G. Wilding to calculate NPC.

Q. Please list the assumptions and updates to the current load forecast.

A. The Company updated the following information in the current load forecast:

- Actual sales January 2000 through January 2019.
- Updated weather splines to use load research data over the October 2013 through September 2018 timeframe.
- The Company's load forecast is based on normal weather defined by the 20-year time period of 1999–2018.
- Economic data is based on the October 2018 release from IHS Markit, which includes households, population, and employment figures.

Q. Are there any changes in the load forecast methodology since the 2014 Rate Case?

A. Yes. PacifiCorp updated its residential customer forecasting methodology by adopting a differenced model approach. Rather than directly forecasting the number of customers as was conducted for the 2014 Rate Case, the differenced model predicts the monthly change in number of customers. PacifiCorp performed a historical comparison of the forecasted results using both methods against actual customer counts and determined the differenced model produced a more accurate customer forecast.

CONCLUSION

Q. Based on your testimony, what do you recommend to the Commission?

A. I recommend that the Commission conclude that PacifiCorp's repowered wind facilities, EV 2020 Wind Projects and Transmission Projects, and Pryor Mountain Wind Project are prudent and in the public interest.

Q. Does this conclude your direct testimony?

A. Yes.