REDACTED
Docket No. UE 352
Exhibit PAC/300
Witness: Rick T. Link

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Direct Testimony of Rick T. Link

December 2018

DIRECT TESTIMONY OF RICK T. LINK
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ATTACHED EXHIBITS

Q. Please state your name, business address, and present 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.

QUALIFICATIONS

Q. Please describe your current responsibilities.

A. I am responsible for PacifiCorp's integrated resource plan (IRP), implementing resource request-for-proposals (RFP), structured commercial business and valuation activities, long-term commodity price forecasts, and long-term load forecasts. Most relevant to this proceeding, I am responsible for the economic analysis used to screen significant resource investments.

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. From 2003 through 2016, I have held several analytical and leadership positions responsible for developing long-term commodity price forecasts, pricing structured commercial contract opportunities, and developing financial models to evaluate resource investment opportunities, negotiating commercial contract terms, and overseeing development of PacifiCorp's resource plans. I was responsible for delivering PacifiCorp's 2013, 2015, and 2017 IRPs, have been directly involved with implementing several resource RFPs, 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 Public Utility Commission of Oregon (Commission), and the public utility commissions in Washington, California, Idaho, Utah, and Wyoming.

PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

A. I present and explain the economic analysis that shows PacifiCorp's decision to upgrade, or "repower", certain wind resources is prudent and provides significant customer benefits. I also summarize PacifiCorp's assessment of wind repowering opportunities in the 2017 IRP.

Q. Please summarize your testimony.

A. PacifiCorp's economic analysis supports repowering approximately 999.1 megawatts (MW) of existing wind resource capacity for twelve wind facilities—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—in 2019 and 2020. Nine of these facilities are included in this filing. The three facilities excluded from this filing are two planned for construction in 2020 (Glenrock III and Dunlap) and Rolling Hills, which is not in Oregon rates.

The repowered wind facilities will qualify for an additional 10 years of federal production tax credits (PTCs), produce more energy, reset the thirty-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, 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 certificates (RECs), understate the potential benefits from reduced carbon-dioxide 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 least-cost, least-risk 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. As discussed later in my testimony, PacifiCorp has since expanded the wind repowering scope to include its Goodnoe Hills wind facility. With the addition of Goodnoe Hills, PacifiCorp is proceeding with its plans to repower approximately 999.1 MW of existing wind capacity.

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

A. As explained in Mr. Timothy J. Hemstreet's testimony (Exhibit PAC/200), PacifiCorp purchased safe-harbor equipment from General Electric International, Inc., and Vestas American Wind Technology, Inc. in December 2016. Consistent with Internal Revenue Service (IRS) guidance, these equipment purchases, totaling

$77.8 million, secured an option for PacifiCorp to repower its fleet of owned wind resources, thereby qualifying them for the full value of federal PTCs.

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

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

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

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

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

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

A. PacifiCorp assumed repowering 905 MW of existing wind resource capacity in the 2017 IRP. Of the 905 MW, approximately 594 MW of this capacity are located in Wyoming (Glenrock, Rolling Hills, Seven Mile Hill, High 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, which is located in Washington.

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

A. The 2017 IRP wind repowering sensitivity showed significant customer benefits across a range of assumptions related to forward market prices and possible federal carbon-dioxide (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 (EPC) notice to proceed to begin implementing wind repowering for specific projects consistent with updated financial analysis.
> - By December 31, 2020, complete installation of wind repowering equipment on all identified projects.[1]

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

A. PacifiCorp refined and updated its economic analysis of plant-specific wind

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

repowering opportunities, and is now including Goodnoe Hills in the wind repowering project. Since the 2017 IRP, the economic analysis has been updated to reflect more current assumptions, including changes in the federal tax rate for corporations. The rest of my testimony presents and explains this economic analysis. Mr. Hemstreet explains that PacifiCorp continues to evaluate repowering of the Foote Creek facility in Wyoming, but due to differences in project scope for this older-vintage facility, Foote Creek is not included in the economic analysis of the wind repowering project at this time. Mr. Hemstreet also discusses the status of the construction agreements and addresses the construction schedule.

Q. Did the Commission acknowledge the 2017 IRP?

A. Yes. The Commission acknowledged the 2017 IRP in Order No. 18-138, issued on April 27, 2018.[2] The Commission conditioned its acknowledgement of Energy Vision 2020 projects, which includes the wind repowering project, by reserving the right to conduct a full reasonableness review in the future and limit risks to customers, and requiring an updated economic analysis in the 2017 IRP Update.

Q. Did PacifiCorp update its wind repowering analysis in its 2017 IRP Update, filed on May 1, 2018?

A. Yes. PacifiCorp filed its 2017 IRP Update on May 1, 2018. The IRP Update includes a summary of the February 2018 analysis I discuss below.

[2] *In the Matter of PacifiCorp, dba Pacific Power, 2017 Integrated Resource Plan*, Docket LC 67, Order No. 18-138, 7-9 (April 27, 2018).

MODELING SCOPE, METHODOLOGIES, AND ASSUMPTIONS

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

A. The economic analyses described in my testimony cover the entire repowering project, which consists of twelve wind facilities, in order to estimate customer benefits from repowering approximately 999.1 MW of existing wind resource capacity located in Wyoming, Oregon, and Washington in 2019 and 2020. These economic analyses informed PacifiCorp's decision to move forward with the project. As noted above, nine of these facilities are included in this filing, and three are excluded (Glenrock III, Dunlap, and Rolling Hills).

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 operations and maintenance (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. The models were used to support the successful acquisition of the Chehalis combined-cycle plant, to support selection of the Lake Side 2 combined-cycle resource through a RFP process, and the SO model has been used to evaluate installation of emissions control systems. These models were also be used to evaluate bids in PacifiCorp's recent 2017R RFP, issued to solicit bids for new wind resources, and in PacifiCorp's recent 2017S RFP, issued to solicit bids for new solar resources.

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

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

Q. How did PacifiCorp use PaR to assess stochastic system cost risk associated with wind repowering?

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

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

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

A. The effective combined federal and state income tax rate affects PacifiCorp's post-tax weighted average cost of capital, which is used as the discount rate in the SO model and PaR. 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. The current value of federal PTCs is $24/MWh, which equates to a $31.82/MWh reduction in revenue requirement assuming an effective combined federal and state income tax rate of 24.587 percent. The impact of the income tax rate assumptions were applied to all PTC-eligible resource alternatives available in the SO model.

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

A. Yes. In addition to assessing stochastic system cost risk, PacifiCorp analyzed the wind-repowering project under a range of assumptions regarding wholesale market prices and CO_2 policy 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). The cost-and-performance assumptions for the wind facilities studied in this updated economic analysis are summarized in Confidential Exhibit PAC/301. 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 off of estimated annual revenue requirement extended out through 2050 captures the significant increase in projected wind energy output beyond the 20-year forecast period.

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

A. The change in wind energy output between cases with and without repowering experiences a step change in the 2036-through-2040 time frame, when the wind facilities, originally placed in-service during the 2006-through-2010 time frame, would otherwise have hit the end of their depreciable life. Before the 2036-through-2040 time frame, the change in wind energy output reflects the incremental energy production that results from installing modern equipment on repowered wind assets. Beyond the 2036-through-2040 time frame, the change in wind energy output between a case with and without repowering reflects the full energy output from the repowered wind facilities that would otherwise be retired.

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.[3] 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).

[3] For preapproval proceedings in other states, PacifiCorp performed an earlier project-wide study in early 2017. That study predated tax code reforms and was therefore supplanted by the February 2018 analysis, so I do not describe it further in this testimony.

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.

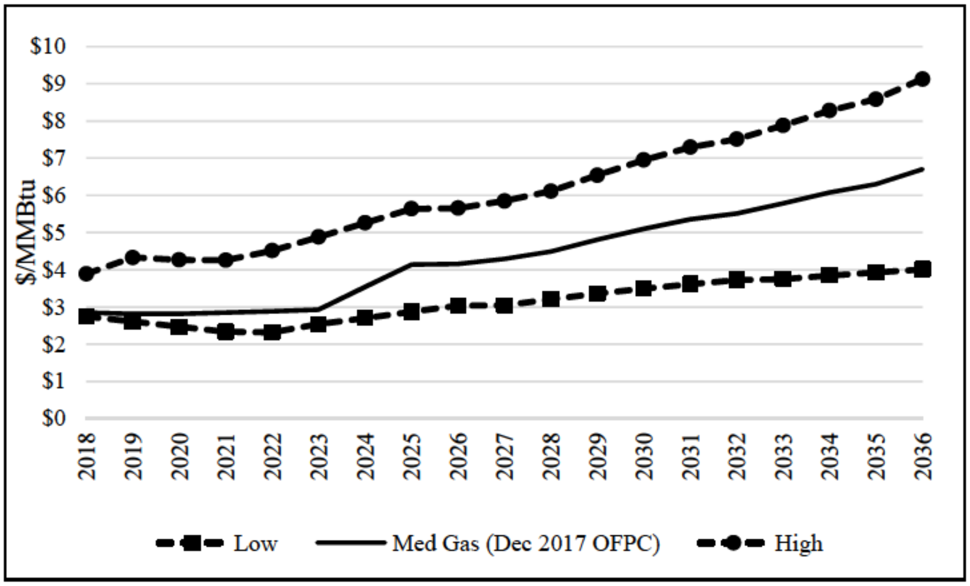
A. The medium-natural-gas price assumptions that are paired with zero CO_2 prices reflect natural-gas prices from PacifiCorp's official forward price curve (OFPC) dated December 29, 2017. This OFPC uses observed forward market prices as of December 29, 2017, for 72 months, followed by a 12-month transition to natural-gas prices based on a forecast developed by [redacted]. The medium-, low-, and high-natural-gas price assumptions used for all other scenarios were chosen after reviewing a range of credible third-party forecasts developed by [redacted], and the U.S. Department of Energy's Energy Information Administration. Confidential Exhibit

PAC/302 shows the range in natural-gas price assumptions from these third-party forecasts relative to those adopted for the price-policy scenarios to evaluate the wind repowering project.

The low-natural-gas price assumption was derived from a low-price scenario developed by [redacted]. The medium-natural-gas price assumption, which is used beyond month 84 in the December 2017 OFPC, and in all months when medium-natural-gas prices are paired with medium or low CO_2 price assumptions, is based on a base-case forecast from [redacted] that is reasonably aligned with other base-case forecasts. The high-natural-gas price assumption was based on a high-price scenario from [redacted] that is characterized by exaggerated boom-bust cycles (cyclical periods of high prices and low prices). PacifiCorp smoothed the boom-bust cycle in this third party’s high-price scenario because the specific timing of these cycles are extremely difficult to project with reasonable accuracy.

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

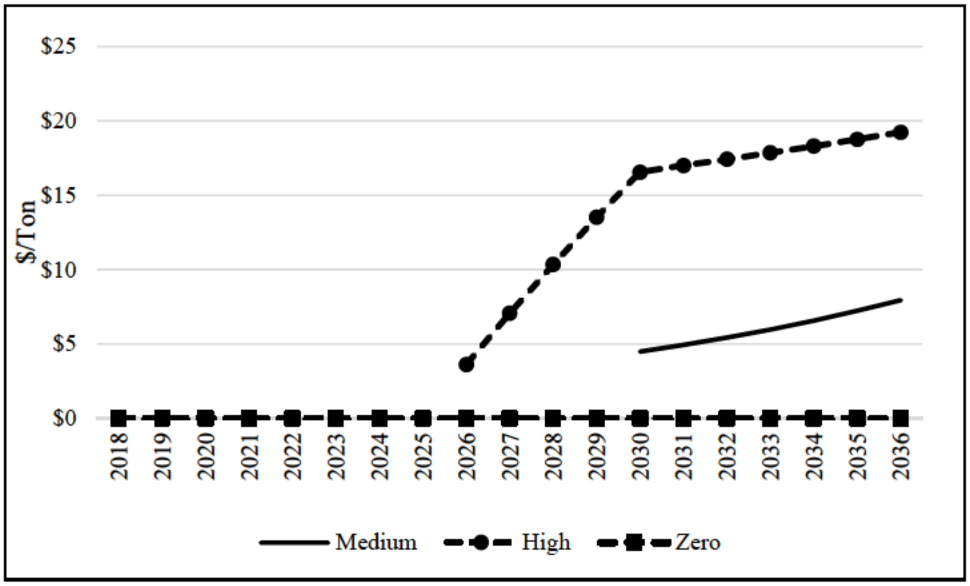
Figure 1. Nominal Natural-Gas Price Scenarios in the February 2018 Analysis



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?

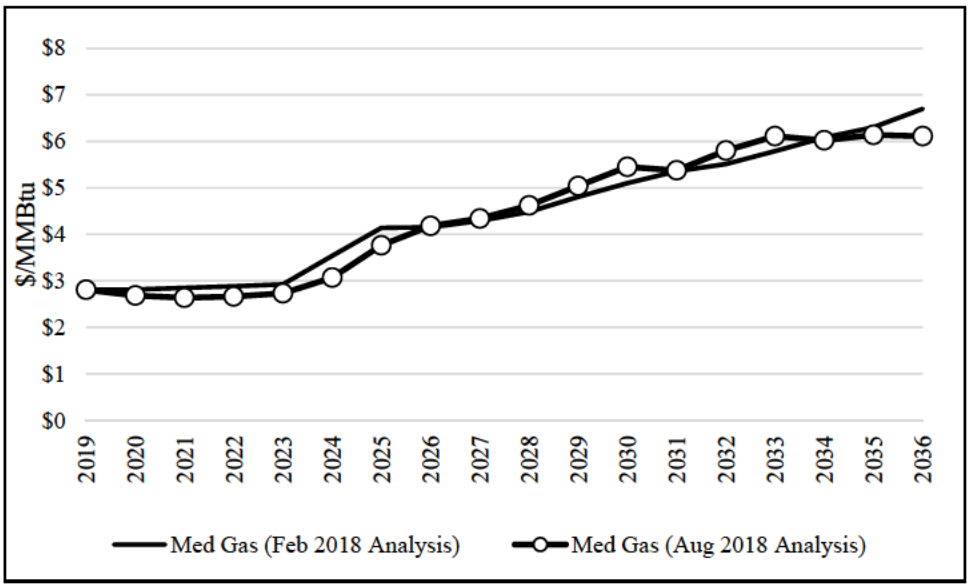
A. In August 2018, PacifiCorp conducted a more targeted wind repowering analysis to understand how the results were impacted by certain assumption updates, which I describe later in my testimony. For this study, therefore, PacifiCorp only updated its medium natural-gas price and CO_2 price assumptions.

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 February 2018 wind repowering analysis. The nominal levelized price over the period 2019 through 2036 from the August 2018 analysis is \$3.97/MMBu, which is down just two percent relative to the \$4.05/MMBtu levelized price from the February 2018 analysis.

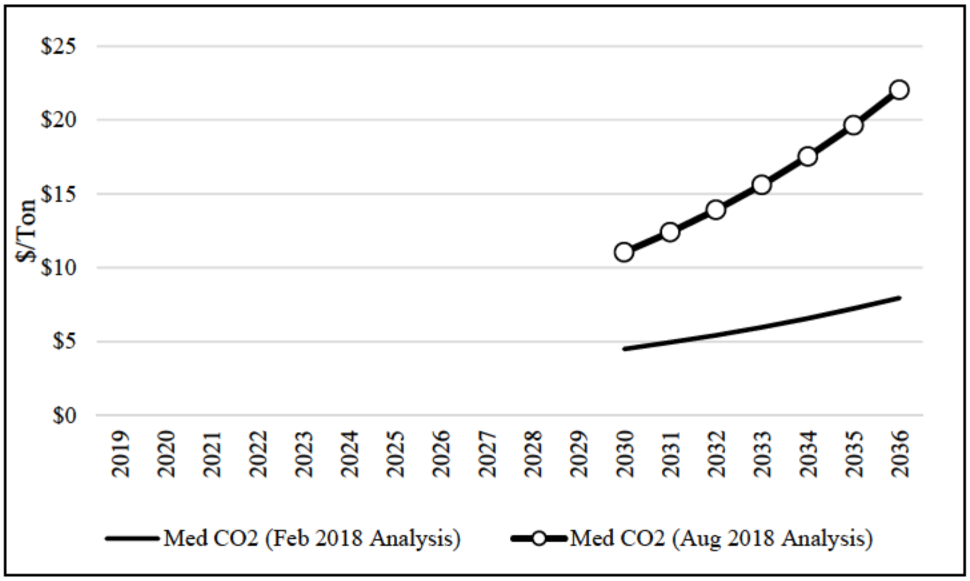
Figure 3. Nominal Natural-Gas Price Assumptions in the August 2018 Analysis Relative to Medium Price Assumptions from the February 2018 Analysis



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 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 (Pre-Approval Proceedings)	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, the company determined which individual projects are expected to provide net customer benefits, and then these projects were analyzed under all price-policy scenarios.

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

A. Table 2 summarizes the PVRR(d) results for each wind facility. 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 taking into account the size of each wind facility?

A. Yes. The magnitude of the PVRR(d) results must be considered in relation to the specific attributes of the repowered wind facility, including the size of the facility, the expected cost to repower the facility, and the level of annual energy output expected after the new equipment is installed. For example, the PVRR(d) for McFadden Ridge shows a $7 million benefit when repowered (using medium natural-gas and medium CO_2 price-policy assumptions)—the lowest PVRR(d) among all of the project-by-project results. The PVRR(d) benefit for McFadden Ridge is approximately 14 percent of the $50 million benefit for Marengo I, which yields the highest PVRR(d) among all of the project-by-project results. However, the 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 early 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, 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 PVRR(d) results shown in Table 6 are provided as Exhibit PAC/303.

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. 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 PAC/304.

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?

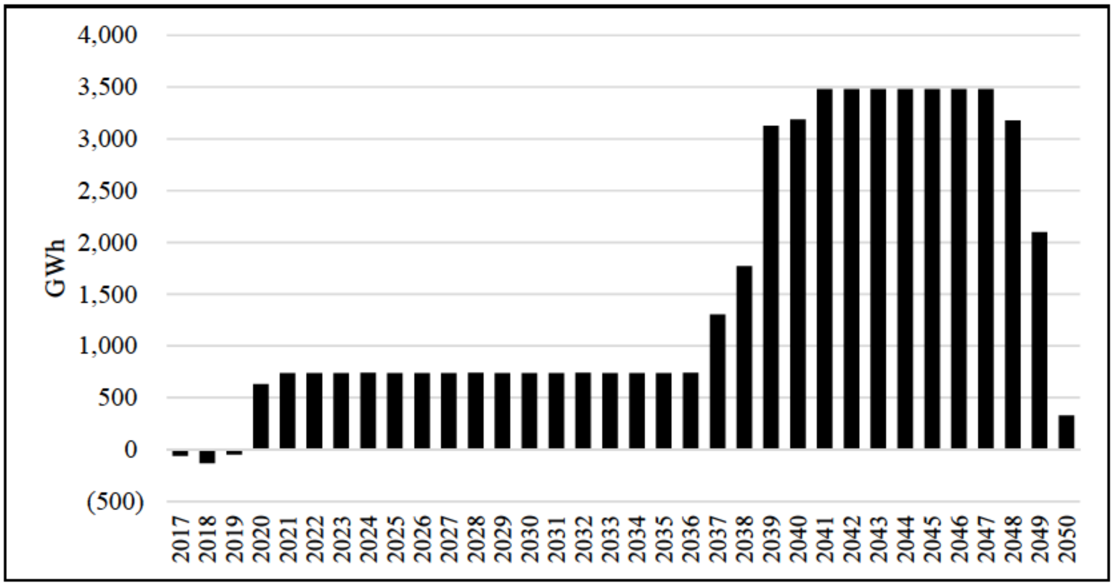
A. Present-value gross customer benefits calculated over the remaining life of the repowered wind facilities range between $1.14 billion and $1.48 billion, which compares to present-value project costs totaling $1.01 billion.

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 of the wind resources within the project scope are repowered, the average annual incremental increase in wind energy output is approximately 738 GWh. Beyond 2040, and before the new equipment hits the end of its depreciable life, the average annual incremental increase in wind-energy output is approximately 3,478 GWh.

Figure 5. Change in Incremental Wind Energy Output Due to Wind Repowering (GWh), February 2018



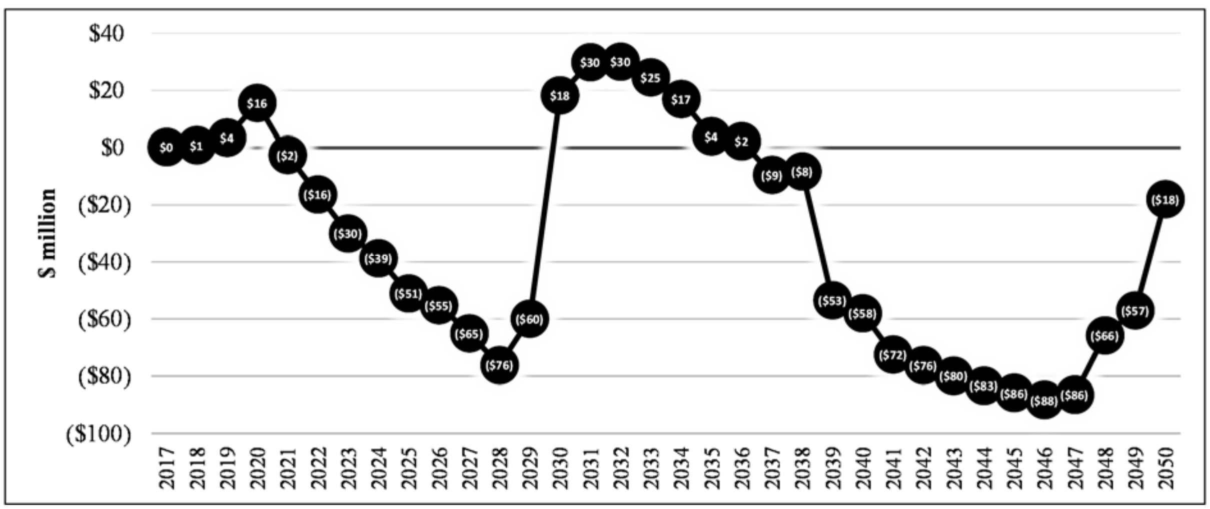
Q. Is there additional potential upside to the PVRR(d) results calculated from the change in estimated annual revenue requirement through 2050?

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, 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 of the facilities were assumed to be repowered in 2019, except the Dunlap facility, which was assumed to be repowered toward the end of 2020.[4] 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

[4] Based on more current information, both the Dunlap and Glenrock III facilities will be repowered in 2020. As noted elsewhere in my testimony, these facilities are therefore not included in this Schedule 202 filing for 2019.

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 Modeling	$59.08	($273)
70% of PV	$49.49	($213)
100% of PV	$70.70	($351)
130% of PV	$91.92	($489)

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

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 included in the company's 2017 IRP.[5] 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

[5] 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.

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 Mean	($466)	($180)	($286)
PaR Risk Adjusted	($489)	($189)	($300)
Low Gas, Zero CO_2			
SO Model	($301)	($159)	($142)
PaR Stochastic Mean	($300)	($141)	($159)
PaR Risk Adjusted	($315)	($148)	($167)

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

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.[6] 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

[6] 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.

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 and PaR models through 2036 are similar to, and generally improve upon, projected customer benefits relative to the February 2018 project-by-project PVRR(d) results.[7] Table 11 displays the two sets of analyses side by side. These results confirm that with updated

[7] 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.

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 1	($33)	($40)	($28)	($31)	($29)	($39)
Seven Mile Hill 2	($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 (2017$)	August 2018 (2018$)	February 2018 (2017$)	August 2018 (2018$)	February 2018 (2017$)	August 2018 (2018$)
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 taking into account 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 prior 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; Feb. and Aug. 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.

CONCLUSION

Q. Please summarize the conclusions of your testimony.

A. PacifiCorp's analysis supports repowering approximately 999.1 MW of existing wind resource capacity located in Wyoming, Oregon, and Washington, which includes the nine facilities included in this 2019 Schedule 202 filing. The repowered wind facilities will qualify for an additional 10 years of federal PTCs, produce more energy, reset the 30-year depreciable life of the assets, and reduce run-rate operating costs. The economic analysis of the wind repowering project demonstrates that net benefits, which include federal PTC benefits, NPC benefits, other system variable-cost benefits, and system fixed-cost benefits, more than outweigh net project-wide costs.

Q. What do you recommend?

A. As supported by the economic analyses described in my testimony, I recommend the Commission determine that the decision to repower certain wind facilities in 2019 is prudent and approve this Schedule 202 filing requesting the proposed ratemaking treatment for the new costs of the wind repowering project.

Q. Does this conclude your direct testimony?

A. Yes.