BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE	)	
APPLICATION OF ROCKY	)	**CASE NO. PAC-E-21-07**
MOUNTAIN POWER FOR	)	
AUTHORITY TO INCREASE ITS	)	**Direct Testimony of Rick T.Link**
RATES AND CHARGES IN IDAHO	)	**REDACTED**
AND APPROVAL OF PROPOSED	)	
ELECTRIC SERVICE SCHEDULES	)	
AND REGULATIONS	)	

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-21-07

May 2021

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I. INTRODUCTION AND QUALIFICATIONS

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 d/b/a Rocky Mountain Power ("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 load 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 Idaho Public Utilities Commission ("Commission"), the Utah Public Service Commission, the Wyoming Public Service Commission, the Public Utility Commission of Oregon, the Washington Utilities and Transportation Commission, and the California Public Utilities Commission.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

A. I provide the economic analyses that support the resource decisions for several plant investments included in the case for recovery in base rates. First, I demonstrate that the Company's decision to repower the Foote Creek I wind facility will provide benefits to customers. Second, I explain that the Energy Vision 2020 ("EV 2020") project, which includes new wind and transmission, helps meet the Company's need for new resources. Further, I show that EV 2020 will deliver significant customer net benefits despite a slight increase in capital costs relative to those assumed when the Company decided to move forward with the project. Third, PacifiCorp has acquired another wind resource, the Pryor Mountain Wind Project in Montana, which achieved commercial operation in April 2021. I present and explain the economic analysis that demonstrates that this investment is reasonable and prudent. Fourth, I present economic analysis supporting the conversion of Naughton Unit 3 to natural gas in 2020.

Q. How have you organized your testimony?

A. I have divided my testimony into seven sections, including the introduction in Section I and this Section II. Section III of my testimony addresses repowering the Foote Creek I wind facility. I address EV 2020 in Section IV of my testimony. Section V of my testimony addresses PacifiCorp's new Pryor Mountain Wind Project. Section VI presents PacifiCorp's resource decisions involving Naughton Unit 3. Finally, my conclusion is provided in Section VII.

III. REPOWERING OF FOOTE CREEK I

Q. Please describe the scope of PacifiCorp's full repowering project.

A. The full wind repowering project includes 13 wind facilities, representing approximately 1,040 megawatts ("MW") of installed wind capacity. In Case No. PAC-E-17-06 ("Repowering Proceeding"), the Company presented the economic analysis and received approval for 12 of the 13 wind facilities, totaling approximately 999.1 MW. The facilities approved in the Repowering Proceeding were Glenrock I, Glenrock III, Rolling Hills, Seven Mile Hill I, Seven Mile Hill II, High Plains, McFadden Ridge, and Dunlap in Wyoming; the Marengo I, Marengo II and Goodnoe Hills in Washington; and the Leaning Juniper facility in Oregon.[1] This filing includes the 13^{th} facility, Foote Creek I in Wyoming, which presents similar economic benefits,

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[1] *In the Matter of the Application of Rocky Mountain Power for Binding Rate Making Treatment for Wind Repowering*, Case No. PAC-E-17-06 Order No. 33954 (Dec. 28, 2017). The wind facilities approved for repowering from this case are Glenrock I, Glenrock III, Rolling Hills, Seven Mile Hill I, Seven Mile Hill II, High Plains, McFadden Ridge, Dunlap I, Marengo I, Marengo II, Goodnoe Hills and Leaning Juniper. The Company is demonstrating that the benefits to repower the Foote Creek I facility are prudent and in the public interest within this rate case.

as described further below.

Q. Is PacifiCorp seeking recovery in base rates for all 13 facilities in the repowering project in this general rate case?

A. Yes. All the facilities will be in service by the rate effective date for this proceeding so the Company is seeking to include the costs in base rates for all 13 of the repowering facilities.

Q. Generally, what are the benefits of the repowering project?

A. Repowering upgrades increase output of the wind facilities by 27 percent, extend the operating lives of the facilities, and allow the facilities to requalify for federal production tax credits ("PTCs") for 10 additional years.

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

A. As discussed in Mr. Timothy J. Hemstreet's testimony, 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. This is different from repowering the rest of PacifiCorp's wind fleet, where the existing towers, foundations, and energy collection systems remained in place and were able to accommodate more modern wind-turbine-generator equipment.

Repowering at the Foote Creek I facility involved 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 was Foote Creek I not included in the Repowering Proceeding and your February 2018 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?

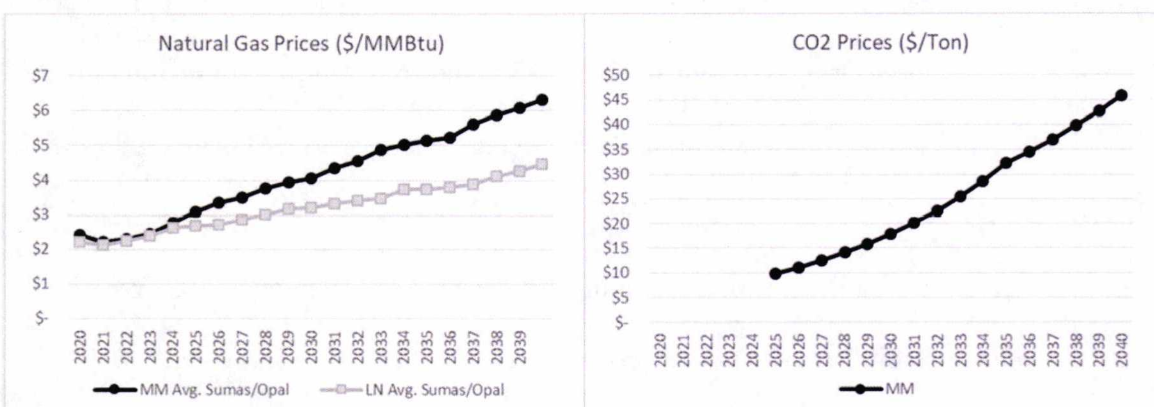
A. PacifiCorp made the decision to repower Foote Creek I in June 2019.

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

A. PacifiCorp originally decided to repower 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 and $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 1.

Figure 1. 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 and $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 in Case No. PAC-E-17-06. The system value of incremental wind energy in eastern Wyoming is calculated from two planning and risk ("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 timeframe. 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 1 summarizes the present-value revenue requirement differential ("PVRR(d)") between cases, with and without Foote Creek I repowering. A negative value indicates the project is expected to benefit customers. 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/megawatt-hour ("MWh") and $3/MWh, respectively. These results are consistent with the range of the net benefits associated with other wind repowering facilities presented in my direct testimony in the Repowering Proceeding.

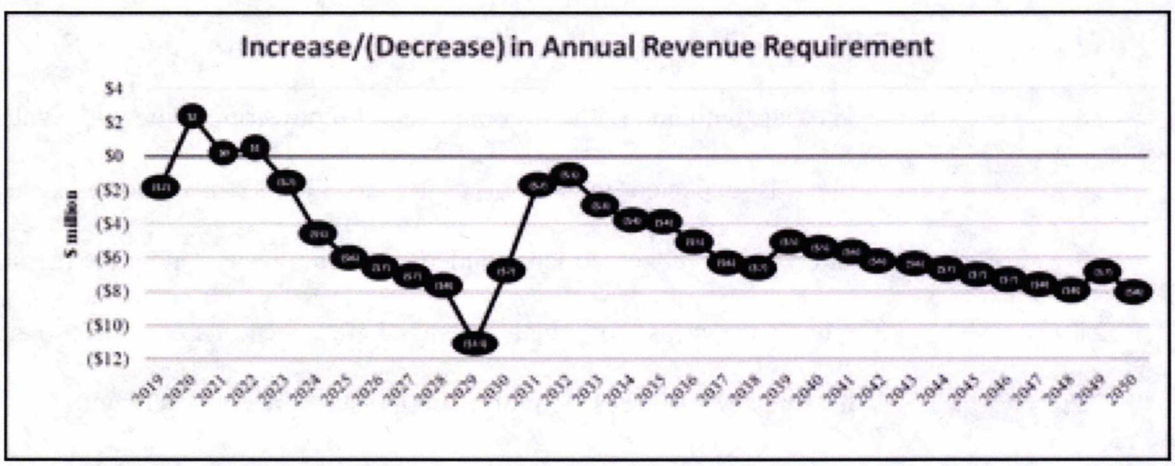
Table 1. Net Benefits from Foote Creek I Repowering

	PVRR(d) Net (Benefit)/Cost	Nom. Lev. Net Benefit ($/MWh of
Medium Natural Gas, Medium	($48.20)	$29/MWh
Low Natural Gas, No CO_2	($5.60)	$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 2 reflects the change in nominal revenue requirement associated with project costs, including capital revenue requirement (*i.e.*, depreciation, return, income taxes, and property taxes), operations and maintenance 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 2. (Reduction)/Increase in Total-System Annual Revenue Requirement from Foote Creek I Repowering



IV. NEW WIND AND TRANSMISSION

Q. Please describe the new wind and transmission projects the Company is developing as part of its EV 2020 project.

A. The EV 2020 project includes 1,150 MW of new wind facilities—Ekola Flats (250 MW), TB Flats I and II (500 MW), and Cedar Springs (400 MW). Ekola Flats and TB Flats I and II were benchmarks from the 2017R RFP. The Cedar Springs facility was offered into the 2017R RFP by a third party and is one-half build-transfer agreement and one-half power-purchase agreement. The EV 2020 project also includes the Aeolus-to-Bridger/Anticline line and transmission network upgrades needed to interconnect the wind facilities. All of the wind and transmission assets have either already come online or are expected to come online in 2021.

Q. Are you familiar with the overall cost cap established by the Commission in its review of the CPCN for these projects?

A. Yes. It is my understanding that the Company was able to reach a stipulation with the Commission's staff ("Staff") regarding the CPCN, but the issue of the cost cap was left for the Commission to determine. The Company advocated for a "soft cap," whereas Staff were in favor of a "hard cap." Both parties to the stipulation agreed that whatever form of cap the Commission determined appropriate that it was a cap set to the estimated total capital costs of the projects, or $[redacted] million. In Order No. 34104 the Commission found in favor of Staff and established a hard cap on costs for the new wind and transmission projects. In Ms. Joelle R. Steward's testimony, she describes the Commission's reasoning on finding for a hard cap in greater detail. For the purposes of my testimony, the key element of the Commission's finding for a hard cap was that the

Company's "justification [for the new wind and transmission projects] is economic in nature, as opposed to purely reliable and safe service."[2]

Q. Was the justification for the new wind and transmission projects purely economic in nature?

A. No. In the CPCN proceeding, the Company showed that its 2017 IRP identified a need for new resources. The 2017 IRP included a load and resource balance that showed PacifiCorp's summer coincident summer peak capacity position was short by 1,023 MW in 2021, the first full year that the EV 2020 wind resources were projected to be online. This short capacity position was projected to increase over the 20-year planning period. The capacity contribution of the proxy wind resources in the 2017 IRP preferred portfolio totaled 174 MW. As such, even after accounting for the capacity associated with new wind resources projected to come online by the end of 2020 in the 2017 IRP preferred portfolio, the Company's 2021 capacity position was projected to remain short by 849 MW.

In my supplemental rebuttal testimony from the CPCN proceeding, I described how an updated load forecast that was finalized after the 2017 IRP was completed did not alter the fact that the Company continued to show a need for new resources. After accounting for that more recent and lower load forecast, PacifiCorp's summer coincident peak position remained short by 595 MW in 2021. This capacity deficit was still considerably greater than the capacity contribution of the new wind facilities from

[2] In the Matter of the Application of Rocky Mountain Power for a Certificate of Public Convenience and Necessity and Binding Ratemaking Treatment for New Wind and Transmission Facilities, Case No. PAC-E-17-07, Order No. 34104, at p. 13 (Jul. 20, 2018).

the EV 2020 project.

After accounting for new resources procured after the 2017 IRP was filed, including the EV2020 wind resources, the 2019 IRP continues to show that the Company's summer coincident peak capacity position is short by 614 MW in 2021. As in the 2017 IRP, this short position grows over the 2019 IRP 20-year planning period.

Q. Have some of the projects exceeded the capital cost estimates that were combined to establish the cost cap approved by the Commission in the CPCN proceeding?

A. Yes. Mr. Hemstreet discusses how the wind project costs compared to those assumed in my economic analysis of the EV 2020 project in the CPCN proceeding and Mr. Rick Vail discusses how the transmission and network upgrade costs compare to those assumed in the CPCN proceeding. In aggregate the capital costs of EV 2020 were within 2.2 percent of the cost estimates provided in the CPCN proceeding.

Q. Despite the relatively small increase in current cost forecasts relative to the assumed costs from the CPCN proceeding, do these projects continue to show substantial customer benefits?

A. Yes. I applied the percent change in capital costs for the wind facilities and the transmission and network upgrades to capture how the change in costs for those specific line items affect the PVRR(d) presented in my supplemental rebuttal testimony from the CPCN proceeding. Table 2 shows how the PVRR(d) results are impacted for the low natural gas with no CO_2 and the medium natural gas with medium CO_2 price-policy scenarios used in the CPCN proceeding. These results are shown for the 20-year stochastic mean results through 2036 and the nominal results through 2050. No other changes were made.

Table 2. Estimated Impact of Current EV 2020 Capital Cost Forecasts

PaR Stochastic Mean PVRR(d) (Benefit)/Cost ($ million) through 2036			
Price-Policy Scenario	**PVRR(d) CPCN Supplemental Rebuttal**	**PVRR(d) Most Current Forecasted Capital Costs**	**Variance from CPCN Supplemental Rebuttal**
Low Gas, Zero CO_2	($143)	($116)	$27
Medium Gas, Medium CO_2	($338)	($311)	$27
Nominal PVRR(d) (Benefit)/Cost ($ million) through 2050			
Price-Policy Scenario	**PVRR(d) CPCN Supplemental Rebuttal**	**PVRR(d) Most Current Forecasted Capital Costs**	**Variance from CPCN Supplemental Rebuttal**
Low Gas, Zero CO_2	$154	$190	$36
Medium Gas, Medium CO_2	($174)	($138)	$36

These results show that, while the updated capital costs reduce customer benefits by $27 million in the stochastic mean results through 2036, the projected customer benefits remain significant in both price-policy scenarios. In the nominal results through 2050, customer benefits are reduced by $36 million. While the EV 2020 project continues to show potential costs in the most conservative low gas and no CO_2 price-policy scenario, the medium gas and medium CO_2 price-policy scenario continues to show significant customer benefits.

Q. Please describe how these projects contribute to the Company's duty to provide customers affordable and reliable service?

A. These assets are included in the Company's 2019 IRP, and as discussed above, the EV 2020 project is important to meeting PacifiCorp's projected capacity needs for many years to come. The EV 2020 project will generate federal PTCs, produce zero-fuel-cost energy that will lower net power costs, generate renewable energy credits which can be sold in the market to create additional revenues that would lower customer costs, and help decarbonize PacifiCorp's resource portfolio, which mitigates risk associated with potential future policies targeting greenhouse gas emissions reductions.

Q. Is it your opinion that, despite the minor cost overruns, these projects are necessary for the Company to continue to provide affordable and reliable service to customers?

A. Yes.

Q. Should the Commission approve the full costs of these projects, including the amounts in excess of its previously approved cap because these projects are necessary for the Company to provide safe and low-cost service to its customers?

A. Yes.

V. 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 as a resource decision that is least-cost and least-risk for customers. 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 renewable energy credits ("RECs") generated by Pryor Mountain over a 25-year period under PacifiCorp's Oregon Schedule 272 - Renewable Energy Rider Optional Bulk Purchase Option. The opportunity evolved over a very compressed timeline, beginning in October 2018, with final terms on all material agreements completed before September 30, 2019. In September 2019, PacifiCorp executed the Engineering, Procurement, and Construction Contractor and wind turbine supplier agreements for the project. Mr. Robert Van Engelenhoven provides additional information about this project in his testimony.

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

A. I used the same methodology to perform the economic analysis of the Pryor Mountain Wind Project as 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 timeframe. System benefits from the development of the Pryor Mountain Wind Project, which includes sale of the associated RECs in accordance with the Oregon 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 wind repowering analysis 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 CO2 price assumptions (the "LN" price-policy scenario). These assumptions are summarized in Figure 1, which is presented earlier in my testimony.

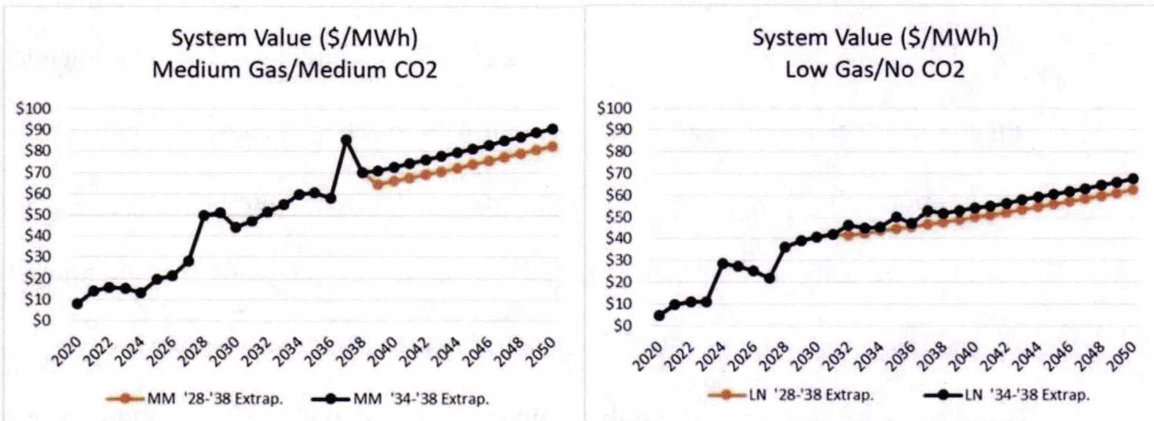
Q. Over what period did you analyze the costs and benefits of the Pryor Mountain Wind Project?

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 timeframe.

A. As with my economic analysis of Foote Creek I, 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 3.

Figure 3. 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 3 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) benefits range 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. Ms. Steward's testimony describes how Idaho's share of the benefits from the Schedule 272 agreement will flow to customers. Additionally, while not explicitly analyzed, customer benefits would increase significantly with high natural-gas price and/or high CO_2 price assumptions.

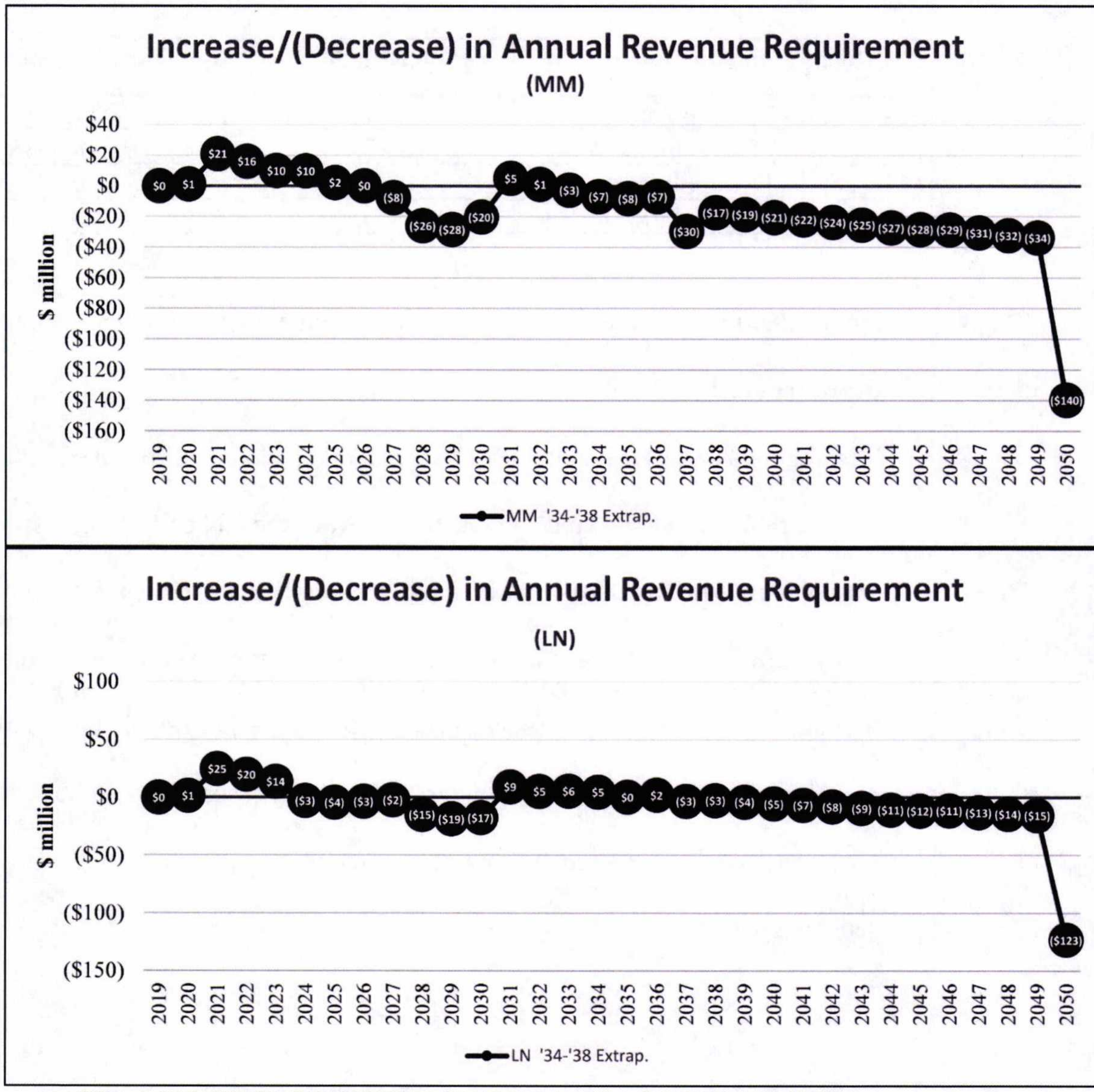
Table 3. Net Benefits from the Pryor Mountain Wind Project

Price-Policy Scenario	PVRR(d) Net	Nom. Lev. Benefit
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 4 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 4. (Reduction)/Increase in Total-System Annual Revenue Requirement from the Pryor Mountain Wind Project



VI. NAUGHTON UNIT 3 NATURAL GAS CONVERSION

Q. Have you prepared economic analysis supporting major resource management decisions for coal generation units included in this case?

A. Yes. I present economic analysis supporting the conversion of Naughton Unit 3 to natural gas in 2020.

Q. Please provide background on Naughton Unit 3.

A. The Naughton plant is located near Kemmerer, Wyoming. For several years PacifiCorp has been considering the conversion of Naughton Unit 3, a 280 MW coal-fired resource, to a natural gas facility for environmental compliance purposes. The most recent permit from the Wyoming Air Quality Division requires Naughton Unit 3 to cease coal firing by January 30, 2019, and that gas conversion be completed by June 24, 2021.

Q. Did PacifiCorp end coal generation at Naughton Unit 3 in 2019?

A. Yes. Coal generation from Naughton Unit 3 ended on January 30, 2019.

Q. Does the 2019 IRP's preferred portfolio reflect the conversion of Naughton Unit 3 to a natural gas facility in 2020?

A. Yes. In the 2019 IRP preferred portfolio, Naughton Unit 3 is converted to natural gas in 2020, providing a low-cost reliable resource for meeting load and reliability requirements. The 2019 IRP action plan provides that PacifiCorp will complete the gas conversion of Naughton Unit 3, including completion of all required regulatory notices and filings, in 2020. The conversion will retrofit the unit to a natural gas fueled, slow start peaking unit at 75 percent maximum continuous rating, with expected generation of 247 MW. In his testimony, Mr. Van Engelenhoven describes the history and status of this conversion project, which was completed by mid-2020.

Q. In the 2019 IRP, how long does PacifiCorp assume Naughton Unit 3 will operate as a natural gas facility?

A. The 2019 IRP assumes Naughton 3 will operate as a natural gas facility through 2029.

Q. Does the conversion of Naughton 3 to natural gas benefit customers over other alternatives?

A. Yes. The cost of natural gas conversion equates to approximately $12/kilowatt ("kW"). A new frame simple cycle combustion turbine located near the Naughton facility is estimated to cost $745/kW (2018 dollars). While the assumed design life of a new gas peaking asset is longer than the assumed life of Naughton Unit 3 once it is converted to a gas-fueled generating unit, the upfront capital required to convert natural gas is significantly less than the initial capital of new gas-fired generating unit. The gas conversion of Naughton Unit 3 represents an opportunity to maintain system capacity at a very low cost over a period in time where there are resource adequacy concerns in the region. PacifiCorp's analysis in the 2019 IRP demonstrates that, compared to early retirement of Naughton Unit 3, natural gas conversion has a PVRR(d) customer benefit ranging between $62 million and $121 million. The range of benefits is dependent upon the timing and magnitude of early coal unit retirement assumptions.

Q. Please explain the methods and assumptions used for the economic analysis in the 2019 IRP.

A. Portfolio development cases from the 2019 IRP explored, among other things, alternative coal unit retirement assumptions. These cases also evaluated how system costs would be impacted if Naughton Unit 3 were converted to natural gas in 2020.

Case P-09 from the 2019 IRP is a variant of case P-03 that isolates the impact of converting Naughton Unit 3 to a 247 MW gas-fired facility in 2020. Both cases assume less accelerated coal retirements relative to the 2019 IRP preferred portfolio. Through the end of 2024, the total coal capacity assumed to retire in cases P-09 and P-

03 is 280 MW, which represents Naughton Unit 3 ending coal-fired operations in 2019. Through the end of 2027, the total coal capacity assumed to retire in cases P-09 and P-03 is 1,734 MW. The PVRR of system costs in case P-09, where Naughton Unit 3 is assumed to convert to a 247 MW gas-fired facility in 2020, is $62 million lower than in case P-03.

Similarly, Case P-10 from the 2019 IRP is a variant of case P-04 that isolates the impact of converting Naughton Unit 3 to a 247 MW gas-fired facility in 2020. Cases P-10 and P-04 assume more accelerated coal retirements relative to the 2019 IRP preferred portfolio. Through the end of 2024, the total coal capacity assumed to retire in cases P-10 and P-04 is 1,730 MW. Through the end of 2027, the total coal capacity assumed to retire in these cases is 2,568 MW. The PVRR of total system costs in case P-10, where Naughton Unit 3 is assumed to convert to a 247 MW gas-fired facility in 2020, is $121 million. As compared to the PVRR(d) between cases P-09 and P-03, customer benefits are higher with the increase in accelerated coal retirements assumed in cases P-10 and P-04.

As noted above, cases developed in the initial portfolio development phase of the 2019 IRP were developed on the basis of outcomes of modeled results and stakeholder feedback. Subsequent cases produced during the initial portfolio development phase of the 2019 IRP were designed to evaluate cost and risk impacts of other variables (i.e., further analysis of coal unit retirement timing and price-policy assumptions). Based on the findings described above, subsequent cases produced in the 2019 IRP—including the case that was ultimately identified as the preferred portfolio—retained the assumption that Naughton Unit 3 is converted to a 247 MW gas-fired facility in 2020.

VII. CONCLUSION

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

A. I recommend that the Commission conclude that PacifiCorp's repowering of the Foote Creek I wind facility and the acquisition of the Pryor Mountain Wind Project are reasonable and prudent. I recommend that the full cost of the EV 2020 projects be included in rates. I also recommend that the Commission approve the costs of the resource decisions PacifiCorp has made with respect to Naughton Unit 3.

Q. Does this conclude your direct testimony?

A. Yes.