BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES IN IDAHO AND APPROVAL OF PROPOSED ELECTRIC SERVICE SCHEDULES AND REGULATIONS	)	**CASE NO. PAC-E-24-04** **DIRECT TESTIMONY OF THOMAS R. BURNS** **REDACTED**

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-24-04

May 2024

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and current position with PacifiCorp d/b/a Rocky Mountain Power (the "Company").

A. My name is Thomas R. Burns, my business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. I am currently employed as Vice President of Resource Planning and Acquisitions for PacifiCorp.

Q. Please describe your education and professional experience.

A. I graduated from Illinois State University with a Bachelor of Science degree in Economics. I joined PacifiCorp in 2007 and assumed the responsibilities of my current position in September 2022. Over this period, I held several operational, analytical and leadership positions within the Company. My previous role with PacifiCorp was Director of Energy Supply Management, Operations, and Reliability. In that role I was instrumental in the design and implementation of the Western Energy Imbalance Market.

Q. Briefly describe the responsibilities of your current position.

A. I am responsible for PacifiCorp's resource planning and procurement functions, which include the integrated resource plan ("IRP"), structured commercial business and valuation activities, and long-term load forecasts. Most relevant to this general rate case, I oversee the planning, analysis, and outreach processes that are used to develop PacifiCorp’s IRP, and the economic analysis that helps guide the Company’s resource acquisitions.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony in this case?

A. I provide economic analysis that supports PacifiCorp’s decisions to: acquire the 190-megawatt (“MW”) Rock Creek I wind facility; and acquire and repower the 43 MW Foote Creek II-IV and 50 MW Rock River I wind facilities in Wyoming.

I also summarize PacifiCorp’s assessment of the projects from the 2021 IRP and IRP Update, 2020 All-Source Request for Proposals (“2020AS RFP”), and customer benefits that result from these projects.

Q. Please provide an overview of your testimony for Rock Creek I.

A. My economic analyses show that the project is in the public interest and will generate significant benefits for Idaho customers across all scenarios. Analysis prepared before passage of the Inflation Reduction Act (“IRA”) showed risk-adjusted benefits ranging from a present-value revenue requirement differential (“PVRR(d)”) $2 million benefit to customers in the low natural gas, no carbon scenario, to a $20 million benefit in the medium natural gas, medium carbon scenario.

The post-IRA analysis of both Rock Creek I and Rock Creek II (a co-located sister facility that the Company analyzed together with Rock Creek I after passage of the IRA) yields customer benefits totaling $298 million, that rise to $318 million on a risk-adjusted basis under an MM price-policy scenario. Conservatively, these benefits do not assign any value to the renewable energy certificates ("RECs") that will be generated by Rock Creek I and Rock Creek II, which can provide additional customer benefits if sold, transferred, or used to comply with relevant state requirements.

Q. Please provide an overview of your testimony for Foote Creek II-IV and Rock River I repowering projects.

A. My economic analyses indicate that these projects are in the public interest and will generate benefits for Idaho customers.

Benefits for Foote Creek II-IV range from $53.07 million when using medium natural gas and medium carbon dioxide ("CO_2") assumptions to $142.77 million for high natural gas and the social cost of greenhouse gases assumptions prior to adjusting for benefits from the IRA. This is compared to a $17.09 million customer cost in the LN scenario. These benefits increase to $76.49

million when using medium natural gas and medium CO2 assumptions and $104.23 million for high natural gas and high CO2 assumptions when factoring in the IRA. Importantly, the only scenario where Foote Creek II-IV was expected to generate customer costs prior to passage of the IRA—the LN scenario ($17.09 million)—has transformed to a $6.33 million customer benefit. These benefits only increase under the highest cost of carbon scenario (MM-SCGHG).

Similarly, benefits for Rock River I range from $30.15 million when using medium natural gas and medium CO_2 assumptions to $67.76 million for high natural gas and high CO_2 assumptions before adjusting for the IRA. When factoring in the IRA, these benefits increased to $54.09 million when using medium natural gas and medium CO_2 assumptions and $91.69 million for high natural gas and high CO_2 assumptions.

Like Rock Creek I, the analyses of both facilities does not assign any value to the RECs that will be generated by either Foote Creek II-IV or Rock River I, which will provide additional customer benefits if sold, transferred, or used to comply with relevant state requirements.

III. ROCK CREEK I

Q. Please generally describe the Rock Creek I.

A. As described in the confidential testimony of Company witness Jeffrey M. Wagner, PacifiCorp is acquiring the 190 MW Rock Creek I project under a build-transfer agreement ("BTA") from Invenergy, and will be transferred to the Company after construction is complete. My testimony provides the economic justification for the Company's decision to acquire this project.

A. Resource Need

Q. Please provide an overview of the Company's IRP process.

A. PacifiCorp's IRP process uses thorough analysis and modeling that measures cost and risk to develop the Company's plans to provide reliable and reasonably priced service for its customers. The primary objective of the IRP is to identify the least-cost, least-risk portfolio of resources that can serve customers in the future with manageable risks.

The Company completes an IRP cycle every two years (odd-numbered years), which includes preparing a full IRP every two years and an update to the full IRP in the off years (even-numbered years). The Company submits both its IRP and IRP Update to each of the six regulatory commissions in the states where the Company provides retail service. Each IRP is developed through an open and public process, with input from an active and diverse group of stakeholders, including state regulatory commissions, state consumer-advocacy departments, customer-sponsored advocacy groups, environmental-advocacy groups, resource-advocacy groups, independent-power producers, project developers, other utilities, and customers. During the public-input process, which typically spans at least a full year before the release of a full IRP, PacifiCorp holds regular meetings with stakeholders to solicit feedback on the Company's planning assumptions, methodologies, and model results.

Q. Did the Company's 2021 IRP identify a need for additional resources to serve PacifiCorp's customers?

A. Yes. The primary focus of any IRP is to forecast the need for resources and evaluate different strategies to meet that need over time. The Company's 2021 IRP indicated that PacifiCorp has a capacity deficit in all years of the planning horizon—starting at 1,071 MW in 2021 and increasing to over 6,600 MW by 2040. In 2025, the resource need in the 2021 IRP is 1,627 MW. As described further below, this need has increased since the 2021 IRP was released.

Q. How does the 2021 IRP preferred portfolio address the need for new resources?

A. The 2021 IRP preferred portfolio represents PacifiCorp's least-cost, least-risk plan to reliably meet customer demand over a 20-year planning period. Using a range of cost and risk metrics to evaluate numerous resource portfolios, PacifiCorp selected a preferred portfolio that reflects a cost-conscious plan that includes near-term investments in renewable resources that can capture tax credits before they expire or decrease, and new transmission infrastructure to facilitate the interconnection and delivery of these resources. These new resources and transmission investments are lower cost than other resource and transmission alternatives and are necessary to reliably serve our customers.

Q. Can you describe the methodology that PacifiCorp used in the 2021 IRP to analyze the economics of the preferred portfolio?

A. Yes. PacifiCorp incorporated a new and more advanced optimization modeling system called PLEXOS. The PLEXOS modeling system provides three platforms (referred to as Long-term ("LT"), Medium-term ("MT") and Short-term ("ST")), which work on an integrated basis to inform the optimal combination of resources by type, timing, size, and location over PacifiCorp's 20-year planning horizon.

Please refer to Company witness Rick T. Link's testimony for additional detail regarding PLEXOS and the LT, MT, and ST platforms.

Q. Does PacifiCorp have a need for Rock Creek I?

A. Yes. As discussed above, the 2021 IRP preferred portfolio indicated a demonstrated need for new resources. The Company proposed to begin addressing this need through 1,792 MW of new wind generation resulting from the 2020AS RFP, which included Rock Creek I.[1]

Q. Please describe key factors that support including Rock Creek I in PacifiCorp's 2021 IRP preferred portfolio.

A. The project is expected to meet the Company's near-term resource need and provide significant customer benefits by providing zero-fuel cost generation and substantial production tax credit ("PTC") benefits, while mitigating risks associated with future regulation of carbon-emitting resources.

Q. Please describe the reliability benefits of projects like Rock Creek I.

A. Rock Creek I reduces the Company's exposure to price and volume volatility by reducing the need for market purchases. Increased reliance on the market exposes customers to price volatility and price spikes that occur when the region experiences severe weather events

[1] 2021 IRP, Vol. I, Ch. 9.

or system disruptions. Such events increase net power costs, and the magnitude of increase is directly proportional to the volume of purchases needed. In short, there is no guarantee that there will be a seller when PacifiCorp needs to make a short-term purchase to serve its load. This risk also exists for firm forward market purchases, where the seller could cut scheduled deliveries and accept liquidated damages if they do not have sufficient supply to meet their contractual obligations of the sale. As discussed in Company witness Link's testimony, Western Electricity Coordinating Counsel and North American Electric Reliability Corporation ("NERC") reliability studies highlight the risks of resource shortfalls across the region in the coming years.

Q. How do these studies relate to Rock Creek I?

A. Each of these studies confirm the generally accepted understanding that the west is facing increasing resource adequacy risks in the near term. More recently, NERC further confirmed these findings and warned in its 2022 Summer Reliability Assessment that several regions in North America were at high or elevated risk of power outages this past summer due to above-normal temperatures and drought conditions, particularly in the western half of Canada and the United States.[2]

Rock Creek I will help mitigate the risk that there may be inadequate supply to support market purchases and reduce exposure to price spikes in periods where demand threatens to exceed supply for market purchases.

Q. Was Rock Creek I selected in the 2020AS RFP?

A. Yes. As discussed in Company witness Link's testimony, the 2020AS RFP final shortlist included six final shortlist bids representing over 1,600 MW of wind generation that seek to interconnect to PacifiCorp's transmission system. These bids include Rock Creek I which, with Rock Creek II, were the only two bids that were not power purchase agreements.

Q. Following its selection in the 2020AS RFP final shortlist, did the Company begin negotiating a BTA for Rock Creek I?

A. Yes. As discussed by Company witness Wagner, the Company engaged in BTA negotiations with Invenergy for the project.

[2] 2022 Summer Reliability Assessment, North American Electric Reliability Corporation (May 2022) (https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2022.pdf).

Q. Were negotiations impacted by current economic conditions?

A. Yes. Bidder development efforts were challenged by importation restrictions related to China, COVID-19 international impacts, and hostilities in Ukraine that created significant logistics and supply chain challenges associated with solar panels, wind turbines, lithium batteries, transformers, and many balance-of-plant materials. As a result, many developers have been forced to abandon established supply chains and revert to new suppliers (if available), which has materially impacted overall renewable power plant pricing and commitments toward project in-service dates.

Given PacifiCorp's need for generation resources, PacifiCorp allowed pricing adjustments from all final shortlist projects from the 2020AS RFP, as well as limited extensions to commercial operations dates. Despite this additional flexibility, some of the bids from the final shortlist were unable to provide firm prices and were not available for selection. This contributed to an under procurement of 902 MW of solar capacity and 497 MW of battery capacity.

Q. Have current economic conditions impacted costs for Rock Creek I compared to the costs from initial bids?

A. Yes. Given the market dynamics discussed above, the overall costs for Rock Creek I has increased from its initial bid in the 2020AS RFP. My economic analysis below is based on updated project costs.

Q. Were there any additional benefits associated with Rock Creek I that offset these increased costs?

A. Yes. PacifiCorp's original economic analysis in the 2020AS RFP assumed that Rock Creek I qualified for a 60 percent PTC through the first 10 years of operation. As a result of the IRA, the economic analysis in this case reflects the value of the 110 percent PTC, in addition to the updated project costs. These updates cause a significant and positive change in the economic benefits of the project.

Q. Have current economic drivers also impacted the Company's resource needs?

A. Yes. While the costs of 2020AS RFP bids have increased, the Company's resource needs have also increased. It is also important to consider the broader regional capacity need that aligns with the Company's need and expected in-service date for Rock Creek I. The 2020AS RFP included virtually every potential non-market resource in the region capable of achieving commercial operation by 2025. Meeting this near-term need with physical assets that will provide incremental generation capacity effectively limits the Company's options to bidders in the 2020AS RFP.

Therefore, the 2020AS RFP bids and Rock Creek I remain necessary to reliably serve Idaho customers, and Rock Creek I selection in the RFP confirms it is part of the least-cost, least-risk resources available to meet the Company's need.

Q. Did the Company prepare an update to the 2021 IRP?

A. Yes. On March 31, 2022, the Company issued its 2021 IRP Update.[3]

Q. What is the purpose of the 2021 IRP Update?

A. The IRP update is a checkpoint on the 2021 IRP action plan and ensures that changes in the planning environment are considered between the two-year IRP planning cycle. The 2021 IRP Update assessed whether evolving trends and events impact customers and required changes to the action plan to deliver resources and transmission investments. Relevant here, the 2021 IRP Update reflects resource planning and procurement activities that occurred since the 2021 IRP, and present an updated load-and-resource balance and an updated resource portfolio.

[3] PacifiCorp 2021 Integrated Resource Plan Update (Mar. 31, 2022) (https://www.pacificorp.com/energy/integrated-resource-plan.html).

Q. Was Rock Creek I included in the Company's 2021 IRP Update preferred portfolio?

A. Yes.[4]

Q. Where there any important modeling updates in the 2021 IRP Update?

A. As discussed in Chapter 5 of the 2021 IRP Update, key updates in addition to the load-and-resource balance include the resource changes due to 2020AS RFP activity, which is discussed further below. Importantly, the EPA's pre-publication version of the OTR, released on March 11, 2022, was not modeled in the 2021 IRP Update.

Q. Did the 2021 IRP Update continue to show a need for additional generation resources?

A. Yes. As discussed in Company witness Link's testimony, the need increased due to an increase in forecast load. The 2021 IRP Update shows a resource need in all years of the planning horizon—starting at 1,584 MW in 2022 and increasing to 6,755 MW in 2040. In 2025, the resource need is 1,867 MW, an increase of 240 MW, or approximately 15 percent, relative to the resource need identified in the 2021 IRP. The higher load reflected in the 2021 IRP Update approaches the level analyzed in the high-load sensitivity conducted in the 2021 IRP. The most recent

[4] *Id.*at Ch. 7, Action Item 2e, at 103 (Mar. 31, 2022).

load forecast is even higher than that assumed in the 2021 IRP Update.

Moreover, now that the 2020AS RFP has ended, PacifiCorp was unable to execute firm contracts with all projects on the final shortlist. Due to national tariff policies, global supply-chain issues, and inflationary pressures, some projects on the 2020AS RFP final shortlist were unable to move forward. Consequently, PacifiCorp's procurement was reduced by 902 MW of solar resources and 497 MW of battery storage resources. This under-procurement adds to our need for new resources.

Q. Does the 2021 IRP Update consider the reliability issues related to reliance on market purchases?

A. Yes. Given near-term concerns over resource adequacy, and because of the acquisition of additional resources including Rock Creek I, the 2021 IRP Update's preferred portfolio shows generally lower market purchases in the first five years relative to the 2021 IRP preferred portfolio.[5]

B. Modeling Assumptions and Methods

Q. Did the Company analyze Rock Creek I and Rock Creek II together?

A. Yes, for the most part. As stated above, there were two BTA wind facilities in the Company's final shortlist of

[5] *Id.* at Figure 1.11.

projects: Rock Creek I and Rock Creek II. The second facility is a larger wind facility, at 400 MW compared to Rock Creek I at 190 MW. In previous regulatory proceedings, the Company analyzed the wind projects together to determine whether acquiring the projects would provide net benefits to customers. This was reasonable, because the projects are co-located with each other and share the same modeling assumptions.

In this proceeding the Company is only requesting rate recovery of Rock Creek I, because Rock Creek II has an in-service date that falls outside the test period of this rate case. Nonetheless, several of the analyses below include combined results from both wind projects, as well as Rock Creek I specific analyses. This allows the Commission to examine both the additive benefits that will occur when wind projects are interconnected to PacifiCorp's system, but also the Rock Creek I specific customer benefits that inform the Company's revenue requirement in this proceeding.

Q. Please summarize the natural gas and CO_2 price assumptions used in the economic analysis of Rock Creek I.

A. The economic analysis of Rock Creek I included three price-policy scenarios—medium natural gas paired with medium CO2 prices ("MM"), medium natural gas prices without a CO_2 price ("MN"), and low natural gas without a CO_2 price ("LN") price-policy scenarios. While the MM price-policy scenario represents the Company's "expected case" describing likely future conditions, the additional scenarios provide additional helpful analyses.

These assumptions influence 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 associated with Rock Creek I. Because wholesale power prices and CO_2 policy outcomes are both uncertain and important drivers to the economic analysis, it is important to evaluate a range of assumptions for these variables. Table 1 summarizes the price-policy scenarios.

Table 1. Price-Policy Scenario Assumption Overview

Price-Policy Scenario	Henry Hub Natural Gas Price (Levelized $/MMBtu)*	CO_2 Price Description
MM	$4.52	$12.10/ton starting 2025 rising to
MN	$4.52	None
LN	$2.92	None
*Nominal levelized Henry Hub natural gas price from 2025 through 2040.		

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

A. The medium natural gas price assumptions are from PacifiCorp's official forward price curve ("OFPC") dated June 30, 2022, which was the most current OFPC available when PacifiCorp prepared its modeling inputs for the 2020AS RFP. The first 36 months of the OFPC reflect market forwards at the close of a given trading day (June 30, 2022 in this case). As such, these 36 months are market forwards as of June 2022. The blending period (months 37 through 48) is calculated by averaging the month-on-month market forwards from the prior year with the month-on-month fundamentals-based price from the subsequent year. The fundamentals portion of the natural gas OFPC reflects Aurora-forecast prices.

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

A. PacifiCorp used two different CO_2 price scenarios—zero and medium. The medium scenario is derived from a survey of third-party industry experts, including IHS CERA, and Wood Mackenzie and the Energy Information Administration as well as CO_2 price assumptions used by peer utilities. The resulting CO_2 price is applied as a tax beginning in 2025.

Q. Does including potential future CO_2 costs reflect prudent utility planning?

A. Yes. The Company's price-policy scenarios include varying levels of assumed CO_2 costs to reflect the fact it is more likely than not that some policy will exist that will reduce emissions for carbon emitting resources. When determining CO_2 costs used for planning purposes, the Company strives to ensure that it is not an outlier, and the medium price is within a reasonable range used by the industry to assess risk and conduct prudent resource planning. The most recent example of this trend is the Environmental Protection Agency's ("EPA") proposed Ozone Transport Rule ("OTR") restricting nitrogen oxide ("NO_X") emissions from power plants and other industrial sources. At the time the Company conducted its economic analyses, this rule would have imposed new environmental compliance obligations beginning in 2023 and 2024 on coal units in Utah and Wyoming, respectively, with more severe limitations applicable in both states by 2026.[6]

Q. Are the modeled CO_2 costs intended to represent a literal carbon tax?

A. No. The modeled CO_2 costs are not intended to explicitly account for a future tax on CO_2 emissions. Rather, these costs capture the effect of policies incentivizing reduced emissions through benefits or imposing costs through penalties or other costs resulting from market dynamics driving the need for zero-emission resources or customer preferences.

Q. Did PacifiCorp update its load forecast in its analysis of Rock Creek I?

A. Yes. The Company used a sales and load forecast that was completed in May 2022.

Q. How does the May 2022 forecast compare to the load forecast used in the 2021 IRP?

A. Figures 1 and 2 show PacifiCorp's May 2022 load and peak forecast relative to the 2021 IRP before incremental

[6] While these requirements are now subject to further federal litigation and agency review (*see, e.g., Wyoming, et al., v. United States Environmental Protection Agency, et al.*, 78 F4th 1171 (10th Cir. 2023) (OTR vacated and remanded in part); *Utah, et al., v. United States Environmental Protection Agency, et al.*, No. 23-9509 (Jul. 27, 2023) (staying OTR until final resolution for Utah)), the Company's economic analyses reflects then-current assumptions that the OTR would be in effect.

energy efficiency savings. A higher load forecast is being driven by new industrial and commercial customer growth, increased air conditioning saturations and miscellaneous devices and electric vehicle adoption expectations. The updated load forecast also accounts for updates to weather, temperature, and line losses to account for the progression of historical data since the load forecast that informed the 2021 IRP.

On average, over the 2023 through 2040 timeframe, forecast system load is up 13.6 percent per year and forecast coincident system peak is up 14.1 percent per year when compared to the 2021 IRP. Over that same timeframe, the average annual growth rate for the May 2022 forecast, before accounting for incremental energy efficiency improvements, is 2.04 percent for load and 1.66 percent for peak.

Figure 1. Forecast Annual System Load

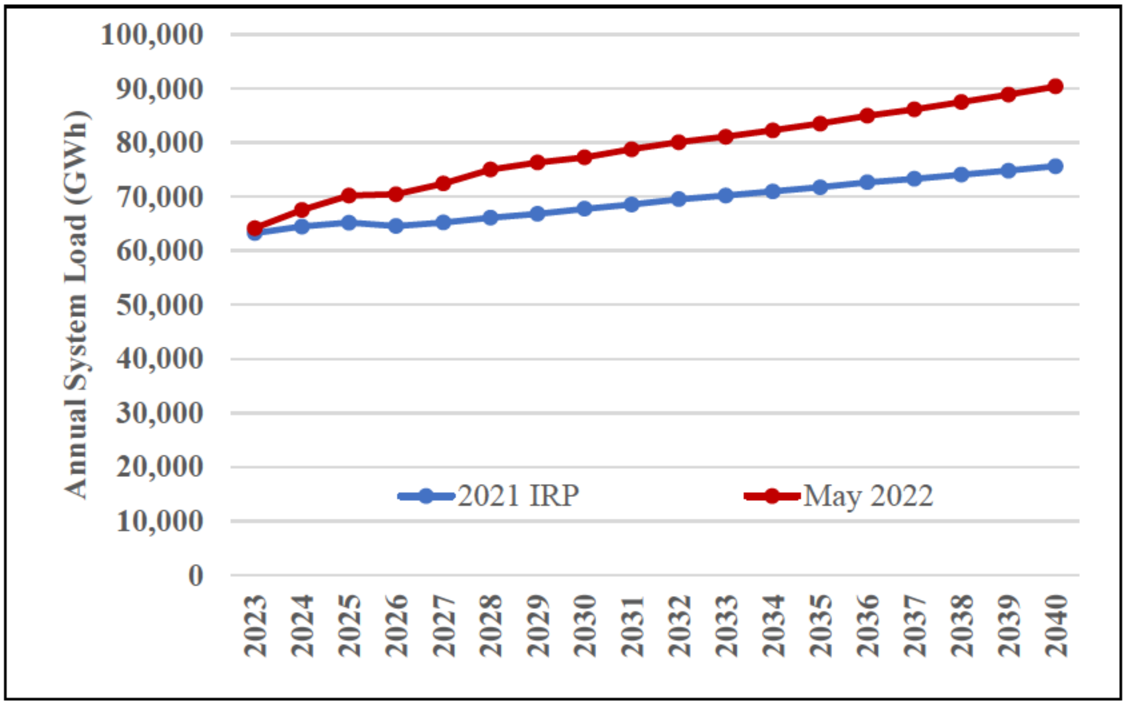
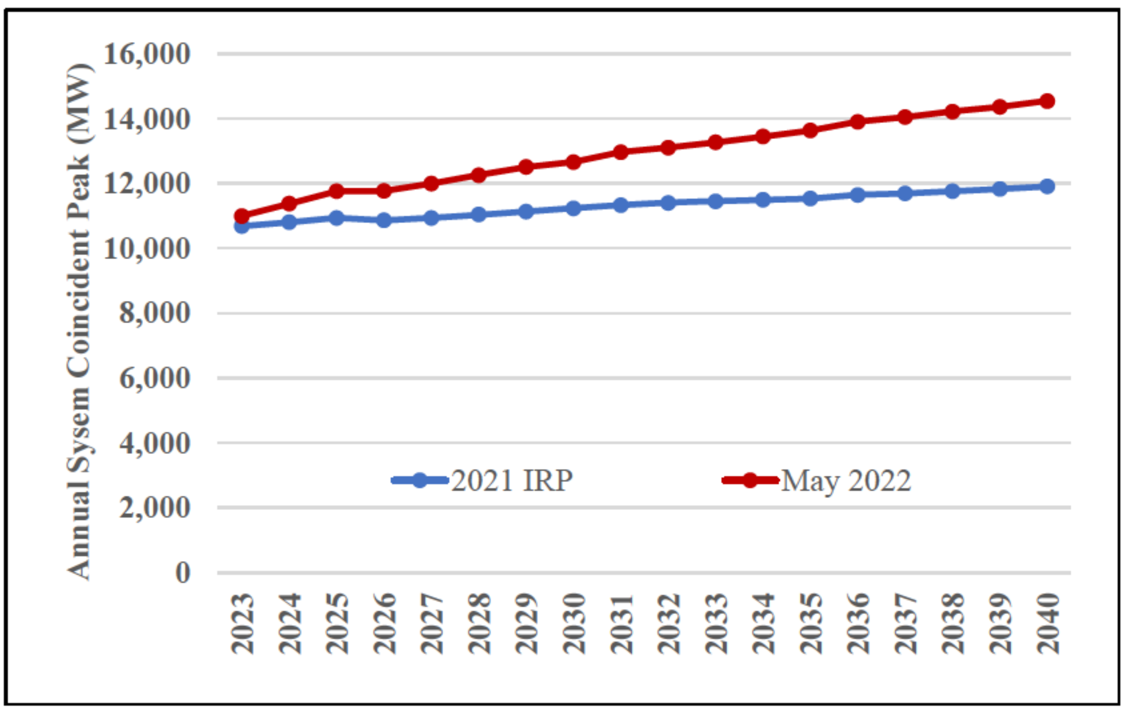


Figure 2. Forecast Annual System Coincident Peak



Q. Has PacifiCorp incorporated the EPA's proposed OTR in its analysis of Rock Creek I?

A. Yes. PacifiCorp modeled two primary components to reflect the OTR: NO_X allowance requirements for each of its units including penalties for units with high emissions rates, and a dispatch target or shadow price for NO_X allowances, which is used to avoid producing NO_X emissions during periods when the economic benefits are relatively low. After running the model, PacifiCorp compared the results to forecasts of its annual allocation of NO_X allowances for Utah and Wyoming.

Q. Please describe how the annual allocation of NO_X allowances would work under the proposed rule.

A. The proposed rule calls for dynamic budgeting of NO_X allowances in 2025 and beyond, with available allowances allocated among resources within a state based on the recent historical heat input and emissions rates of each resource. Under the EPA's proposed rule, the forecast allocation of NO_X allowances drops significantly in 2026, as the EPA assumed that selective catalytic reduction ("SCR") installations at eligible facilities would significantly reduce emissions by that year. PacifiCorp's thermal facilities in Utah would be covered by the rule beginning 2023 and thermal facilities in Wyoming could be covered by the rule beginning 2024.

While trading of NO_X allowances among participating states is allowed, the proposed OTR includes significant penalties if a state's emissions exceed 121 percent of its annual allocation. Limited banking of NO_X allowances is also allowed, but emissions met via banked allowances may also be subject to penalties if a state's emissions exceed 121 percent of its annual allocation. To avoid such penalties, PacifiCorp's NO_X emissions during the ozone season (May-September) in each state cannot exceed 121 percent of PacifiCorp's forecast allocation of NO_X allowances for that state.

Q. Please describe how PacifiCorp developed NO_X allowance requirements for each of its units.

A. In general, an allowance for one ton of NO_X emissions would allow the holder of the allowance to emit one ton of NO_X. However, starting in 2027,[7] the proposed OTR also imposes a daily NO_X emissions rate limit of 0.14 pounds-per-million British thermal units ("lb/MMBtu") for each coal-fired facility, and requires emitters to provide an equivalent of triple allowances for any emissions that exceed that rate. For example, a resource with an emissions rate of 0.20 lb/MMBtu would have an effective

[7] Coal units that currently have SCR installed must meet the daily backstop limit in 2024. Coal units that do not currently have SCR installed must meet the daily backstop limit in 2027.

allowance requirement of 0.32 lb/MMBtu.[8] To calculate PacifiCorp's NO_X allowance requirements under the OTR, starting in 2027 the modeled emission rates for coal resources whose emissions exceed 0.14 lb/MMBTU were grossed up to account for the additional surrender of allowances.

Q. Please describe how PacifiCorp developed a dispatch target to manage its NO_X allowance requirements.

A. While trading is allowed under the EPA's proposed OTR, the restrictions on inter-state transfers limit the number of potential counterparties. PacifiCorp's generation fleet is an appreciable portion of the electric generating units in both Utah and Wyoming, so the potential counterparties that could have allowances available for sale within those states is quite limited. With that in mind, PacifiCorp's current planning assumes that it will comply with the OTR using only its own combined allocation of NO_X allowances and is meant to ensure that its annual allowance requirements do not exceed 100 percent of the sum of its Utah and Wyoming allowance allocations. When combined with state-specific limits previously described, while either PacifiCorp's Utah or Wyoming NO_X allowance requirements could be up

[8] Effective allowance requirement for resource with emissions rate of 0.20 lb/MMBTU: 100% * 0.20 lb/MMBtu + 200% * (0.20 – 0.14) lb/MMBtu = 100% *0.20 + 200% * 0.06 = 0.32 lb/MMBtu.

to 121 percent of that state's allocation, any increase in one state would have to be accompanied by a reduction in emissions allowance requirements from PacifiCorp resources in the other state.

PacifiCorp's primary production cost analysis relies upon PLEXOS ST modeling that identifies system costs for a single deterministic set of expected or normal input conditions. In reality, and in stochastic modeling the Company performs using the PLEXOS MT model, significant variations in inputs such as load, hydro generation, and thermal availability are a normal course of operations. Each of these inputs can unexpectedly increase PacifiCorp's need for NO_X emission allowances. Because banking and trading are limited under the OTR, variations in NO_X emissions that might otherwise average out over time must comply in every year and under every set of conditions. As a result, the NO_X allowances used under "normal" input conditions will likely need to be somewhat below the forecast limit to ensure sufficient allowances are available to meet unexpected input conditions.

PacifiCorp's analysis indicated that using a NO_X allowance dispatch target of [redacted] in the ST model would result in NO_X allowance requirements that were under PacifiCorp's forecast allocation and would leave sufficient allowances to meet a range of potential "above-normal" conditions. Whenever the incremental value of using a high NO_X emitting resources exceeds the dispatch target price, the model will deploy the high NO_X resource, rather than lower NO_X alternatives, which are typically gas-fired resources or market transactions. For a coal-fired resource with a NO_X emissions rate of 0.20 lb/MMBtu, the NO_X dispatch target price means that the resource would not be dispatched unless it provides at least [redacted] in incremental value relative to no NO_X alternatives, or a proportional amount of incremental value relative to lower NO_X alternatives.[9]

The dispatch target price is used to direct the model to avoid emissions, and is not a direct cost, as the Company would receive its allowance allocation free of charge under the proposed rule. While the Company could potentially sell allowances, there is little indication what market prices may prevail, and market prices may be below this target. As a result, no direct costs or revenues for allowances are included in the analysis. The allowance requirements resulting from this

[9] A 0.20 lb/MMBTU coal-fired resource would have a NO_X credit requirement of 0.32 lb/MMBTU in 2027 and beyond, as detailed in footnote 22. A typical average heat rate for a coal-fired resource is 11 MMBtu/MWh. [redacted] ÷ 2,000 lb/ton * 0.32 lb/MMBtu * 11 MMBtu/MWh = [redacted].

dispatch target price vary over time as the OTR requirements take full effect and as the Company's portfolio evolves. The Company's load forecast and other modeling inputs also play a role in the resulting volumes. A comparison of the allowance requirements for the scenarios relative and forecast allowance allocations is discussed in the Price-Policy Scenario Results section later in my testimony.

Q. Please describe the modeling methodology PacifiCorp used in its analysis of Rock Creek I.

A. Consistent with IRP modeling practices, the Company calculated a system PVRR by identifying least-cost resource portfolios and dispatching system resources through 2040, which aligns with the 20-year forecast period used in the 2021 IRP and 2021 IRP Update. Net customer benefits are calculated as the PVRR(d) between different simulations of PacifiCorp's system. One simulation includes Rock Creek I (and in the combined studies, both Rock Creek I and II), and the other simulation excludes them. The simulation that includes Rock Creek includes transmission interconnection costs. When the two simulations are compared, changes to system costs are attributable to Rock Creek. These studies also include simulations before and after passage of the IRA, to reflect the value of increased PTCs.

PacifiCorp also calculated a PVRR(d) based on one simulation that includes only Rock Creek I and compares it to a simulation that excludes both Rock Creek projects, and one simulation that includes only Rock Creek II and compares it to a simulation that excludes both Rock Creek projects. In all studies, the Gateway West and Gateway South transmission projects discussed in Company witness Link's testimony were assumed to be in-service, and beyond 2025 proxy resource options from the 2021 IRP are available to meet system needs.

Customers are expected to realize benefits when the system PVRR from the simulation with the projects is lower than the system PVRR without. Conversely, customers would experience increased costs if the system PVRR with the projects is higher than the system PVRR without.

Q. What portfolios did you analyze using the PLEXOS model in this case?

A. Portfolios were analyzed with and without both projects, with and without Rock Creek I, and with and without Rock Creek II, including certain results pre-IRA and post-IRA.

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

A. Yes. PacifiCorp analyzed sensitivities that quantify how changes in capital costs and PTC values influence projected customer benefits.

C. Price-Policy Scenario Results

Q. Please summarize the pre-IRA results for the simulations that focused on each Rock Creek project individually.

A. Tables 2 and 3 summarize the PVRR(d) results for each price-policy scenario for the scenarios that examined each of the Rock Creek projects prior to passage of the IRA.[10]

[10] *See also* Confidential Exhibit No. 32

Table 2. Pre-IRA (Benefit)/Cost of Rock Creek I ($ million)

Price-Policy Scenario	PVRR(d)	Risk-Adjusted PVRR(d)
MM	(15)	(20)
MN	(9)	(15)
LN	3	(2)

Table 3. Pre-IRA (Benefit)/Cost of Rock Creek II ($ million)

Price-Policy Scenario	PVRR(d)	Risk-Adjusted PVRR(d)
MM	(24)	(33)
MN	(14)	(24)
LN	8	(3)

Rock Creek II generally provides a larger benefit, because it is approximately twice the size of Rock Creek I. All the same, under the MM price-policy scenario, Rock Creek I lowers total-system costs by $15 million, and adjusted for risk these benefits increase to a $20 million reduction in system costs. System benefits generally mirror the results seen in Table 4 when both projects were considered together, with a slight cost for Rock Creek I and Rock Creek II in the LN scenario prior to adjusting for risk and benefits in each of the other scenarios. Both projects, when evaluated individually, yield benefits on a risk-adjusted basis among all three price-policy scenarios.

Q. Why did PacifiCorp decide to update its economic analysis after passage of the IRA?

A. Based on existing law, PacifiCorp's economic analysis assumed that Rock Creek I and II qualified for 60 percent of available PTCs through the first 10 years of operation. After passage of the IRA, the Company understands that both Rock Creek projects qualify for 110 percent of available PTCs. This provides a significant increase to the economic benefits from the projects, and the Company's updated analysis reflects those benefits. The Company also updated its analysis to reflect current project costs.

Q. Please summarize the PVRR(d) results post-IRA.

A. Table 4 summarizes the PVRR(d) results for each price-policy scenario from the combined projects after passage of the IRA.[11]

[11] *See also* Confidential Exhibit No. 33.

Table 4. Post-IRA (Benefit)/Cost of Rock Creek I and II ($ million)

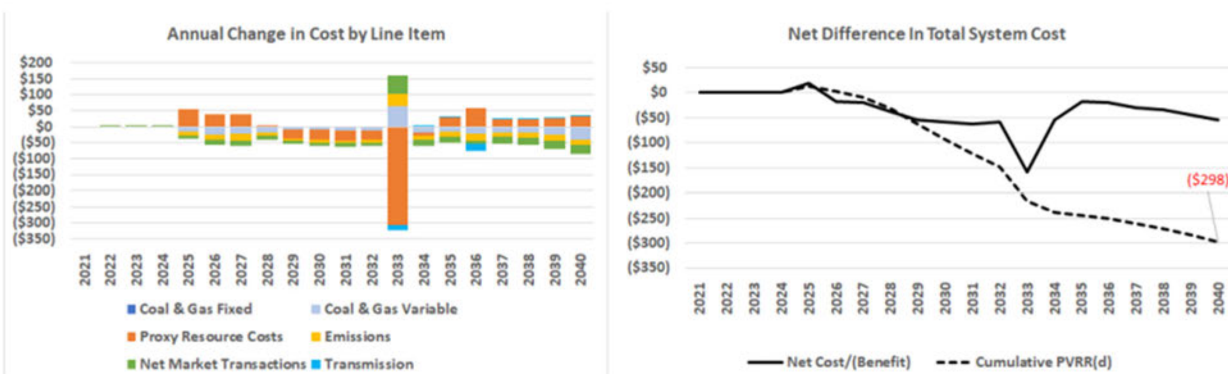
	(a)	(b)	(c)	(d)	(e) = (c) + (d)	(f) = (a) + (e)	(g) = (b) + (e)
Price-Policy Scenario	**PVRR(d)**	**Risk-Adjusted PVRR(d)**	**110% PTC Update**	**Project Cost Update**	**Total Update**	**Updated PVRR(d)**	**Updated Risk-Adjusted PVRR(d)**
MM	(143)	(163)	(197)	42	(155)	(298)	(318)
MN	(33)	(51)	(194)	42	(151)	(185)	(202)
LN	16	2	(195)	42	(153)	(137)	(151)

Before adjusting for risk (Column (f)), system costs are lower when the wind projects are included in the portfolio in all scenarios: ranging from a $137 million customer benefit under the LN scenario to $298 million in the MM scenario. When adjusting for risk (Column (g)), the benefits from the wind projects increase: ranging from $151 million in the LN scenario to $318 million in the MM scenario. The increase in customer benefits from the 110 percent PTC is substantial, even when accounting for the increase in project costs. This updated analysis supports the necessity of Rock Creek I and indicates it will produce robust customer benefits. As discussed earlier, these benefits only increase under a high gas or a high CO_2 price-policy scenario.

Q. How do system costs change post-IRA with and without both projects?

A. Figure 3 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when both projects are eliminated from the portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2040, the PVRR(d) shows that the portfolio that includes both projects is $298 million lower cost than the portfolio without both.

Figure 3. Increase/(Decrease) in System Costs when both Projects are Removed from the Portfolio ($ millions) Medium Gas/Medium CO2



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

A. For both projects, the risk-adjusted medium gas medium CO_2 PVRR(d) results show a benefit of $318 million, which is higher than the reported ST-model PVRR(d) results of $298 million prior to the risk adjustment. This indicates that the wind projects provide stochastic risk benefits by making the system less susceptible to low-probability combinations of load, market price, hydro generation, and thermal outage volatility that can increase system costs.

Q. How do the modeled OTR allowance requirements compare to PacifiCorp's forecast allowance allocation?

A. The annual allowance requirements in the ST-model results are generally slightly below a high estimate of PacifiCorp's allowance allocation. Based on the allocation methodology identified in the proposed rule, this high allowance allocation would likely require installation of SCR equipment at most of PacifiCorp's coal-fired generating units that are not equipped with that technology. In the absence of additional emission control equipment, PacifiCorp's allocation would be significantly lower, and well below the allowance requirements from the ST-model results. The high and low allocation forecasts and the ST-model results for the MM and MN price-policy scenarios are shown in Confidential Figure 4. As shown, allowance allocations could be significantly lower than what is assumed to be available in the current ST-model results, which would further increase the value of generation from resources without emissions, such as Rock Creek I and II.

Confidential Figure 4. Forecast OTR Allocation and Modeled Requirements

[redacted]

Q. Would Rock Creek I provide customer benefits even if construction costs are higher than expected?

A. Yes. For both projects, a one percent increase in the initial capital costs would reduce PVRR benefits through 2040 by $9.1 million. To negate the $318 million in risk-adjusted, post-IRA benefits under the MM price-policy scenario, project costs would need to increase by 35 percent. To negate the $202 million in risk-adjusted, post-IRA benefits under the MN price-policy scenario, project costs would need to increase by 22 percent.

Q. Are the Company's economic analyses of the expected customer benefits from Rock Creek I conservative?

A. Yes. The PVRR(d) results for Rock Creek I does not reflect the potential value of RECs generated by the incremental energy output from the renewable project. Customer benefits for all price-policy scenarios would improve by approximately $14 million for every dollar assigned to the incremental RECs that will be generated through 2040.

Similarly, the Company's analyses understate forecast coal costs for certain system resources, including the Dave Johnston plant. If corrected to include the full costs of fuel supply for all plants, the Company's economic analysis would demonstrate even higher benefits for Rock Creek I. Additionally, the natural gas and electricity prices in the Company's September 2022 OFPC are higher than the values assumed in the June 2022 OFPC used in the Company's analysis, which would similarly result in higher benefits for Rock Creek I.

IV. FOOTE CREEK II-IV AND ROCK RIVER I

Q. Please describe the acquisition and repowering of the Foote Creek II-IV and Rock River I wind facilities.

A. As described in the confidential testimony of Company witness Timothy J. Hemstreet, PacifiCorp is acquiring and repowering the 43 MW Foote Creek II-IV and 50 MW Rock River I wind facilities. This involves installing approximately 11 modern wind turbine generators ("WTGs") at the Foote Creek facilities, and 19 wind turbine generators at the Rock River I facility. These new turbines will increase the power generation from the previous capability, and extend the service life of the facility, and allow customers to benefit from this favorable wind site. My testimony provides the economic justification for the Company's decision to acquire and repower these facilities.

A. Resource Need

Q. Did PacifiCorp's preferred portfolio of resources developed in the Company's 2021 IRP include Foote Creek II-IV and Rock River I?

A. Yes.[12]

[12] 2021 IRP, Ch. 1 Action Plan, Action Item 2b, at 25.

Q. Please describe the key factors for including Foote Creek II-IV and Rock River I in the 2021 IRP preferred portfolio.

A. The projects are anticipated to be fully online and serving customers before 2025. This timing enables both projects to deliver needed energy and capacity for customers before the availability of either new proxy resources, or final shortlist project generation expected to be enabled by the Gateway South transmission line, as identified in the Company's 2020AS RFP. Without these projects, the risk of shortfalls is increased as is the Company's reliance on energy markets. In their current states, the existing Rock River I facility is not operating as turbines have been removed pending the repowering of the sites. Repowering will allow the facility to once again provide energy and capacity to serve load and reduce market reliance, while allowing the newly installed turbines to qualify for substantial federal PTCs.

Q. Were each of these facilities included in the Company's 2021 IRP Update?

A. Yes.[13]

[13] PacifiCorp 2021 IRP Update (Mar. 31, 2022).

B. Assumptions and Results

Q. Has the Company performed updated analyses of the projects after filing the 2021 IRP?

A. Yes. The Company performed a 30-year analysis of each project's economics through end-of-life using its PLEXOS modeling system, the same modeling system used for the 2021 IRP.

Q. Please summarize the natural gas and CO_2 price assumptions used in the economic analyses for each project.

A. The economic analysis for each of the projects included four price-policy scenarios—representing low, medium, and high natural gas prices, and zero, medium, high, and the SCGHG CO_2 prices. The price-policy scenario that pairs medium natural gas prices with medium CO_2 prices is referred to as the "MM" scenario, the price-policy scenario that pairs low natural gas prices with a zero CO_2 price is referred to as the "LN" scenario, the price-policy scenario that pairs high natural gas prices with a high CO_2 price is referred to as the "HH" scenario, and the scenario that pairs medium natural gas prices with the SCGHG is referred to as the MM-SCGHG scenario. While the MM price-policy scenario represents the Company's "expected case" describing likely future conditions, the LN, HH, and MM-SCGHG scenarios provide informative analytical bookends scenarios.

Similar to the Company's other analyses, these assumptions can influence 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, non-NPC variable-cost benefits, and system fixed-cost benefits associated with Foote Creek II-IV and Rock River I. Because wholesale power prices and CO_2 policy outcomes are both uncertain and important drivers to the economic analysis, it is important to evaluate a range of assumptions for these variables. The natural gas and CO_2 price assumptions are summarized in Table 5.

Table 5. Price-Policy Assumptions

Price-Policy Scenario	Henry Hub Natural Gas Price (Levelized $/MMBtu)*	CO_2 Price Description
HH	$5.64	22.57/ton starting 2025 rising to 102.48/ton in 2040
MM	$4.44	$9.93/ton starting in 2025 rising to $57.94/ton in 2040
LN	$2.94	None
MM-SCGHG	$4.44	$74.10/ton starting 2021 rising to $150.38/ton in 2040
*Nominal levelized Henry Hub natural gas price from 2025 through 2040.		

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

A. The medium natural gas price assumptions are from PacifiCorp's OFPC dated March 31, 2021, which was the most recent OFPC available when the modeling inputs were developed. The first 36 months of the OFPC reflect market forwards at the close of a given trading day, May 2021 is the prompt month in this case. As such, these 36 months are market forwards as of May 2021. The blending period (months 37 through 48) is calculated by averaging the month-on-month market forwards from the prior year with the month-on-month fundamentals-based price from the subsequent year. The fundamentals portion of the natural gas OFPC reflects Aurora-forecast prices.

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

A. PacifiCorp used four different CO_2 price scenarios—zero, medium, high, and the SCGHG. The medium scenario is derived from a survey of third-party industry experts, including I CERA, and Wood Mackenzie and the Energy Information Administration as well as CO_2 price assumptions used by peer utilities. Both the medium and high scenarios apply a CO_2 price as a tax beginning 2025. PacifiCorp also incorporated the SCGHG that is assumed to start in 2021 for Washington, and is applied such that the SCGHG is reflected in market prices and dispatch costs for the purposes of developing each portfolio (i.e., incorporated into capacity expansion optimization modeling).

Q. How did PacifiCorp pair the natural gas and CO_2 price assumptions for purposes of analyzing Foote Creek II-IV and Rock River I?

A. Scenarios pairing medium gas prices with alternative CO_2 price assumptions reflect OFPC forwards through April 2024 before transitioning to a fundamentals forecast. Scenarios using high or low gas prices, regardless of CO_2 price assumptions, do not incorporate any market forwards because these scenarios are designed to reflect an alternative view to that of the market. As such, the low and high natural gas price scenarios are purely fundamental forecasts. Low and high natural gas price scenarios are also derived from expert third-party, multi-client, "off-the-shelf" subscription services.

Q. Please explain how you conducted your analyses.

A. The methodologies are consistent with the approach used to perform the economic analysis of portfolios in the 2021 IRP. The system value of incremental wind energy from Foote Creek II-IV and Rock River I are each calculated from two PLEXOS ST model simulations for a given price-policy scenario—one simulation with incremental wind energy and one simulation without incremental wind energy. The system value of incremental wind energy is then converted to a dollar-per-$/MWh value by dividing the change in annual system cost by the change in incremental wind energy for both price-policy scenarios through 2040. The value of wind energy is extended out through 2050 by extrapolating the system values calculated from modeled data over the 2038-2040 timeframe. The assumed system value, expressed in dollars per$/MWh, is applied to the incremental energy output associated with each of the wind repowering projects.

Q. Were your initial economic analyses conducted before passage of the IRA?

A. Yes.

Q. How does the IRA impact your analyses?

A. Based on existing law, PacifiCorp's initial economic analyses assumed that both Foote Creek II-IV and Rock River I qualified for 60 percent of available PTCs. After passage of the IRA, the Company understands that each facility now qualifies for 110 percent of available PTCs. The Company has updated its economic analyses to reflect the new PTC value for both projects, and the results are reflected in Tables 6 and 7 below.

Q. What are the results of your economic analyses for Foote Creek II-IV?

A. Table 6 summarizes the PVRR(d) customer benefits (or costs) of Foote Creek II-IV both before and after passage of the IRA.[14] This table also presents the same information on a levelized dollar-per-MWh basis.

Table 6. Foote Creek II-IV (Benefits)/Costs

Price-Policy Scenario	**Pre-IRA PVRR(d) ($ million)**	**Pre-IRA Net Benefit ($/MWh)**	**Post-IRA PVRR(d) ($ million)**	**Post-IRA Net Benefit ($/MWh)**
HH	($80.80)	($38/MWh)	($104.23)	($49/MWh)
MM	($53.07)	($25/MWh)	($76.49)	($36/MWh)
LN	$17.09	$8/MWh	($6.33)	($3/MWh)
MM-SCGHG	($142.77)	($67/MWh)	($166.19)	($78/MWh)

Prior to passage of the IRA, Foote Creek II-IV was expected to deliver $53.07 million in present-value net customer benefits in the MM scenario, and $80.8 million in the HH scenario. This is contrasted with $17.09 million cost in the LN scenario. Under the MM and HH scenarios, nominal levelized net benefits are $25/MWh and $38/MWh, respectively. Under the LN scenario there is a nominal levelized net cost of $8/MWh.

After passage of the IRA, customer benefits increased substantially: Foote Creek II-IV will now deliver $76.49 million in present-value net customer

[14] *See also* Confidential Exhibit No. 34.

benefits in the MM scenario and $104.23 million in the HH scenario.

Importantly, the only scenario where Foote Creek II-IV was expected to generate customer costs prior to passage of the IRA—the LN scenario ($17.09 million)—has transformed to a $6.33 million customer benefit. These benefits only increase under the highest cost of carbon scenario (MM-SCGHG). While the Company decided to move forward with Foote Creek II-IV prior to passage of the IRA, the substantial post-IRA benefits continue to support the Company's decision to acquire and repower the facilities.

Q. What are the results of your economic analyses for Rock River I?

A. Table 7 summarizes the PVRR(d) customer benefits (or costs) of Rock River I both before and after passage of the IRA.[15] This table also presents the same information on a levelized dollar-per-MWh basis.

Table 7. Rock River I (Benefits)/Costs

Price-Policy Scenario	Pre-IRA PVRR(d) ($ million)	Pre-IRA Net Benefit ($/MWh)	Post-IRA PVRR(d) ($ million)	Post-IRA Net Benefit ($/MWh)
HH	($67.76)	($31/MWh)	($91.69)	($43/MWh)
MM	($30.15)	($14/MWh)	($54.09)	($25/MWh)
LN	$23.12	$11/MWh	($15.12)	($7/MWh)
MM-SCGHG	($143.42)	($67/MWh)	($167.35)	($78/MWh)

[15] *See also* Confidential Exhibit No. 35.

Before passage of the IRA, Rock River I was expected to deliver $30.15 million in present-value net customer benefits in the MM scenario, $67.76 million in the HH scenario, and $143.42 million in the MM-SCGHG scenario. This is contrasted with $23.12 million cost in the LN scenario. Under the MM-SCGHG, MM and HH scenarios, nominal levelized net benefits are $67/MWh, $14/MWh and $31/MWh, respectively. Under the LN scenario there is a nominal levelized net cost of $11/MWh.

After passage of the IRA, customer benefits increased substantially: Rock River I will now deliver $54.09 million in present-value net customer benefits in the MM scenario and $91.69 million in the HH scenario. Importantly, the only scenario where Rock River I was expected to generate customer costs before passage of the IRA—the LN scenario ($23.12 million)—has transformed to a $15.12 million customer benefit. These benefits only increase under higher gas or CO_2 scenarios.

Q. Are the Company's economic analyses of the expected customer benefits from Foote Creek II-IV and Rock River I conservative?

A. Yes. The PVRR(d) results do not reflect the potential value of RECs generated by the incremental energy output from each of the wind facilities. Customer benefits for all price-policy scenarios would improve significantly for every dollar assigned to the incremental RECs that will be generated through 2040, and these RECs can also be sold to reduce the revenue requirement impact of this resource.

V. CONCLUSION

Q. Please summarize the conclusions of your testimony.

A. PacifiCorp's economic analysis shows that the Company's decision to procure these resources are necessary, and each will provide substantial customer benefits compared to anticipated project costs.

Q. What is your recommendation?

A. I recommend that the Commission determine that the Company's decisions to acquire Rock Creek I, and acquire and repower Foote Creek II-IV and Rock River I were prudent.

Q. Does this conclude your direct testimony?

A. Yes.

REDACTED
Case No. PAC-E-24-04
Exhibit No. 32
Witness: Thomas R. Burns

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

REDACTED
Exhibit Accompanying Direct Testimony of Thomas R. Burns

Rock Creek I and II Pre-IRA Combined Analysis

May 2024

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Exhibit No. 33
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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

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Exhibit Accompanying Direct Testimony of Thomas R. Burns

Rock Creek I and II Post-IRA Combined Analysis

May 2024

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ROCKY MOUNTAIN POWER

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Foote Creek II-IV Analysis

May 2024

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Rock River Analysis

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