Confidential per WAC 480-07-160
Exh. TRB-1CTr
Docket UE-23~~____~~0172
Witness: Thomas R. Burns

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PACIFICORP dba PACIFIC POWER & LIGHT COMPANY Respondent.	Docket UE-23~~____~~0172

PACIFICORP

REDACTED DIRECT TESTIMONY OF THOMAS R. BURNS

~~March 2023~~REVISED April 4, 2023

TABLE OF CONTENTS

EXHIBITS

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 its coal units and derive 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. Has the Company prepared an update to the 2021 IRP?

A. Yes. On March 31, 2022, the Company issued its 2021 IRP Update.[1]

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

of solar resources and 497 MW of battery storage resources. This under-procurement adds to our need for new resources.

Q. How does the Company's 2021 IRP relate to the 2021 CEIP?

A. The CEIP represents a Washington-specific plan to meet the needs of the Company's Washington customers. This includes developing interim and specific targets to meet the ambitious goals of Washington's CETA, among others, creating customer benefit indicators, detailing specific actions, estimating incremental costs for these actions, and providing for robust public participation.[2] The economic analysis supporting the CEIP is derived from the Company's IRP analyses.

Q. Do the Company's IRP and IRP Updates analyze the cost-effectiveness of continued operation of its coal fleet?

A. Yes. These documents examine PacifiCorp's existing coal plants as part of determining the least-cost, least-risk portfolio of resources to serve customers. This examination includes analyzing the early retirement and conversion to natural gas of coal plants while appropriately considering the potential avoidance of incremental environmental compliance costs, which represents a potentially significant benefit in early closure scenarios.

Q. Were the retirement dates of any coal units driven by environmental requirements in the 2021 IRP?

A. Yes, the retirement dates for Craig Unit 2, Hayden Units 1 and 2, and Naughton Units 1 and 2 are driven by environmental requirements.

[2] PacifiCorp's 2021 CEIP (Dec. 30, 2021) (https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/ceip/PAC-CEIP-12-30-21_with_Appx.pdf).

Q. Did PacifiCorp's preferred portfolio of resources in the Company's 2021 IRP include the Jim Bridger conversion?

A. Yes. In the 2021 IRP, the Company evaluated a number of scenarios specific to the valuation of Jim Bridger Units 1 and 2 that excluded and included the conversion of these units to natural gas fueled operation. The Company concluded that the portfolio that eliminated gas conversion of Jim Bridger Units 1 and 2 was significantly higher cost than the portfolio that included its inclusion across each of the price-policy scenarios,[3] and included the resources as part of the least-cost, least-risk 2021 IRP preferred portfolio.[4]

Q. Please describe key factors for including the Jim Bridger conversion in the 2021 IRP preferred portfolio.

A. The Company evaluated several alternatives, including the addition of new renewable generation resources, alternative coal unit retirement timing, regional haze compliance operating limits, and gas conversions or installation of carbon capture, utilization and storage. On a risk-adjusted basis, the portfolio without natural gas conversion of Jim Bridger Units 1 and 2 results in approximately $469 million higher costs than the preferred portfolio.

Q. Was the Jim Bridger conversion included in the 2021 IRP Update?

A. Yes. The conversion of Jim Bridger Units 1 and 2 were included in the preferred portfolio identified in the 2021 IRP Update.[5] This is consistent with the substantial

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[3] PacifiCorp 2021 IRP, Vol. 1, at 270 (Sept. 1, 2021) (https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021-irp/Volume%20I%20-%209.15.2021%20Final.pdf).

[4] *Id.* at Ch. 1 Action Plan, Action Item 1c, at 24.

[5] PacifiCorp 2021 IRP Update, Ch. 7 Action Plan Status update, Action Item 1c, at 98 (https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021_IRP_Update.pdf).

and increased need for additional generation resources first identified in the 2021 IRP, and then confirmed in the 2021 IRP Update.

Q. Was the Jim Bridger conversion addressed in the 2021 draft and final CEIPs?

A. Yes. The Company's draft CEIP noted that economic analysis supported converting Jim Bridger units to natural gas, including a statement that the Company did not anticipate allocating any of the converted Jim Bridger units to Washington.[6] However, the Company received public comments from various stakeholders, including the Alliance of Western Energy Consumers and Washington Utilities & Transportation Commission (Commission) Staff, questioning this assumption.[7] In response to this feedback, the Company's final CEIP removed the statement.[8]

B. Modeling Assumptions

Q. Please summarize the natural gas and CO2 price assumptions used in the economic analysis for Jim Bridger.

A. The economic analysis of Jim Bridger included five different price policy-scenarios—medium natural gas prices paired with medium CO_2 prices (MM); low natural gas prices without a CO_2 price (LN); medium natural gas prices without a CO_2 price (MN); high natural gas prices paired with high CO_2 prices (HH); and under medium gas prices and the social cost of greenhouse gases (SCGHG). While the MM price-policy scenario represents the Company's "expected case" describing likely future conditions, the additional scenarios provide additional helpful analyses.

[6] *In re* PacifiCorp's CEIP, Docket No. 210829, Draft CEIP, at 16 (Nov. 01, 2021) (https://apiproxy.utc.wa.gov/cases/GetDocument?docID=4&year=2021&docketNumber=210829).
[7] PacifiCorp 2021 CEIP, Stakeholder Input and Responses, comments 241, 329.
[8] *Compare* PacifiCorp Draft CEIP, at 16, *with* PacifiCorp's Final CEIP, at 19.

Units 1 and 2 on a dollar-per-megawatt-hour (MWh) basis. These price-policy scenarios are discussed below.

C. Price-Policy Scenario Results

Q. Please summarize the PVRR(d) and levelized results for Jim Bridger Units 1 and 2.

A. Table 2 summarizes the PVRR(d) between cases, with and without Jim Bridger Units 1 and 2.[9]

Table 2. Jim Bridger Units 1 and 2 (Benefits)/Costs

Price-Policy Scenario	PVRR(d) ($ million)	Net Benefit ($/MWh)
HH	($515.20)	($321.79)
MN	($595.67)	($609.59)
MM	($656.41)	($174.87)
LN	($378.79)	($237.21)
MM-SCGHG	($271.68)	($17.57)

Converting Jim Bridger Units 1 and 2 to operate on natural gas is expected to deliver $656.41 million in present-value net customer benefits in the MM scenario, $515.20 million in the HH scenario, and $271.68 million in the MM-SCGHG scenario. Under the MM, HH and MM-SCGHG scenarios, nominal levelized net benefits are $174.87/MWh, $312.79/MWh, and $17.57/MWh, respectively. Company forecasting and the relative magnitude of benefits over costs across these scenarios, as well as near-term resource need and the ability of the project to reduce the Company's reliance, strongly support the conversion of Jim Bridger Units 1 and 2.

IV. ROCK CREEK I AND II

Q. Please describe the acquisition of the Rock Creek Projects.

A. As described in the testimony of Company witness Ryan D. McGraw, Exhibit

[9] Exhibit No. TRB-2 Jim Bridger Analysis

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

A. Acquiring the Rock Creek Projects 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 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, WECC and NERC reliability studies highlight the risks of resource shortfalls across the region in the coming years.

Q. How do these studies relate to the Rock Creek Projects?

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.[11]

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[11] 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).

C. Price-Policy Scenario Results

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.[20]

Table 4. Post-IRA (Benefit)/Cost of Both Wind Projects ($ million)

Price-Policy Scenario	(a) PVRR(d)	(b) Risk-Adjusted PVRR(d)	(c) 110% PTC Update	(d) Project Cost Update	(e) = (c) + (d) Total Update	(f) = (a) + (e) Updated PVRR(d)	(g) = (b) + (e) 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 (g)), 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 the wind projects, and indicates they 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 the modeled OTR allowance requirements compare to PacifiCorp's forecasted allowance allocation?

A. The annual allowance requirements in the ST-model results are generally slightly

[20] Exhibit No. TRB-3 Rock Creek Analysis

IRA. This table also presents the same information on a levelized dollar-per-MWh basis.[24]

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)

Before 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, $80.8 million in the HH scenario, and $142.77 million in the MM-SCGHG scenario. This is contrasted with $17.09 million cost in the LN scenario. Under the MM-SCGHG, MM and HH scenarios, nominal levelized net benefits are $67/MWh, $25/MWh and $38/MWh, respectively. Under the LN scenario there is a nominal levelized net cost of $8/MWh. Company forecasting and the relative magnitude of benefits over costs across these scenarios, as well as near-term resource need and the ability of the project to reduce the Company's reliance on market purchases, all support acquiring and repowering the Foote Creek II-IV project.

After passage of the IRA, customer benefits increased substantially: Foote Creek II-IV will now deliver $76.49 million in present-value net customer 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 before passage of the IRA—the LN scenario ($17.09 million)—has transformed to a

[24] Exhibit No. TRB-4 Foote Creek Analysis

$6.33 million customer benefit. While the Company decided to move forward with Foote Creek II-IV before passage of the IRA, the substantial post-IRA benefits continue to support the Company's decision to acquire and repower the facilities.

Q. Has the Company updated its analysis of Rock River I after filing the 2021 IRP?

A. Yes. The Company updated its economic analysis in 2022 to support the Company's decision to acquire and repower Rock River I, and these results are reflected below.

Q. Please summarize the PVRR(d) and levelized results for Rock River I.

A. Table 7 summarizes the PVRR(d) between cases, with and without Rock River I acquisition and repowering, for customer benefits before and after passage of the IRA. This table also presents the same information on a levelized dollar-per-megawatt-hour basis.[25]

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)	($32/MWh)	($91.69)	($43/MWh)
MM	($30.15)	($14/MWh)	($54.09)	($25/MWh)
LN	$8.82	$4/MWh	($15.12)	($7/MWh)
MM-SCGHG	($143.42)	($67/MWh)	($167.35)	($78/MWh)

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 $8.82 million cost in the LN scenario. Under the MM-SCGHG, MM and HH scenarios, nominal levelized net benefits are $67/MWh, $14/MWh and $32/MWh, respectively. Under the LN scenario there is a nominal levelized net cost of $4/MWh. Company forecasting and the relative magnitude of

[25] Exhibit No. TRB-5 Rock River Analysis

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Exh. TRB-1CTr
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Witness: Thomas R. Burns

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Units 1 and 2 on a dollar-per-megawatt-hour (MWh) basis. These price-policy scenarios are discussed below.

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	(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)
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Before adjusting for risk (Column (g)), 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 the wind projects, and indicates they 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 the modeled OTR allowance requirements compare to PacifiCorp's forecasted allowance allocation?

A. The annual allowance requirements in the ST-model results are generally slightly

[20] Exhibit No. TRB-3 Rock Creek Analysis

IRA. This table also presents the same information on a levelized dollar-per-MWh basis.[24]

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)

Before 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, $80.8 million in the HH scenario, and $142.77 million in the MM-SCGHG scenario. This is contrasted with $17.09 million cost in the LN scenario. Under the MM-SCGHG, MM and HH scenarios, nominal levelized net benefits are $67/MWh, $25/MWh and $38/MWh, respectively. Under the LN scenario there is a nominal levelized net cost of $8/MWh. Company forecasting and the relative magnitude of benefits over costs across these scenarios, as well as near-term resource need and the ability of the project to reduce the Company's reliance on market purchases, all support acquiring and repowering the Foote Creek II-IV project.

After passage of the IRA, customer benefits increased substantially: Foote Creek II-IV will now deliver $76.49 million in present-value net customer 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 before passage of the IRA—the LN scenario ($17.09 million)—has transformed to a

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$6.33 million customer benefit. While the Company decided to move forward with Foote Creek II-IV before passage of the IRA, the substantial post-IRA benefits continue to support the Company's decision to acquire and repower the facilities.

Q. Has the Company updated its analysis of Rock River I after filing the 2021 IRP?

A. Yes. The Company updated its economic analysis in 2022 to support the Company's decision to acquire and repower Rock River I, and these results are reflected below.

Q. Please summarize the PVRR(d) and levelized results for Rock River I.

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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)	($32/MWh)	($91.69)	($43/MWh)
MM	($30.15)	($14/MWh)	($54.09)	($25/MWh)
LN	$8.82	$4/MWh	($15.12)	($7/MWh)
MM-SCGHG	($143.42)	($67/MWh)	($167.35)	($78/MWh)

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 $8.82 million cost in the LN scenario. Under the MM-SCGHG, MM and HH scenarios, nominal levelized net benefits are $67/MWh, $14/MWh and $32/MWh, respectively. Under the LN scenario there is a nominal levelized net cost of $4/MWh. Company forecasting and the relative magnitude of

[25] Exhibit No. TRB-5 Rock River Analysis