PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah Street, Suite 2000
Portland, Oregon 97232

July 24, 2023

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street SE, Suite 100
Salem, OR 97301-3398

Re: UE 420—PacifiCorp's Reply Testimony and Exhibits

PacifiCorp d/b/a Pacific Power encloses for filing in the above-referenced docket the Reply Testimony and Exhibits of Ramon R. Mitchell, James Owen, Zepure Shahumyan, and Matthew D. McVee.

Included with this filing are electronic workpapers, which have been uploaded to Huddle. Confidential and highly confidential material in support of the filing has been provided to parties under Order No. 16-128 and Order No. 23-211.

If you have any questions about this filing, please contact Cathie Allen, Regulatory Affairs Manager, at (503) 813-5934.

Sincerely,

Matthew McVee
Vice President, Regulatory Policy and Operations

Enclosures

CERTIFICATE OF SERVICE

I certify that I delivered a true and correct copy of PacifiCorp's **Reply Testimony and Exhibits** on the parties listed below via electronic mail in compliance with OAR 860-001-0180.

Service List
UE 420

AWEC	
TYLER C PEPPLE **(C)** **(HC)** DAVISON VAN CLEVE, PC 1750 SW HARBOR WAY STE 450 PORTLAND OR 97201 tcp@dvclaw.com	BRENT COLEMAN **(C)** **(HC)** DAVISON VAN CLEVE, PC 1750 SW HARBOR WAY STE 450 PORTLAND OR 97201 blc@dvclaw.com
JESSE O GORSUCH **(C)** **(HC)** DAVISON VAN CLEVE 1750 SW HARBOR WAY STE 450 PORTLAND OR 97201 jog@dvclaw.com	
CALPINE SOLUTIONS	
GREGORY M. ADAMS **(C)** **(HC)** RICHARDSON ADAMS, PLLC 515 N 27th ST BOISE ID 83702 greg@richardsonadams.com	GREG BASS CALPINE ENERGY SOLUTIONS, LLC 401 WEST A ST, STE 500 SAN DIEGO CA 92101 greg.bass@calpinesolutions.com
KEVIN HIGGINS **(C)** ENERGY STRATEGIES LLC 215 STATE ST - STE 200 SALT LAKE CITY UT 84111-2322 khiggins@energystrat.com	
OREGON CITIZENS UTILITY BOARD	
OREGON CITIZENS' UTILITY BOARD 610 SW BROADWAY, STE 400 PORTLAND, OR 97205 dockets@oregoncub.org	MICHAEL GOETZ **(C)** **(HC)** OREGON CITIZENS' UTILITY BOARD 610 SW BROADWAY STE 400 PORTLAND, OR 97205 mike@oregoncub.org
ROBERT JENKS **(C)** **(HC)** OREGON CITIZENS' UTILITY BOARD 610 SW BROADWAY, STE 400 PORTLAND, OR 97205 bob@oregoncub.org	

KWUA	
KWUA KLAMATH WATER USER ASSOCIATION KLAMATH BASIN WATER USER PROTECTIVE ASSOCIATION 2312 SOUTH SIXTH ST, STE A KLAMATH FALLS, OR 97601 assist@kwua.org	PAUL S SIMMONS **(C)** **(HC)** SOMACH SIMMONS & DUNN 500 CAPITOL MALL STE 1000 SACRAMENTO CA 95814 psimmons@somachlaw.com
PACIFICORP	
PACIFICORP, DBA PACIFIC POWER 825 NE MULTNOMAH ST, STE 2000 PORTLAND, OR 97232 oregondockets@pacificorp.com	AJAY KUMAR **(C)** **(HC)** PACIFICORP 825 NE MULTNOMAH ST STE 2000 PORTLAND, OR 97232 ajay.kumar@pacificorp.com
SIERRA CLUB	
LEAH BAHRAMIPOUR **(C)** **(HC)** SIERRA CLUB 2101 WEBSTER STREET SUITE 1300 OAKLAND CA 94612 Leah.bahramipour@sierraclub.org	ROSE MONAHAN **(C)** **(HC)** SIERRA LCU 2101 WEBSTER ST STE 1300 OAKLAND CA 94612 rose.monahan@sierraclub.org
STAFF	
STEPHANIE S ANDRUS **(C)** **(HC)** PUC STAFF - DEPARTMENT OF JUSTICE 1162 COURT ST NE SALEM, OR 97301 stephanie.andrus@doj.state.or.us	
VITESSE LLC	
DENNIS BARTLETT **(C)** META PLATFORMS INC 1 HACKER WAY MENLO PARK CA 94025 dbart@meta.com	LIZ FERRELL **(C)** META PLATFORMS INC 1 HACKER WAY MENLO PARK CA 94025 eferrell@meta.com
IRION SANGER **(C)** **(HC)** SANGER LAW PC 4031 SE HAWTHORNE BLVD PORTLAND OR 97214 irion@sanger-law.com	

Dated this 24th day of July, 2023.

Carrie Meyer

Carrie Meyer
Adviser, Regulatory Operations

REDACTED
Docket No. UE 420
Exhibit PAC/400
Witness: Ramon J. Mitchell

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Reply Testimony of Ramon J. Mitchell

July 2023

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ATTACHED EXHIBITS

I. INTRODUCTION

Q. Are you the same Ramon J. Mitchell who previously submitted direct testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company)?

A. Yes.

II. PURPOSE OF TESTIMONY

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

A. My testimony has two sections. First, I provide a Transition Adjustment Mechanism (TAM) update (Reply Update), as allowed under TAM Guidelines adopted by the Public Utility Commission of Oregon (Commission) in Order No. 09-274 and revised in Order Nos. 09-432 and 10-363.[1] In the Reply Update, I explain the reasonableness of the Company's updated Oregon net power costs (NPC) of $2.528 billion (total-company) for the test period of the 12 months ending December 31, 2024.[2] This results in a rate decrease of $32.8 million, Oregon-allocated, compared to the 2024 TAM initial filing (Initial Filing), for a total TAM increase of $130.8 million, Oregon-allocated. I provide corrections and contract, fuel, forward price curve and environmental compliance updates to the Company's Initial Filing.

Second, I respond to the opening testimony of Anna Kim, Julie Jent, Curtis Dlouhy, Rose Anderson, Madison Bolton, and Itayi Chipanera, filed on behalf of Staff, Bob Jenks, filed on behalf of the Oregon Citizens' Utility Board (CUB),

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[1] *In the Matter of PacifiCorp, dba Pacific Power 2009 Transition Adjustment Mechanism*, Docket No. UE 199, Order No. 09-274, App'x A (Jul. 16, 2009); *In the Matter of PacifiCorp's 2010 Transition Adjustment Mechanism*, Docket No. UE 207, Order No. 09-432, at 4 (Oct. 30, 2009); *In the Matter of PacifiCorp's 2011 Transition Adjustment Mechanism*, Docket No. UE 216, Order No. 10-363, at 3-4 (Sept. 16, 2010).

[2] Unless otherwise specified, references to NPC throughout my testimony are expressed on a total-company basis.

Bradley G. Mullins, on behalf of the Alliance of Western Energy Consumers (AWEC), Ed Burgess and Maria Roumpani, filed on behalf of the Sierra Club, Steve Johnson, filed on behalf of Vitesse, LLC (Vitesse), and Kevin C. Higgins, on behalf of Calpine Energy Solutions, LLC (Calpine).

Q. Please summarize your testimony.

A. I demonstrate the reasonableness of PacifiCorp's NPC in the 2024 TAM through the following points:

- The Company continues to persistently and significantly under-forecast the costs to serve Oregon customers as a result of under-forecasting NPC in the TAM. Without any consideration of this history, Staff and intervenors continue to push for adjustments designed to further drive down the NPC forecast, which will only exacerbate the persistent under-forecasting and inaccuracy of the NPC forecast. I discuss this in Section IV.
- The Company's proposed modeling refinement to the Day-Ahead and Real-Time (DA/RT) adjustment's price component improves the accuracy of the TAM forecast. The Company's refinement to the DA/RT price component relies on a percentage, rather than a fixed amount, to adjust the hourly prices for purchases and sales. Using a percentage more accurately reflects price variability throughout the day and is more consistent with historical data than the use of a constant dollar adjustment in all hours. Furthermore, there are no artificial losses in the DA/RT adjustment. By design, losses in the *price* component are offset by gains in the *volume* component. I discuss this in Section V.
- The Commission should approve decreased market capacity limits (market caps)

based on the "average of averages" methodology. Using the third quartile of averages methodology over-forecasts off-system sales volumes, which creates modeled revenues that decrease NPC but that are not achievable in actual operations. By reducing market caps, the Company will forecast off-system sales volumes that are more consistent with historical and expected market opportunities. Reducing market caps is particularly critical now because there is an unmistakable trend toward lower off-system sales volumes, and it is extremely unlikely that the Company could ever achieve the level of off-system sales volumes allowed by the use of the third quartile of averages market cap methodology. I discuss this in Section VI.

- The Company's modeling of the Ozone Transport Rule (OTR) reasonably reflects the final version of the rule, which was published after the Company's Initial Filing. The Company's updated modeling largely resolves issues raised by the parties. I discuss this in Section VII.
- The Company's modeling of coal unit dispatch accurately reflects both the actual and expected contractual requirements of the Company's coal supply agreements and accurately reflects the current market conditions resulting from operational changes to the Company's generation fleet and coal market constraints in Utah. I discuss this in Section VIII.
- The TAM forecast must reflect the actual costs to generate at the Company's Chehalis gas-fired generating plant, including the costs of the Washington Cap and Invest Program. Ignoring these real costs will result in Oregon customers receiving the benefits of Chehalis without paying the costs and will create an

inaccurate forecast relative to actual operations. In addition, the Company is required to comply with Washington law, including the requirements applicable to no-cost emission allowances provided by Washington for the benefit of Washington customers. I discuss this in Section IX.

- The Company's wind generation forecast is reasonable and consistent with Staff's general framework, as corrected to reflect the impact of repowering. I discuss this in Section X.
- The optimized modeling of the gas-converted Jim Bridger units' dispatch is reasonable and reflects both the expected heat rates and emissions levels. I discuss this in Section XI.
- The methodology for forecasting Qualifying Facility (QF) generation produces reasonably accurate results and should continue unchanged. To the extent the Commission is inclined to adopt dollar-for-dollar recovery for QF costs, there is no reason to limit dollar-for-dollar recovery to only QF costs. I discuss this in Section XIV.
- The Company's modeling of the Western Energy Imbalance Market (EIM) is reasonable subject to the modification proposed by Vitesse. I discuss this in Section XVI.
- The Commission should defer any discussion of the Company's participation in and operational approach to the Extended Day Ahead Market (EDAM), which will not be in effect during the 2024 test period of this TAM. I discuss this in Section XVII.
- The Company complies with the TAM Guidelines in both its treatment of the

adjustments that were approved for use in the 2023 TAM on a non-precedential basis and its step log. To address parties' concerns, however, the Company has included a more detailed breakdown of adjustments implemented in this case. I discuss this in Section XIX.

- CUB's recommendation for another NPC update in October is unnecessary, unreasonable, and infeasible given the amount of preparation required in September and October to provide the TAM November filings. Additionally, CUB's recommendation is of limited value. I discuss this in Section XX.
- The transition adjustments and consumer opt-out charge calculations as proposed by the Company in its Initial Filing accurately incorporates the DA/RT adjustment and appropriately values energy impacts resulting from departing direct access load using the same forward prices that are used to set the TAM NPC forecast. I discuss this in Section XXI.

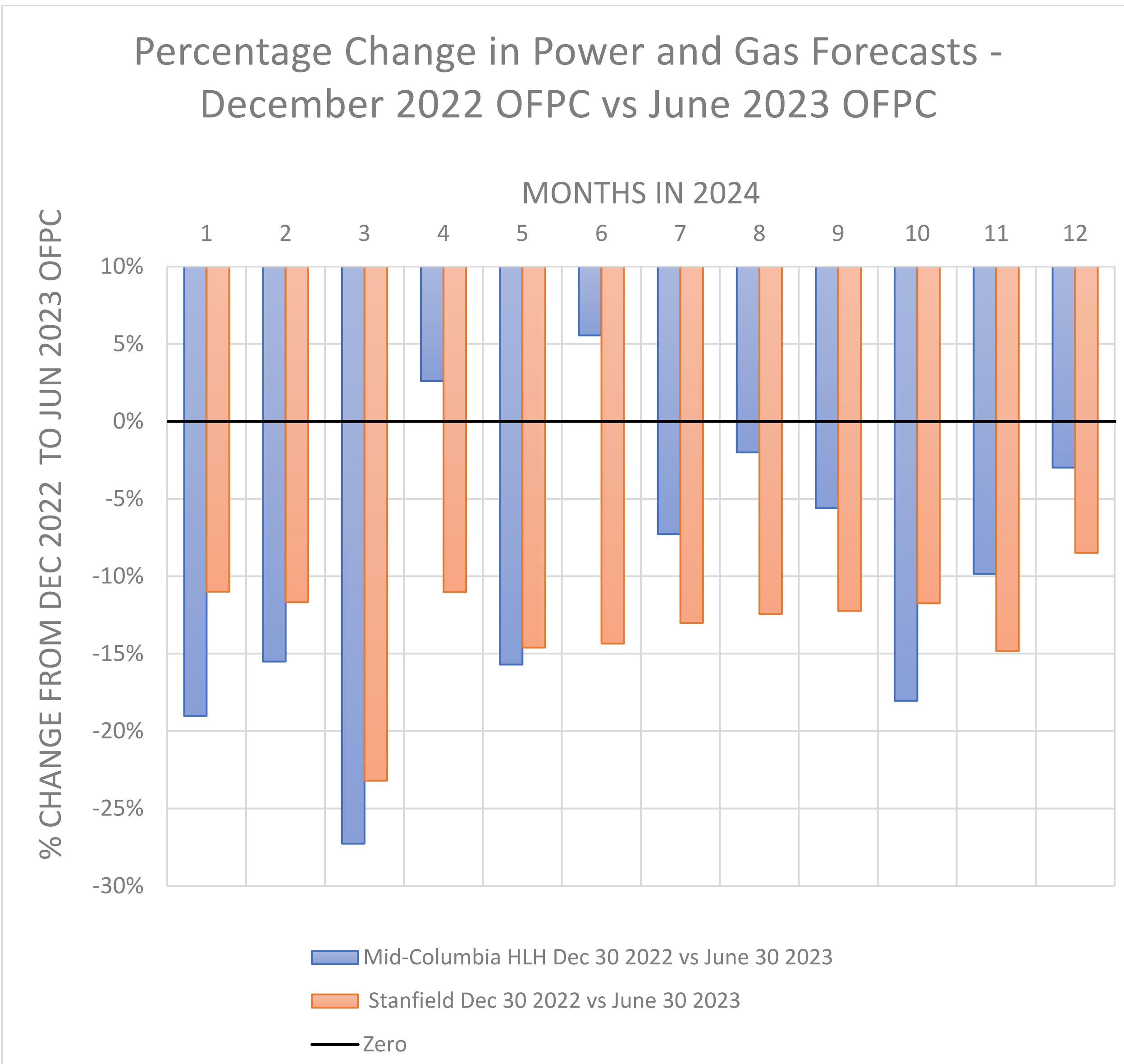
III. TAM REPLY UPDATE

Q. How has the Company's NPC recommendation changed from the Initial Filing?

A. Total-company NPC decreased by $115 million compared to the forecast included with the Initial Filing, from $2.642 billion (total-company) to $2.528 billion (total-company). This change is primarily driven by: (1) updated assumptions on the OTR based on the finalization and publication of the rule in the Federal Register; (2) decreases in the official forward price curve (OFPC) for power and gas; and (3) a modeling logic refinement to increase the flexibility and reduce the in-model costs of coal and gas generation. Details on the changes in the OTR assumptions and an outline of the OTR itself is presented below and in the testimony of Company witness

James Owen. OFPC decreases since the Initial Filing are illustrated below in Figure 1. Exhibit PAC/401 tabulates the modeling sensitivities that show, in finer granularity, the change in NPC from the Initial Filing to this Reply Update. Exhibit PAC/402 shows that PacifiCorp's Reply Update proposes a rate increase of $130.8 million, Oregon-allocated. Details of total-company NPC for this Reply Update are provided in Exhibit PAC/403.

Figure 1



Q. Please explain the changes reflected in your revised NPC request.

A. First, consistent with the TAM Guidelines the Company made routine updates to the Initial Filing and updated the Company's proposed NPC with (1) the most recent OFPC and short-term firm transactions, (2) new power, fuel, and transportation/transmission contracts and updates to existing contracts, and (3) EIM benefits based on recent actual EIM benefit information as well as the updated OFPC. Finally, corrections to thermal unit startup costs, wind capacity factors, contingency reserves for non-owned generation, and an update to the DA/RT volume component have been included in this update.

Additionally, the Company proposes to accept two changes to the NPC forecast in response to the parties' opening testimony. The first regards the EIM greenhouse gas (GHG) benefit forecast. Vitesse's testimony included a proposal to update the methodology to account for growth rates in the California Air Resources Board GHG allowance prices.[3] The second is a proposal in Vitesse's testimony to update the calculation of the DA/RT percentile adders from a simple weighted average to a volume weighted average.[4] My testimony addresses these topics below.

Q. Please summarize the major changes in NPC resulting from the Reply Update.

A. Table 1 below has details regarding the individual cost categories that accumulate to the change in the total NPC forecast (total-company).

[3] Vitesse 100, Johnson/19.
[4] Vitesse 100, Johnson/11.

Table 1

Net Power Cost Reconciliation (Dollars)		
	($ millions)	**$/MWh**
OR 2024 TAM Initial	**2,642**	**39.65**
Increase/(Decrease) to NPC:		
Wholesale Sales Revenue	10.3	
Purchased Power Expense	(52.7)	
Coal Fuel Expense	(9.0)	
Natural Gas Fuel Expense	(66.6)	
Wheeling and Other Expense	3.4	
Total Change to NPC	**(114.6)**	
OR 2024 TAM Reply	**2,528**	**37.93**

Q. Please explain in further detail how the update to OTR assumptions and coal unit flexibility have impacted NPC.

A. As explained in more detail below in my testimony, the Company has updated its OTR modeling to use state-level Company budgets of nitrogen oxide (NOx) allowances, shared by all Company thermal generating units within that state. Inter-state NOx allowance transfers are also permissible within pre-defined Environmental Protection Agency (EPA) limits. As a result, and in combination with a modeling logic refinement to increase the flexibility of coal generation and decrease the associated in-model costs, the net thermal generation in megawatt-hours (MWh) has increased by approximately 1,676,600 MWh total-company. Simultaneously, the corresponding net thermal generation expense has decreased by $75.7 million total-company, primarily driven by reductions in gas market prices since the last OFPC.

Q. Please explain in further detail how the OFPC changes in power prices and gas prices have impacted NPC.

A. On average, power market prices have decreased by approximately 10 percent and gas market prices have decreased by approximately 12 percent. This change has decreased purchased power expense. Furthermore, despite power market prices decreasing, the increase in thermal generation resulting from the OTR modeling changes, and modeling logic refinement in coal generation flexibility have increased both wholesale sales volume and associated wholesale sales revenue. However, as discussed in detail below in Section V(C) of my testimony, a correction to the DA/RT adjustment's *volume* component has removed artificial arbitrage revenue ("artificial gains") from the NPC forecast and this isolated change dampens the decrease in the net of purchased power expense and wholesale sales revenue.

Table 2

Net Power Cost Reconciliation (Energy)		
	GWh	**$/MWh**
OR 2023 TAM Initial	**66,640**	**39.65**
Change to System Load:		
Wholesale Sales Increase	(758.2)	
Purchased Power Decrease	(945.2)	
Coal Generation Increase	1,320.9	
Natural Gas Generation Increase	355.7	
Other Generation Increase	26.8	
Total Change to System Load	**(0)**	
OR 2024 TAM Reply	**66,640**	**37.93**

Q. Please explain the updates included in the Company's Reply Update.

A. The Reply Update includes the following corrections and updates (the NPC impacts are based on this Reply Update, and are one-off sensitivities):

- **Startup Costs –** The Company corrected a formulaic error in the calculation of startup costs. In the Initial Filing some costs were calculated based on a generating unit's minimum capacity; however, Aurora requires the numbers be input based on a generating unit's maximum capacity. In addition, some maintenance costs-per-start were omitted from coal units. Although coal maintenance costs-per-start are not part of the TAM NPC, they are variable power costs that need to be accounted for in-model. The impact is a decrease in total-company NPC of $8.0 million.
- **Wind Capacity Factors –** The Company corrected an error in the annual wind shape inputs of certain wind facilities. For wind facilities that have forecasts based on historical data, there was an average deviation of 0.00042 percent in the input capacity factors from the historical data. For some wind facilities that do not have sufficient historical data, the efficiency increases in the repowered turbines were used to determine the input wind generation profiles instead of the capacity factors settled on in the 2020 TAM and more recently in the 2024 Renewable Adjustment Clause (RAC). The impact is a decrease in total-company NPC of $1.9 million.
- **Contingency Reserves for Non-Owned Generation –** The Company corrected a formulaic error in the calculation of MWh generated in the Company's PacifiCorp East and PacifiCorp West balancing authority areas by third-party (non-owned) generation which determines the Company's North American Electric Reliability Corporation (NERC) mandated contingency reserve requirements (BAL-002-

WECC-3, spinning and non-spinning reserves). The impact is an increase in total-company NPC of $51 million.

- **DA/RT Volume Component –** The Company corrected an error in the DA/RT adjustment by removing unsupported artificial arbitrage revenue ("artificial gains") from the DA/RT volume component. The arbitrage revenue present in the Initial Filing was above the levels supported by the historical data and showed a substantial and illogical *decrease* to power costs resulting from *inefficiencies* in actual power trading, as compared to the actual increase in power costs that result from inefficiencies in actual power trading. The impact is an increase in total-company NPC of $61 million and discussed below in Section V(C) of my testimony.
- **OTR NOx Allowance Aggregation –** The Company updated its modeling for the OTR to allow for state-level Company budgets of NOx allowances to be shared by all Company thermal generating units within that state, as compared to the unit level NOx limits used in the Initial Filing. Furthermore, NOx allowances may be transferred between Utah and Wyoming so long as an individual state does not exceed 121 percent of its aggregate NOx budget and so long as the Company's total budget is not exceeded.

  This update is based on the OTR as finalized and published in the Federal Register on June 5, 2023. Furthermore, the Company assumes that there will be negligible trading in NOx allowances between entities in calendar year 2024 because, among other reasons, an entity's future NOx allowance budgets are based on that entity's 2024 thermal generation volumes. This update decreases total-company NPC by approximately $156 million.

- **OTR NOx Allowances –** The Company updated the unit and state aggregate NOx allowances based on the OTR as finalized and published in the Federal Register on June 5, 2023. This update decreases total-company NPC by approximately $17 million.
- **Official Forward Price Curves, Power and Gas –** The Company updated the OFPC from December 31, 2022, to June 30, 2023, and included a new Washington Cap and Invest Program auction price into the program's forecast GHG allowance price. On average, market prices for electricity decreased by approximately 10 percent, market prices for natural gas fuel decreased, on average, by approximately 12 percent and Chehalis' GHG allowance price increased (simple average of all auction-cleared prices to date) by 8.9 percent. This update decreases total-company NPC by $118 million.
- **Thermal Generation Marginal Costs –** The Company updated modeling logic within Aurora's optimization to remove the usage of shadow prices to determine the marginal costs of both coal and gas generation subject to explicit seasonal or annual constraints. This modeling logic refinement allows for increased flexibility in coal and gas generation and primarily results in increased coal generation due to lower in-model costs. This update decreases total-company NPC by $75 million.
- **Coal Supply –** The Company updated coal fuel assumptions to reflect changes in prices and volumes since the Initial Filing. Company witness Owen provides additional detail on this update in his reply testimony. This update decreases

total-company NPC by approximately $1.3 million.

- **Long-Term Contracts and Online Dates –** The Company included long-term contract updates through June 1, 2023, in addition to updating the online dates of Jim Bridger unit 2 ([redacted]) and the dams on the Klamath river ([redacted]). This update increases total-company NPC by approximately $8.6 million.
- **Short-Term Contracts –** New or updated power, gas, transportation, and transmission contracts, physical and financial, were updated through May 31, 2023. These updates increase total-company NPC by approximately $9.6 million.
- **EIM Inter-Regional Transfer Benefits and GHG Benefits –** PacifiCorp's estimated EIM benefits for 2024 have been updated to include the most recent information through May 2023 and updated to the June 2023 OFPC. On a total-company basis, the expected inter-regional transfer benefits are [redacted], a decrease of [redacted]; the total-company forecast GHG benefits are [redacted], a decrease of [redacted]. [redacted] This update increases total-company NPC by approximately [redacted].

Q. Why does the sum of the NPC impacts of the isolated corrections and updates show a greater decrease to NPC than the actual decrease to NPC?

A. The cumulative effect of two or more corrections or updates cancel portions of each other out and this is referred to as the "system balancing impact of adjustments."

Q. Explain in further detail.

A. A simplified example best illustrates this phenomenon. The increased flexibility in the OTR increases the generation of gas plants in the state of Utah. Lowered gas prices also increase the generation of gas plants in the state of Utah. On an isolated basis, if the NPC impact of the increased flexibility in the OTR is calculated, there will be a certain increase to gas generation in the state of Utah when this calculation is done in isolation, without consideration of lowered gas prices. The NPC impacts presented above are exactly this type of isolated impact without consideration of other changes on the Company's system.

On the other hand, if the NPC impact of lowered gas prices is calculated there will also be a certain increase to gas generation in the state of Utah when this calculation is done in isolation, without consideration of the increased flexibility in the OTR. However, if both adjustments are analyzed together (analyzed as one cumulative adjustment) then it is possible that after the increased flexibility in the OTR increases Utah gas generation, the Utah gas generation is high enough such that there may be no more capacity left for the lowered gas prices to bring about additional increases in Utah gas generation.

In this cumulative analysis, the combined effect of the increased flexibility in the OTR and the lowered gas prices may show limited impact to NPC from the lowered gas prices (or vice versa), but on an isolated basis there may be some substantive NPC impact shown for both the increased flexibility in the OTR and simultaneously for the lowered gas prices. The difference between this cumulative analysis and these two isolated analyses is a "system balancing impact of adjustments" and demonstrates a dampened NPC impact in the cumulative analysis as compared to the sum of the isolated analyses.

Q. On June 2, 2023, the Company filed a List of Corrections or Omissions. In this list the Company identified an omission associated with loads in Utah. Why has this omission not been identified in this Reply Update?

A. Upon further examination the Company concluded that there was no omission.

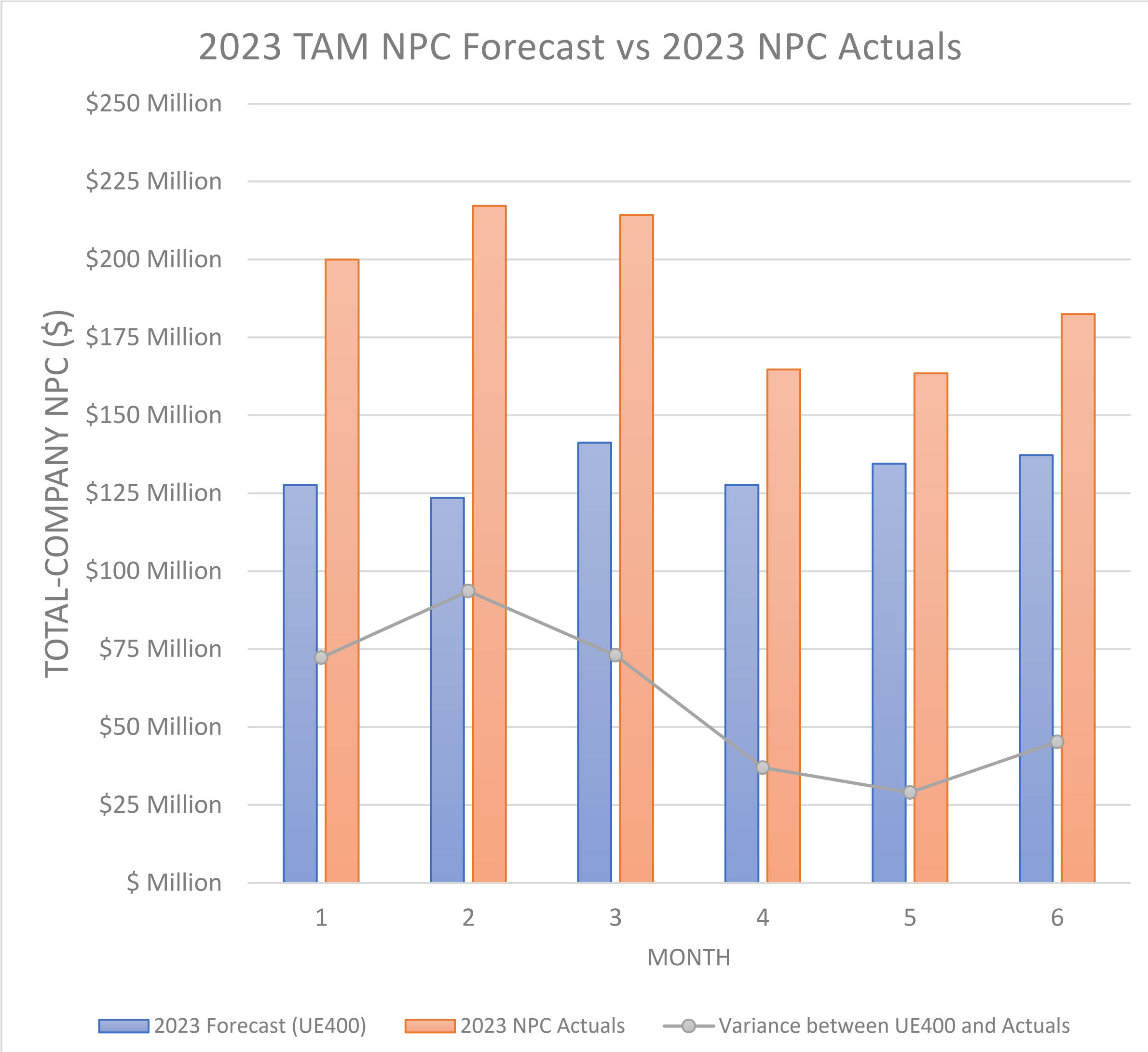
IV. PERSISTENT NPC UNDER-FORECAST

Q. How do the *year-to-date* 2023 NPC actuals compare to last year's final 2023 TAM NPC forecast in docket UE 400?

A. Figure 2 demonstrates the variance between the actual 2023 NPC incurred *year-to-date*, as compared to the forecast of NPC in the 2023 TAM (prior docket) and currently effective in rates. On a preliminary basis, the total *year-to-date*[5] NPC variance is an under-forecast of $350 million dollars total-company.

[5] January 2023 to June 2023.

Figure 2



Q. What is the significance of your emphasis on "year-to-date"?

A. These NPC under-forecast values that sum to $350 million total-company are only for half of a year, from January 2023 to June 2023. Each individual month demonstrates a NPC under-forecast and no single month shows the prior TAM NPC forecast at or above the actual NPC incurred. With information known to date, it is unlikely that the next six months (which include summer) will manage to reverse this TAM NPC under-forecast.

Q. How are these comparisons and associated NPC under-forecast relevant to this year's 2024 TAM NPC forecast?

A. The goal of the TAM is "to achieve an *accurate* forecast of PacifiCorp's power costs for the upcoming year."[6] As we strive to produce an accurate NPC forecast for 2024, it is important to note that the only change in modeling refinements between the prior 2023 TAM and this current 2024 TAM is the elimination of the trapped energy modeling construct. But for this relatively minor change, the modeling refinements that supported the 2023 TAM's NPC forecast are carried over unchanged into this docket.[7]

Despite the persistent and significant NPC under-forecasting in prior TAMs, parties in this case continue to contest certain modeling refinements that they contested in prior TAMs without any consideration for how those modeling refinements help to achieve a more accurate NPC forecast. Indeed, parties' recommendations here nearly uniformly *decrease* the NPC forecast despite the undisputed fact that prior NPC forecasts have been significantly understated.

Q. How would the 2023 TAM NPC forecast have changed had certain contested modeling refinements been removed?

A. If the Company had used a **flat adder** in the DA/RT adjustment's price component and used the **third quartile of averages** market capacity methodology (which are recommendations from the parties in this case), then the 2023 TAM NPC under-forecast would have worsened by $25 million total-company on a *year-to-date* basis,

[6] *In the Matter of PacifiCorp, dba Pacific Power, 2022 Transition Adjustment Mechanism*, Docket No. UE 390, Order No. 21-379, at 3 (Nov. 1, 2021) (emphasis added).
[7] Without consideration of the corrections in this Reply filing, none of which are relevant to the 2023 TAM NPC forecast, but for the DA/RT volume correction.

for a total *year-to-date* under-forecast of approximately $375 million total-company. That is, were it not for the adoption of these modeling refinements the 2023 TAM NPC forecast would be even *less* accurate, which is directly contrary to the Commission's statement that the "accuracy of the [NPC] forecasts is of significant importance to setting fair, just and reasonable rates."[8]

Q. Are the parties still contesting these same modeling refinements aimed at improving the accuracy of the NPC forecast, despite the clear year-to-date under-forecast of calendar year 2023?

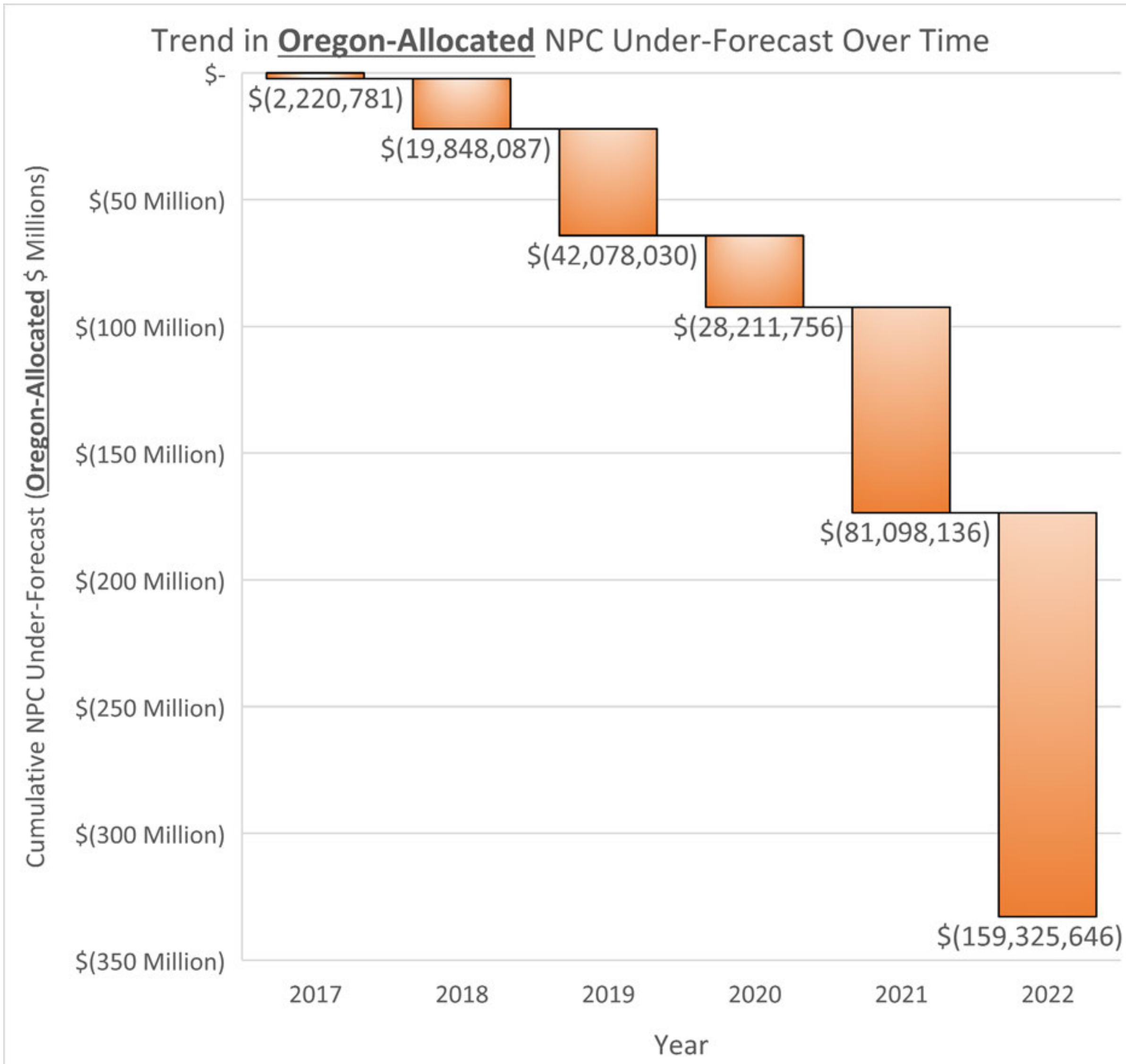
A. Yes.

Q. Have the NPC forecasts in the TAM been persistently under-forecast over the past six years?

A. Yes.[9] Please refer to Figure 3 and Table 3 below.

[8] *In the Matter of PacifiCorp, dba Pacific Power, 2017 Transition Adjustment Mechanism*, Docket No. UE 307, Order No. 16-482, at 2-3 – (Dec. 20, 2016).
[9] *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 399, PAC/1500, Wilding/8 (Jul. 19, 2022).

Figure 3



Note: Beginning in 2017, production tax credits (PTCs) have been included in the TAM and NPC.

Table 3

Year	NPC Collected Through Rates ($) Oregon- Allocated	Actual NPC ($) Oregon-Allocated	Under Forecast of NPC ($) Oregon-Allocated	Under Forecast of NPC (%) Oregon-Allocated
2017	340,640,219	342,861,000	2,220,781	1%
2018	334,683,850	354,531,937	19,848,087	6%
2019	340,850,405	382,928,436	42,078,030	11%
2020	307,368,806	335,580,562	28,211,756	8%
2021	281,150,581	362,248,716	81,098,136	22%
2022	270,869,574	430,195,220	159,325,646	37%

V. DA/RT ADJUSTMENT

Q. Please describe the DA/RT adjustment.

A. PacifiCorp incurs system balancing costs that are not reflected in the Company's OFPC nor modeled in the Company's NPC production cost model. To address this deficiency, in the 2016 TAM, the Company proposed the DA/RT adjustment to more accurately model system balancing transaction prices and volumes.

In the 2016 TAM, Staff, CUB, and the Industrial Customers of Northwest Utilities (ICNU) (the predecessor to AWEC) objected to the DA/RT adjustment. The Commission, however, rejected their arguments and approved the adjustment after concluding that it more accurately reflected the costs of system balancing transactions in the Company's NPC forecast.[10]

In the 2017 TAM, Staff, CUB, and ICNU again objected. The Commission again affirmed the DA/RT adjustment, concluding that it "reasonably addresses a deficiency of the GRID model and is likely to more fully capture PacifiCorp's net variable power costs."[11] The GRID model was the Company's production cost model at that time.

In the 2018 TAM, Staff, CUB, and AWEC again objected to the DA/RT adjustment. The Commission again affirmed the adjustment but adopted a modification to use only post-EIM years.[12]

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[10] *In the Matter of PacifiCorp, dba Pacific Power, 2016 Transition Adjustment Mechanism*, Docket No. UE 296, Order No. 15-394, at 4 (Dec. 11, 2015).
[11] Order No. 16-482, at 13.
[12] *In the Matter of PacifiCorp, dba Pacific Power, 2018 Transition Adjustment Mechanism*, Docket No. UE 323, Order No. 17-444 at 8-9 (Nov. 1, 2017).

The Company then included the DA/RT adjustment in the 2019, 2020, 2021, and 2022 TAMs without modification.

In the 2023 TAM, the Company proposed a refinement to the *price component* of the DA/RT adjustment to change it from a flat value to a percentage of market price, which results in a DA/RT adjustment that is more reflective of actual operations. The 2023 TAM was resolved by a settlement that allowed the Company to implement the refined DA/RT adjustment on a non-precedential basis.[13]

Q. Please explain how the *price component* of the DA/RT adjustment operates.

A. The price component of the DA/RT adjustment addresses the costs incurred by the Company as a result of multiple variables within a dynamic system in which the Company has historically bought more during higher-than-average price periods and sold more during lower-than-average price periods.

To better reflect the market prices available to the Company when it transacts in the real-time market, PacifiCorp includes separate prices for forecast system balancing sales and purchases in Aurora. Aurora is the Company's current production cost model. These prices account for the historical price differences between the Company's purchases and sales compared to the monthly average market-indexed prices. Previously these prices were calculated by adding or subtracting a flat dollar amount to the hourly scaled prices from the OFPC.

[13] *In the Matter of PacifiCorp, dba Pacific Power, Transition Adjustment Mechanism*, Docket No. UE 400, Order No. 22-389, App'x A at 8 (Oct. 25, 2022).

Q. Please describe the *volume component* of the DA/RT adjustment.

A. The Company reflects additional volumes to account for the use of monthly, daily, and hourly products. In actual operations, the Company continually balances its market position—first with monthly products, then with daily products, and finally with hourly products. The products used to balance the Company's forward position in the wholesale market are available in flat 25 megawatt (MW) blocks. The Company's load and resource balance, however, varies continuously each hour in quantities that may vary widely from a flat 25 MW block. Thus, in real world operations, the Company must continuously purchase or sell additional volumes to keep the system in balance.

In contrast, Aurora has perfect foresight and can model wholesale market transactions at whatever volume is necessary to balance the system. Because of Aurora's perfect foresight, it can balance the system with far fewer transactions. The DA/RT adjustment adds additional volumes and associated cost to NPC to more accurately model the transactions necessary to balance the Company's system.

Q. Has the Company proposed a refinement to the *price component* of the DA/RT in this case?

A. Yes. The Company proposes to maintain the refinement that was implemented in the 2023 TAM on a non-precedential basis. This refinement changes the DA/RT adjustment's price component from a flat value to a percentage of market price.

Q. Please explain how changing the DA/RT adjustment's price component from a flat value to a percentage of market price results in a DA/RT adjustment that is more reflective of actual operations.

A. Changing the price calculation to a percentage of the market prices aids in accounting for the volatility caused by prices and system conditions not captured in day-ahead transactions. Take, for example, a $5 price adder in an hour when the market price is $25. This resolves to a 20 percent price adder. But using the $5 price adder when market prices are $75 would fail to account for the system and market conditions during that hour. Using a 20 percent price adder during hours when market price is $75 would yield in a $15 price adder, which is more reflective of the system conditions. A key benefit of using a percentage adder is that it allows the modeling to capture intra-monthly variability. Subsequently, this is a significantly more accurate representation of real operating conditions experienced by the Company.

Q. Why has the transition to Aurora not resolved the need for a DA/RT price component?

A. As noted above, the basis of the DA/RT price component is founded in the historical price differences between the Company's purchases and sales as compared to the monthly average market prices. The fact that there are historical price differences between the Company's purchases and sales as compared to the monthly average market prices is agnostic to the model used to forecast Company purchases and sales. Therefore, the transition to Aurora has not resolved the basis for the DA/RT price component.

A. Reply to Staff

Q. Does Staff recommend modifications to the DA/RT *price component* in this case?

A. Yes. Staff recommends that the Commission reject the Company's proposed refinement to the DA/RT price component because there is not enough information in the record that the proposed changes better reflect intra-month market volatility.[14]

Q. How does a percentage adjustment better capture intra-month price variability as compared to a flat dollar adjustment?

A. In the testimony below, I provide analysis on the drivers of the DA/RT price component, including a discussion of historical hourly scaled monthly average market prices as compared to historical hourly scaled Company purchases and associated purchase prices across four years of historical data from 2019 to 2022. This analysis shows that the refinement proposed by the Company more accurately accounts for intra-month price variability in the context of the historical data.

Q. Why is it important to focus on Company purchases instead of Company sales?

A. Across the historical period, the total net peak expense incurred from Company purchases is approximately 5.8 times greater than the total net peak revenues gained from Company sales. Confidential Figure 4 provides an illustration of this along with the average four-year historical hourly shape of purchase volumes, sales volumes, purchase expenses and sales revenues. This data, along with the observation that throughout the historical period the Company is a net purchaser (importer) on a dollar and volume basis and that Aurora has no market caps on purchases highlights the outsized importance of purchased power and its attendant costs.

[14] Staff/200, Jent/8.

REDACTED

Confidential Figure 4

[redacted]

Q. What does the historical data show when comparing market prices to the Company's purchases?

A. Confidential Figure 5 uses data from 2019 to 2022 to create two curves—one illustrating hourly scaled average market-indexed prices and one illustrating hourly scaled average Company purchase prices. The difference between the curves is an illustration of the DA/RT price component. The concept of intra-month price variability is exhibited by the change in price levels across the day for the hourly scaled average market-indexed prices as compared to the hourly scaled average

Company purchase prices. This price variability is set forth numerically in Confidential Table 4, which shows the numeric difference between the two curves.

Confidential Figure 5

[redacted]

Confidential Table 4

Hour Ending	Average Historical DA/RT *Price Component's* Adder ($/MWh)
1	[redacted]
2	[redacted]
3	[redacted]
4	[redacted]
5	[redacted]
6	[redacted]
7	[redacted]
8	[redacted]
9	[redacted]
10	[redacted]
11	[redacted]
12	[redacted]
13	[redacted]
14	[redacted]
15	[redacted]
16	[redacted]
17	[redacted]
18	[redacted]
19	[redacted]
20	[redacted]
21	[redacted]
22	[redacted]
23	[redacted]
24	[redacted]

Q. Why do you refer to the variability as "intra-month" when the data appears to focus on variability within a day?

A. It is important to recall that the OFPC uses monthly prices, which are then scaled down to hourly prices. So intra-month price variability is exhibited as hourly price variability within each day of the month. In my testimony above and as illustrated in Confidential Figure 5, this intra-month price variability is presented as average hourly price variability across the four-year historical period for the average day.

Q. The DA/RT price component has historically been a flat dollar amount applied to the purchase and sales price. Does the historical data support this approach?

A. No. The historical data in Confidential Figure 5 and Confidential Table 4 shows intra-month variability in the DA/RT price component (i.e., the variability between the hourly scaled average market-indexed prices and the hourly scaled average Company purchase prices) is not constant across the day; the difference is generally greater as the price increases. If historical market prices supported the DA/RT price component as a flat dollar amount, then the historical values in Confidential Table 4 would not exhibit variability across the day but rather show consistency.

Confidential Figure 6 illustrates this variability in the actual historical DA/RT price component as compared to an illustration of a flat adder.

Confidential Figure 6

[redacted]

Q. Is Confidential Figure 6 a visual of historical market price curves in comparison to a flat DA/RT price component?

A. No. Confidential Figure 6 is a visual of what the historical DA/RT price component is, based solely on the historical relationship between actual market prices and actual Company purchases along with a comparison to a hypothetical flat adder that is separated into high load hour (HLH) and low load hour (LLH) components. That is to say, Confidential Figure 6 is a visual of Confidential Table 4 along with a comparison to a hypothetical flat adder that is separated into HLH and LLH components. Confidential Figure 6 is not a visual of a market price curve, even though it looks similar.

Q. Does the historical data support the usage of a percentage adder to more accurately account for intra-month price variability?

A. Yes. As illustrated in Confidential Figure 5 and in Confidential Figure 6, as the historical average market-indexed price increases, the spread between the historical average market-indexed price and the historical average buy price increases as well. This suggests that a percentage adder is more suitable for capturing the historical interplay between monthly average market prices and Company purchase prices. As illustrated in Confidential Table 4, the historical data definitively does not suggest that a flat adder is appropriate for capturing this intra-month dynamic. This means that the Company's refinement to the DA/RT price component is a more accurate representation of the difference between average market prices and the Company's transaction prices. Because the purpose of the DA/RT price component is to reflect this difference, the Company's refinement is consistent with the Commission's rationale for adopting the DA/RT adjustment in the 2016 TAM and repeatedly approving its use in the TAM forecast during the last seven years.

Q. Does Staff include any other recommendations related to the DA/RT adjustment?

A. Yes. Staff recommends that the "inherent issues with the DA/RT be addressed holistically with the Company's perceived shortcomings of its market cap methodology[.]"[15] The "inherent issues" Staff identifies relate to the price component of the DA/RT adjustment.

Q What is the basis for Staff's recommendation that both the DA/RT adjustment and market caps be addressed together?

A. Staff claims that both refinements relate to "market hub activity" so it is "intuitive that these two adjustments should be viewed together rather than analyzing them individually."[16]

Q. How do you respond to Staff's recommendation?

A. First, the Company disagrees that there are "inherent issues with the DA/RT" price component. The price component has worked well since it was adopted by the Commission nearly ten years ago and appropriately includes costs in the NPC forecast that were previously excluded. Although the adjustment is not perfect and has been refined over time, it has no inherent flaws, as I discuss in more detail below.

[15] Staff/200, Jent/9.
[16] Staff/300, Dlouhy/10.

Second, there is no relevant connection between the DA/RT adjustment and market caps that supports Staff's proposal to address both together because all cost components of the NPC forecast[17] relate to each other.

Q. What is Staff's "inherent issue" with the DA/RT adjustment?

A. Staff claims that the DA/RT price component is an "ad hoc adjustment that distorts market prices by making sales prices lower and purchase prices higher in the model than the Company faces in reality" and therefore the DA/RT price component improperly creates "artificial losses" for the Company that are then used to increase forecast NPC.[18]

Q. Does Staff's testimony consider both the *price* and the *volume* component of the DA/RT adjustment?

A. No. Staff does not consider that the DA/RT adjustment has two components—a *price component* and a *volume component*. Staff's testimony focuses solely on the *price component* in their discussion on "artificial losses" without reconciling Staff's recommendation with how the entirety of the DA/RT adjustment operates. Specifically, by design the DA/RT *volume component* used since the 2016 TAM adds into the NPC forecast a measure of historical arbitrage revenue to offset the impact of using a single price adjustment in the DA/RT *price component* when the sales price exceeds the purchase price (which is the single price adjustment that Staff characterizes as "making sales prices lower and purchase prices higher in the model than the Company faces in reality."). I discuss this *volume component* in more detail

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[17] 'Wholesale Sales Revenue', 'Purchased Power Expense', 'Fuel Expense' and 'Wheeling and Other Expense'.
[18] Staff/300, Dlouhy/9.

below and demonstrate that when viewed holistically, the DA/RT adjustment operates as intended and does not create the "artificial losses" Staff describes.

Q. Does Staff explain how the DA/RT adjustment creates the "artificial losses"?

A. No. Staff instead points to testimony it filed in the 2023 TAM.[19] In that case, Staff explained, "if PAC's buy price is lower than its sale price, [the DA/RT price component] calculates an amount that creates an artificial loss for the Company."[20] This happens because the DA/RT price component increases the purchase price and decreases the sales price thereby increasing overall NPC by increasing costs to purchase and decreasing revenues from sales. Staff calls this increase an "artificial loss," which Staff claims is an inherent flaw in the DA/RT price component.

Q. Has Staff raised this same concern before?

A. Yes. In the 2017 TAM, Staff objected to the DA/RT adjustment for the exact same reason:

> For some periods, PacifiCorp applies a different Price Adder than that suggested by the four-year history. Actual historic data indicates that in some months, purchases are on average less expensive than sales. This would result in a GRID purchase price below the GRID sale price within a single trading hub. At these prices, GRID would optimize by arbitraging within the same trading hub, maximizing both sales and purchases within the hub. PacifiCorp prevents GRID from performing this arbitrage by overriding the Price Adder calculation formula for these specific occurrences.[21]

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[19] Staff/200, Jent/10.

[20] *In the Matter of Pacificorp, dba Pacific Power, Transition Adjustment Mechanism*, Docket No. UE 400, Staff/200, Cohen/11.

[21] *In re of Pacificorp, dba Pacific Power, 2017 Transition Adjustment Mechanism,* Docket No. UE 307, Staff/200, Kaufman/6 (Jul. 8, 2016).

Q. How did the Commission resolve Staff's identical objection to the DA/RT adjustment in the 2017 TAM?

A. As noted above, the Commission affirmed the DA/RT adjustment and rejected Staff's argument.

Q. Do you agree that the DA/RT price component improperly creates artificial losses?

A. No. The feature of the DA/RT price component Staff disputes has been a critical component of the DA/RT since it was first adopted by the Commission in the 2016 TAM. Without the adjustment that Staff disputes, the DA/RT price component could result in a scenario where the buy price at a particular hub is lower than the sales price at the same hub. If the inputs to Aurora for a single market showed a purchase price that was less than the sales price, then Aurora would buy and sell arbitrarily (arbitrage) large volumes of power under this situation, but in reality, the volumes in question would be very limited. In the event that this rare situation occurred in reality, all rational market participants would take advantage of this free profit arbitrage opportunity until market prices reached equilibrium and the purchase price was greater than or equal to the sales price. Within the Aurora model no equilibrium can ever be reached, as increasing demand does not impact price.

Given the Aurora model's inability to handle this circumstance, when the average monthly sales price exceeds the monthly purchase price in the same market, a single price adjustment is used for both sales and purchases based on the volume-weighted average of the historical sales and purchases. This ensures the modeled price component of the DA/RT adjustment better reflects market reality.

Q. Can you provide a quantitative example demonstrating why the adjustment Staff disputes is necessary?

A. Yes. For simplicity, assume that the DA/RT adjusted Mid-Columbia sales price is $2.00 per MWh and the DA/RT-adjusted purchase price at Mid-Columbia is $1.00 per MWh for the same time period. If these are the price inputs in Aurora, then the model will purchase energy at Mid-Columbia for $1.00 and sell that same energy at Mid-Columbia for $2.00 creating a $1.00 profit per MWh bought and sold. Because the model would require no generation to support its ability to arbitrage in this way, it would make this simultaneous purchase and sale repeatedly until it hit the market capacity on sales (market caps). This cycle of repeated arbitrage behavior does not reflect market realities and would lead to absurd results.

Q. How does the DA/RT adjustment address the fact that it reduces the purchase price to prevent excessive and unrealistic arbitrage in the model?

A. The NPC increase from the DA/RT *price component's* adder resulting from an adjustment to reduce artificial arbitrage is remedied in the DA/RT *volume component*, which re-introduces revenue into the NPC forecast to offset that price component's decrease to revenues. In this case, the volume component added in historically supported arbitrage revenue of $7.4 million, total-company. When the DA/RT adjustment is viewed holistically, both price component and volume component together, there are no artificial losses that result from the price component's adders.

Q. How does the volume component re-introduce the revenue that is lost when the price component's sales price is reduced to equal the purchase price?

A. The volume component of the DA/RT adjustment includes historical arbitrage revenues, which are the revenues that Staff claims are artificially removed by the price component of the DA/RT adjustment.

Q. Has the Commission previously recognized that the DA/RT adjustment appropriately includes arbitrage revenues?

A. Yes. In the 2017 TAM where Staff raised the same issue around the so-called "artificial losses," Staff argued that the "DART price adders eliminate the value of arbitrage transactions."[22] The Commission rejected Staff's argument and found PacifiCorp's explanation persuasive that because arbitrage transactions are included in the historic DA/RT data, the benefits from arbitrage are incorporated into the volume component of the adjustment.[23] In that case, the Commission affirmed the DA/RT adjustment, which it had approved the previous year.

Q. Did Staff resurrect its argument that the DA/RT adjustment improperly excludes arbitrage revenues in any other TAMs?

A. Yes. In the 2018 TAM, Staff again argued that the DA/RT adjustment improperly excluded arbitrage revenues but focused on arbitrage across two market hubs, rather than arbitrage at a single hub.[24] Nonetheless, the Commission again affirmed the DA/RT adjustment and rejected Staff's argument that the adjustment improperly excluded arbitrage revenue.

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[22] Order No. 16-482, at 12.
[23] Order No. 16-482 at 12 ("PacifiCorp respond[ed] that the adjustment properly includes arbitrage transactions."); *see also In the Matter of PacifiCorp, dba Pacific Power, 2017 Transition Adjustment Mechanism*, Docket No. UE 307, PAC/400, Dickman/32 (Aug. 1, 2016).
[24] *In the Matter of PacifiCorp, dba Pacific Power, 2018 Transition Adjustment Mechanism*, Docket No. UE 323, Staff/200, Kaufman/12 (Jun. 9, 2017).

Q. Turning back to the relationship between the DA/RT price component and market caps, Staff claims that the "artificial losses" created by the DA/RT price component has an opposite effect "on the same general subcategory of the total TAM forecast" as the market caps and therefore "Staff believes that they can be paired together to help the AURORA model match up better to reality."[25] Do you agree?

A. No. The fact that both adjustments impact market sales does not mean that they can be paired together and addressed holistically—particularly because the supposed flaw in the DA/RT price component underlying Staff's recommendation does not actually exist. That is, because the DA/RT adjustment includes historical arbitrage revenues in the volume component, there is no flaw that needs to be offset by an increase in market caps.

Q. Has the Commission previously addressed the relationship between the DA/RT adjustment and market caps?

A. Yes. When PacifiCorp first introduced the DA/RT adjustment in the 2016 TAM, AWEC witness Mullins, on behalf of ICNU, recommended that the Commission eliminate market caps if it approved the DA/RT adjustment.[26] The Commission rejected ICNU's adjustment in that case.

B. Reply to Vitesse

Q. Please describe Vitesse's position on the DA/RT adjustment.

A. Vitesse recommends that the Commission not adopt the Company's proposed

[25] Staff/200, Jent/10.
[26] Order No. 15-394 at 3.

refinement to the DA/RT price component on a precedential basis in this case to allow the parties additional time to review the adjustment.[27] Vitesse also identifies two concerns and proposed changes to the DA/RT price component.[28] However, Vitesse does not recommend that the Commission approve Vitesse's proposed modifications in this case, consistent with its primary recommendation that the Commission make no change to the DA/RT price component in this case to allow the parties additional time to review.[29]

Q. How do you respond to Vitesse's overall recommendation to defer adopting of the percentage price adder to allow additional time for review?

A. The Company disagrees that the parties require additional time to review the Company's refinement to the price component of the DA/RT adjustment. The Company first proposed and implemented the refinement in the 2023 TAM, so the parties have had more than a year to review. Moreover, when the Company first proposed the DA/RT adjustment in the 2016 TAM, Staff's primary objection was that there was insufficient time to review, similar to Vitesse's position here. The Commission rejected that argument, concluding that "[p]arties have had sufficient time and opportunity to review and assess the proposal."[30] Given that the parties here have had even more time to review the refinement here and the fact that the refinement is limited in scope, there is no basis to delay approval pending additional review.

[27] Vitesse/100, Johnson/7.
[28] Vitesse/100, Johnson/7–8.
[29] Vitesse/100, Johnson/7–8.
[30] Order No. 15-394 at 4.

Q. Please describe Vitesse's first recommended modification to the price component of the DA/RT adjustment.

A. Vitesse recommends that the calculation of the percent price adders be volume weighted by the volume of balancing purchases made each month.[31]

Q. How do you respond to Vitesse's recommendation?

A. The Company agrees that Vitesse's recommendation is reasonable and proposes to adopt this recommendation.

Q. Please describe Vitesse's second recommended modification to the DA/RT price component.

A. Vitesse describes the same "artificial losses" scenario identified by Staff and explained above.[32] Vitesse acknowledges that Aurora cannot function when the purchase price is lower than the sales price and therefore some adjustment is necessary but claims that the use of a flattened price artificially decreases the volume of purchases and sales modeled in Aurora.[33] Vitesse proposed no "long-term" solution to this issue but instead provides an interim recommendation—when calculating the dollar impact of the DA/RT price component, Vitesse recommends that the Company make an out-of-model adjustment that multiplies the volume of purchases and sales made in Aurora by the purchase and sales price, rather than by the flattened average of the two. Although Vitesse does not recommend that the Commission implement this modification in this case, Vitesse has roughly estimated

[31] Vitesse/100, Johnson/11.
[32] Vitesse/100, Johnson/12–13.
[33] Vitesse/100, Johnson/14–15.

the impact as a decrease to NPC of approximately $10 million total-company.[34] However, as I explain above, this is a double count of the $7.4 million total-company decrease to the NPC forecast through the DA/RT volume component's introduction of historical arbitrage revenue.

Q. How do you respond to Vitesse's second recommendation?

A. Vitesse's recommendation should be rejected. As an initial matter, and as discussed above in response to Staff, the issue of "artificial losses" identified by Vitesse and the attendant remedy in the DA/RT volume component has been a part of the DA/RT adjustment since it was first approved in the 2016 TAM. There is nothing new about these elements of the DA/RT adjustment. More importantly, as discussed above, the increased NPC resulting from the use of an average purchase and sales price when those prices are inverted is offset by the volume component of the DA/RT adjustment, which decreases NPC to account for historical arbitrage revenues. Vitesse's adjustment here is therefore double-counting arbitrage revenues.

Q. Vitesse is also concerned that the data set used to calculate the DA/RT adjustment includes trading hubs with very small volumes of system balancing transactions.[35] How do you respond?

A. As an initial matter Vitesse does not identify these "trading hubs with very small volume" or quantify the volume of transactions that Vitesse considers small. However, from the data set in the Initial Filing, the total annual dollars transacted at individual trading hubs range from $2.42 million to $75.7 million total-company.

[34] This $9.96 million total-company also includes the impact of Vitesse's volume weighted adjustment. See Vitesse/100, Johnson/16.
[35] Vitesse/100, Johnson/17.

The Company does not find these values to be small and parties have contested the TAM NPC forecast over far less.

Q. Finally, Vitesse is concerned that because the DA/RT adjustment is based on historical price and volume data, it "embeds" historical forecasting performance in future rates.[36] How do you respond?

A. As an initial matter, it is important to clarify the type of forecasting Vitesse discusses to avoid confusion. Vitesse claims that the Company is embedding its "historic forecasting performance in future rates" and then goes on to express concern about the Company not demonstrating that its "forecasting is reasonably accurate or to improve its forecasts."[37] However Vitesse is not referring to the prior NPC forecasts. Rather, Vitesse is referring to the reality of load service in actual operations where, for example, in the day-ahead horizon the Company must forecast the amount of customer load needing to be served on the next day.

Vitesse is concerned that the Company has not demonstrated that its forecasts made in actual operations are accurate and therefore it is concerning to Vitesse that the Company's NPC forecast is based on historical data that is partly based on those forecasts made in actual operations.[38]

Q. Does Vitesse's concern have merit?

A. No, not in its context. Vitesse's concern is not specifically related to the DA/RT price component. Vitesse's concern is related to the fundamental nature of power costs forecasts in the TAM and their use in ratemaking. Within the power cost

[36] Vitesse/100, Johnson/17.
[37] Vitesse/100, Johnson/17.
[38] Vitesse/100, Johnson/17.

forecasting mechanism itself, Vitesse is essentially arguing that the volatility in prices and other system conditions are increasing and then Vitesse uses that argument to have a discussion on holding the utility accountable for its forecasts in actual operations. This discussion has no immediate relevance to the merit of the DA/RT price component.

C. Reply to AWEC

Q. Please describe AWEC's position on the DA/RT adjustment.

A. AWEC recommends that the Company eliminate the price component of the DA/RT adjustment but retain the volume component of the DA/RT adjustment.[39]

Q. As an initial matter, AWEC claims that the DA/RT adjustment in its entirety is unnecessary now that the Company is using Aurora instead of GRID.[40] Do you agree?

A. No. The *price component* modifies the OFPC, which is an input to Aurora, just like the OFPC was an input to GRID. The DA/RT adjustment's price component exists because the OFPC is a single price but: (1) the Company faces different prices when purchasing energy as compared to when selling energy; and (2) those prices are on average unfavorable relative to the OFPC as the Company typically purchases at prices above the OFPC and sells at prices below the OFPC. Because neither GRID nor Aurora internally account for the historical differences between purchase and sales prices, the DA/RT adjustment's price component is critical to ensuring a more

[39] AWEC/100, Mullins/9.
[40] AWEC/100, Mullins/8.

accurate NPC forecast and agnostic to the production cost model used to create the NPC forecast.

The DA/RT adjustment's *volume component* exists because there are multiple time horizons in actual operations (month-ahead, day-ahead, hour-ahead, etc.) and energy is traded in multi-hour blocks in many of these horizons. Aurora, however, is a single stage model that simulates hourly dispatch all at once, with no segregation of time horizons, and executes transactions to within a fraction of a MW. The DA/RT adjustment's volume component introduces the inefficiencies and associated costs that come with these multiple time horizons and multi-hour block products into the NPC forecast.

Q. AWEC claims that the DA/RT adjustment is unnecessary because Aurora and GRID use "entirely different approaches to calculate dispatch" and Aurora's dispatch is not as optimized as GRID.[41] Do you agree?

A. No. Limitations in GRID were primarily a lack of co-optimization between energy and ancillary services, unit commitment logic that was decades out of date, an inability to constrain fuel usage on thermal resources, and no concept of storage resources or GHG emissions. Aurora improves on all these aspects. Aurora calculates a transmission-constrained, least-cost dispatch using effectively simultaneous unit commitment and economic dispatch processes, which are driven by an advanced hourly mixed integer program and linear program, respectively. Furthermore, Aurora co-optimizes both energy and ancillary services as opposed to the inefficient sequential optimization employed by GRID, and additionally, allows

[41] AWEC/100, Mullins/8.

for the application of a myriad of constraints inclusive of ramp rate constraints, GHG emissions constraints and fuel constraints, all of which were either not present in GRID, or of limited functionality.

AWEC's description of Aurora is incorrect and provides no basis to reject the DA/RT price component.

Q. Was AWEC able to provide any documentation from Aurora verifying its description of Aurora's optimization?

A. No. It appears that AWEC's only basis for claiming that Aurora may not produce a least-cost optimization is the result of AWEC's own Aurora modeling that removed a small amount of short-term firm transmission from the model and resulted in an increase in overall NPC of roughly 0.0017 percent.[42] Based on this result, AWEC claims Aurora is not a least-cost optimized model. However, as I explain below in Section XV of my testimony, the 0.0017 percent variance is: (1) based on flawed analysis; (2) lacking recognition of the difference between NPC in the TAM as compared to *all* variable power costs; and (3) "noise" in the model and in no way suggests that Aurora does not produce an optimized dispatch.

Q. Is AWEC's criticism of Aurora's imperfect optimization contrary to AWEC witness Mullins' prior testimony?

A. Yes. In the 2022 TAM, AWEC testified that the "AURORA model contains a more sophisticated commitment and dispatch logic than the GRID model, which better mimics the actual operation of PacifiCorp's gas plants."[43] This prior testimony

[42] This percentage was calculated based on an NPC increase of approximately $45,000 total-company relative to an overall NPC of $2.642 billion total-company in the Initial Filing. See AWEC/100, Mullins/8–9.
[43] *In the Matter of PacifiCorp, dba Pacific Power, 2022 Transition Adjustment Mechanism*, Docket No. UE 390, AWEC/200, Mullins/4 (Aug. 26, 2021).

cannot be squared with AWEC's current claim that Aurora has less optimized dispatch than GRID.

Q. AWEC further claims that using the DA/RT adjustment in Aurora is producing the opposite effect that it did with GRID.[44] What is the basis for this claim?

A. AWEC ran Aurora with and without the DA/RT price component and concluded that the DA/RT adjustment from the Aurora run without the price component is closer to the historical DA/RT adjustment.[45] From this comparison AWEC concludes that eliminating the DA/RT price component produces a more accurate forecast because it is closer to the historical averages. However, AWEC's simplistic comparison is merely observing that there is a substantial increase (a paradigm shift) in reliance on purchased power in the Initial Filing's NPC forecast resulting from the combination of coal supply limitations, the OTR, the Jim Bridger gas conversion, the removal of the Klamath dams, and the Washington Cap and Invest Program. AWEC conflates the purpose of the two components of the DA/RT adjustment and AWEC's conclusions stem from this misunderstanding that I explain in more detail below.

Q. Turning to AWEC's specific recommendation, why does AWEC recommend removing only the price component of the DA/RT adjustment?

A. AWEC claims that volume component of the DA/RT adjustment renders the price component "perfunctory, except to the extent that [the price component] modified the way thermal plants were dispatched."[46]

[44] AWEC/100, Mullins/8.
[45] AWEC/100, Mullins/8.
[46] AWEC/100, Mullins/7.

Q. Do you agree?

A. No. AWEC mischaracterizes the two components of the DA/RT adjustment. As discussed above, the purpose of the DA/RT adjustment is to more accurately capture the true cost of balancing the Company's system in the short-term markets by: (1) adjusting forward market prices (the OFPC) to reflect historical variations between the average market-indexed prices over each month and actual realized prices for the Company's day-ahead and real-time transactions in that month (***price component***); and (2) adjusting system balancing transaction volumes to reflect the inefficiencies and associated costs of the operational practice of transacting on a monthly basis using, as an example**,** standard 25 MW increment, 16-hour block products, rebalancing on a daily basis using standard 25 MW increment eight-hour block products, and finally closing the remaining position on an hourly basis in real-time markets (***volume component***). These two steps are designed to accomplish two different tasks and accounting for the inefficiencies associated with trading in multi-hour block products in actual operations (i.e., a MWh (volume) trading inefficiency) does nothing to change the persistent deviation between an indexed market price and the Company's real market prices faced in actual operations (i.e., a $/MWh (price) inefficiency).

Q. Is AWEC's testimony here consistent with its prior positions on the DA/RT?

A. No. Just last year in the 2023 TAM, AWEC witness Mullins testified that the DA/RT *volumes* are "a perfunctory feature of the DA/RT adjustment, and have zero impact on NPC."[47] In other words, this year, the price component is "perfunctory" while last year the volume component was "perfunctory."

Q. Has the Commission ever addressed recommendations to eliminate only one component of the DA/RT adjustment?

A. Yes. In the 2017 TAM and 2018 TAM, Staff argued the opposite of AWEC and recommended that the Commission eliminate the volume component of the DA/RT adjustment.[48] In the 2018 TAM, AWEC witness Mullins made the same argument he makes here:

> The Company characterizes the DA/RT adjustment as having two components: 1) a price component; and 2) a volume component. I, however, disagree that it is appropriate to characterize the adjustment in such a manner. Based on the way that the adjustment is calculated, the complicated mechanics underlying the price and volume components are irrelevant. As a final step in the Company's implementation of the DA/RT adjustment, the Company applies a plug, outside of the GRID model, to force the total impact of the DA/RT adjustment to tie to the historical average, which in this case the Company has proposed as the 60 months ending in June 2016. Accordingly, it is more appropriate to view the Company's adjustment as a single adjustment based solely on the historical averages, rather than viewing it as two, largely arbitrary, components.[49]

In both the 2017 and 2018 TAMs (and in all others where it was litigated), the Commission retained both components of the DA/RT adjustment, recognizing that they work together to reflect costs that are incurred in actual operations but that are not inherently present within the Company's production cost model.[50]

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[47] *In the Matter of PacifiCorp, dba Pacific Power, 2023 Transition Adjustment Mechanism*, Docket No. UE 400, AWEC/100, Mullins/17 (May 25, 2022).
[48] Order No. 16-482 at 12; Order No. 17-444 at 6.
[49] *In the Matter of PacifiCorp, dba Pacific Power, 2018 Transition Adjustment Mechanism*, Docket No. UE 323, ICNU/100, Mullins/9–10 (Jun. 9, 2017).
[50] Order No. 16-482, at 13–14.

Q. Did AWEC's recommendation cause the Company to further investigate the modeling of the DA/RT adjustment in this year's TAM?

A. Yes. AWEC's recommendation raised a concern because in this case the price component of the DA/RT adjustment increases NPC, while the volume component reflected in the Initial Filing decreases NPC. So AWEC's recommendation effectively cherry-picked the benefits of the DA/RT adjustment without having accounted for the attendant costs.

However, on further investigation spurred by AWEC's testimony, the Company discovered that the volume component of the DA/RT adjustment was not functioning as the Commission intended when the adjustment was approved. In this TAM, the volume component was substantially *decreasing* NPC (by $97 million total-company in the Initial Filing), even though the volume component is designed to capture inefficiencies and attendant *costs* in actual operations that are not captured in Aurora, as discussed above. Real-world inefficiencies in trading cannot produce such substantial revenue (lowers NPC) when compared to Aurora's perfectly efficient optimized system dispatch.

Q. How is the DA/RT adjustment's volume component implemented in Aurora?

A. Identical to the prior implementation in GRID approved by the Commission, the volumetric component of system balancing transactions within the NPC forecast is increased, as an out of model adjustment, to account for the use of multi-hour block products in actual operations. System balancing purchase volumes are increased by an equal and offsetting amount to system balancing sales volumes so that the net volumetric position of the NPC forecast is unchanged.

Q. How does the increase in system balancing volumes impact revenues and costs within the context of the NPC forecast?

A. Because the volumes of Aurora's system balancing transactions are increased, the incremental volumes must be associated with prices otherwise they would represent free energy (i.e., no revenues received or costs incurred for market sales or purchases). These volumes are priced by comparing historical system balancing transactions to forecast system balancing transactions using 48 months of historical transaction history as a proxy for the increased costs associated with the operational practice of trading in multi-hour block products.

Q. With this background in mind, why is the DA/RT adjustment's volume component functioning incorrectly?

A. As the incremental increase in sale volumes is identical to the incremental increase in purchase volumes, the revenues from the sales volume was allowed to be greater than the costs from the purchase volumes producing artificial arbitrage within the NPC forecast. Specifically, the DA/RT volume component bought a certain volume of energy at a low price and then sold the same volume of energy at a high price in the same time period. Because the DA/RT adjustment is meant to mimic actual operations, this result meant the use of inefficient multi-hour block products in actual operations created substantial efficiencies within the NPC forecast that lowered NPC, contrary to the impacts of these multi-hour block products in actual operations, which increase NPC, as explained here and in prior TAM testimony and Commission orders.

Q. Has the Company accounted for this artificial arbitrage so that the DA/RT adjustment functions properly?

A. Yes. Whenever the monthly sales revenue from an incremental volume adjustment at a trading hub exceeds the monthly purchase cost for the same amount of volume in the same time period: 1) a single price adjustment is made such that both the monthly sales revenue and the monthly purchase cost offset for no net impact to the NPC forecast; and 2) the monthly sales revenue is adjusted upwards to re-introduce arbitrage revenues from the historical data into the NPC forecast. This averaging to create a single price adjustment for both sales and purchases to remove *artificial* arbitrage opportunity is identical to the adjustment calculated in the DA/RT price component since its inception in the 2016 TAM as explained in further detail above in my testimony. Furthermore, this single price adjustment retains the arbitrage revenues that offset losses in the DA/RT price component.

Q. Does the DA/RT volume component still include historical arbitrage revenues?

A. Yes. Within the 48-month historical average that supports the pricing of the incremental DA/RT volumes, the Company continues with the DA/RT adjustment volume component's precedent of including historical arbitrage transactions. Furthermore, within the error correction these arbitrage benefits are explicitly retained. This reduces the cost of the DA/RT volume component and is realistic because it reflects the historical availability of such opportunities. The removal of artificial arbitrage discussed above is a correction for the artificial arbitrage *created by* the DA/RT volume component within the 2024 TAM NPC forecast and separate from the real historical arbitrages that are normalized into the NPC forecast.

Q. Does the corrected DA/RT volume component now accurately reflect the Company's actual operations?

A. Yes. Arbitrage opportunities are no longer *artificially* created in the NPC forecast. This is true for both the volume component as well as the price component.

VI. MARKET CAPACITY LIMITS

Q. As background, please explain why Aurora requires market caps.

A. Like GRID, Aurora operates with perfect foresight and assumes unlimited market depth and full liquidity for the markets in which PacifiCorp makes off-system sales, unless informed otherwise. Aurora would therefore allow unlimited off-system sales at every market at any time of the day or night—an assumption that is very different from PacifiCorp's actual, historical experience.

To more realistically model actual market conditions, PacifiCorp has included market caps for sales since it introduced the GRID model in 2002.[51]

Q. How were market caps first implemented in GRID?

A. PacifiCorp originally modeled market caps in graveyard hours only. In the 2012 TAM, docket UE 227, PacifiCorp refined its market caps to specify market depth for sales during all hours based on historical average sales from the most recent 48-month period for each trading hub, each month, segregated by HLH and LLH periods.[52] This refined approach, known as the "average of averages" method, allowed for additional sales and reduced NPC compared to PacifiCorp's original graveyard market caps. At PacifiCorp's suggestion, the Commission adopted the

[51] *In the Matter of PacifiCorp dba Pacific Power, 2013 Transition Adjustment Mechanism*, Docket No. UE 245, Order No. 12-409 at 3–4 (Oct. 29, 2012).
[52] *In the Matter of PacifiCorp, dba Pacific Power, 2012 Transition Adjustment Mechanism*, Docket No. UE 227, Order No. 11-435 at 21 (Nov. 4, 2011).

average-of-averages approach in docket UE 227 on a non-precedential basis to allow an opportunity for additional review.[53]

In the 2013 TAM, docket UE 245, ICNU and Staff argued for elimination of market caps, a position the Commission rejected:[54]

> As Pacific Power observes, market caps have always been part of GRID and neither Staff nor ICNU persuasively argue that GRID, as it currently exists, no longer needs market caps. Based upon the evidence presented in this proceeding, we conclude that some form of market caps continue to be needed in GRID as it is now constructed.[55]

At the same time, the Commission accepted Staff's and ICNU's argument that the average-of-averages market cap methodology "overstates expected NPC."[56] Thus, the Commission adopted Staff's "alternative recommendation that essentially split the difference between the company's approach and Staff's recommended no cap approach."[57] This alternative methodology, referred to as the "maximum-of-averages" approach, sets "market caps on the highest of the four most recently available relevant averages for each trading hub, each month, and differentiated by on- and off-peak hours."[58]

Under the maximum-of-averages approach, the Company had to use the most extreme outlier cap value supported by the historical record for every other market hub, resulting in sales that consistently exceed historical averages. This approach

[53] Order No. 11-435 at 23.
[54] Order No. 12-409 at 5–8.
[55] Order No. 12-409 at 7.
[56] *In the Matter of PacifiCorp, dba Pacific Power, 2013 Transition Adjustment Mechanism*, Docket No. UE 245, Order No. 13-008 at 1–2 (Jan. 15, 2013) (denying motion for reconsideration).
[57] Order No. 13-008 at 1.
[58] Order No. 12-409 at 7–8.

contrasts with the average-of-averages method, which includes extreme outlier values in the four-year average but does not rely on them exclusively to set the market cap.

Q. What prompted PacifiCorp to recommend a change to market caps in the 2022 TAM?

A. In every Power Cost Adjustment Mechanism (PCAM) filing since 2012, when it was first adopted, the Company's actual NPC data demonstrated that the Company has persistently under-recovered its NPC in Oregon rates, which indicated that an average of averages market caps would not overstate expected NPC. In PacifiCorp's 2020 General Rate Case, docket UE 374, PacifiCorp sought changes to its PCAM. In response, Staff filed testimony analyzing PacifiCorp's NPC under-recovery between 2017–2019, relying on PacifiCorp's past PCAM filings.[59] Referring to two market transaction types, purchases and sales, Staff concluded that only one—sales—was "largely inaccurate in the forecast."[60] Staff testified that a "gross over-estimation of the sales benefit" was "apparent in both the dollar and MWh metrics."[61]

In its final order in docket UE 374, the Commission invited PacifiCorp to propose modeling changes in the TAM to increase its NPC forecast accuracy specifically concerning off-system sales:

> The TAM is an annual filing and PacifiCorp has an annual opportunity to improve its forecast, just as it did in the 2016 TAM when it introduced the DA/RT mechanism to increase the volume and modeled cost of balancing transactions to increase GRID's balancing costs. PacifiCorp does not necessarily need to develop a complex new adjustment, but may be able to improve its forecast accuracy with straightforward inputs or limits. For example, Staff shows that PacifiCorp's sales to market (also referred to as off-

[59] *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 374, Staff/2400, Gibbens/19–22 (Jul. 24, 2020).
[60] Docket No. UE 374, Staff/2400, Gibbens/22.
[61] Docket No. UE 374, Staff/2400, Gibbens/22.

> system sales) are being over-forecast, finding a "gross over-estimation of the sales benefit." PacifiCorp did not address the feasibility of reducing this component of its forecast and it is something that may be considered in the TAM. [62]

Q. Did the Commission modify the market caps in the 2022 TAM?

A. Yes. In the 2022 TAM, PacifiCorp requested that the Commission modify the market caps to revert to the average of averages methodology. The Commission did not adopt the Company's recommendation but did modify the market caps using a Staff proposal that set the caps using the "third quartile of averages" method, which averages the two highest values of the four highest monthly sales at each hub.[63] This modification reduced the market caps relative to the maximum of averages methodology.

Q. Did the Commission make any specific findings in its 2022 TAM order?

A. Yes. Most importantly, the Commission found that the record "support[ed] PacifiCorp's position that GRID does over forecast off-system sales with the maximum of averages market caps" and that the "data alone supports PacifiCorp['s] argument that from a rate-setting perspective, the average of averages is reasonable as it most closely approximates the historical average over the last four years."[64] But the Commission also noted that the data from 2021 and 2022 showed that "GRID produced a lower volume of sales even with the maximum of averages market cap, and it is too soon to know if that adjustment will bring the forecast closer to actuals."[65]

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[62] *In the Matter of PacifiCorp, dba Pacific Power Request for a General Rate Revision*, Docket No. UE 374, Order No. 20-473 at 130 (Dec. 18, 2020) (footnotes omitted).
[63] Order No. 21-379 at 26.
[64] Order No. 21-379 at 27–28.
[65] Order No. 21-379 at 28.

The Commission also acknowledged the transition away from GRID and to Aurora and therefore clearly stated that its "findings on market caps [were limited] to the 2022 TAM only."[66]

Q. Did PacifiCorp propose a modification to market caps in the 2023 TAM?

A. Yes. The Company recommended using the average of averages methodology for calculated market caps in Aurora. The case was settled, and the final NPC modeling included the average of averages market caps on a non-precedential basis.

Q. Please explain why PacifiCorp has again recommended use of the average of averages methodology for calculating the market caps in Aurora.

A. As noted above, Aurora is functionally the same as GRID in that it will transact in the market at unrealistic levels without a constraint, like market caps. Therefore, the Company has again recommended that the market caps be set using the average of averages approach.

Q. Is the average of averages methodology used to set the market caps used in PacifiCorp's other states?

A. Yes. Oregon is the only state that has adopted higher market caps and therefore using the average of averages market cap methodology will align the Company's NPC forecast in each jurisdiction.

Q. Have forecast off-system sales continued to exceed actual off-system sales?

A. Yes. Below, in Confidential Table 5, is an updated table that the Company provided in response to Bench Request 4 in the 2022 TAM and that the Commission included in Order No. 21-379.

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[66] Order No. 21-379 at 27.

Confidential Table 5

Year (Filing and Method)	Short-Term Sales (MWh) Actual	Forecast	(Below)/Above Forecast
2012	[redacted]	[redacted]	[redacted]
2013	[redacted]	[redacted]	[redacted]
2014	[redacted]	[redacted]	[redacted]
2015	[redacted]	[redacted]	[redacted]
2016	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]
2023 (Final Average of Averages)		[redacted]	
2024 (Reply Third Quartile of Averages)		[redacted]	
2024 (Reply Average of Averages)		[redacted]	

Note: The actual values in Confidential Table 5 are net of bookouts, which are not included in the forecast.

Q. What additional information is shown in Confidential Table 5, relative to the data included in the record of the 2022 TAM when the Commission approved the third quartile of averages methodology?

A. First, forecast off-system sales for 2021—which used the **maximum** of averages methodology—were *nearly double* the actual off-system sales.

Second, forecast off-system sales for 2022—which used the **third** quartile of averages methodology—were *more than double* the actual off-system sales.

Third, using the **third** quartile of averages methodology for the 2024 forecast produces forecast off-system sales that are higher than actual off-system sales for 2019, 2020, 2021, and 2022.

Fourth, even using the **average** of averages methodology for the 2024 forecast produces forecast off-system sales that are higher than actual off-system sales for 2021 and 2022. As discussed in more detail below, this fact is particularly critical given that trends show a definitive decrease in market transactions.

Q. If the 2024 TAM NPC forecast were to show reasonable levels of historical sales volumes under a certain market cap methodology, does that render the methodology unnecessary?

A. No. Market caps are analogous to guardrails on a road bridge. In this guardrail analogy, an observation of no vehicle accidents within a year does not imply that the guardrails serve no function, and it would be imprudent to remove those guardrails. Similarly, in the NPC forecast if sales volumes are considered reasonable (I discuss below why the 2024 forecast sales volumes are not), a reasonable market caps methodology would still be needed to ensure that forecast sales volumes stay within reasonable levels.

Q. Does the third quartile of averages methodology show reasonable levels of historical sales volumes?

A. No. **Even with** limited generation availability due to new operating and policy conditions such as coal supply limitations, the OTR, the Jim Bridger gas conversion, the removal of the Klamath dams, and the Washington Cap and Invest Program: (1) the third quartile of averages methodology shows forecast 2024 sales volumes of [redacted] which are **still higher** than the actual 2019, 2020, 2021 and 2022 sales volumes; (2) the average of averages methodology shows forecast 2024 sales volumes of [redacted] which are **still higher** than the actual 2021 and 2022 sales volumes; and (3) both of these methodologies produces sales volumes that are well in excess of the clear downward trend in actual market sales discussed in detail below. This means that even with the myriad of restrictions on generation availability in the 2024 TAM NPC forecast, the third quartile of averages market caps methodology is still over-forecasting sales volumes.

Q. Has the excessive forecast of off-system sales in prior dockets contributed to the Company's under-recovery of NPC in Oregon?

A. Yes. Indeed, in PacifiCorp's last general rate case, both Staff and the Commission concluded that the over-forecast of off-system sales has contributed to the Company's under-recovery of NPC in Oregon.[67] Furthermore, one of the drivers of the TAM NPC under-forecasts that triggered the PCAM in calendar years 2021 and 2022 is the market caps methodologies, which were the maximum of averages and the third quartile of averages respectively.

A. Reply to Staff

Q. Please describe Staff's recommendation.

A. Staff recommends that the Commission require the use of the third quartile of averages methodology on a non-precedential basis.[68] Staff argues: (1) the third quartile of averages methodology better aligns with the operational realities of transacting in the open market; (2) there is insufficient evidence that the average of averages methodology produces a more accurate forecast than the third quartile of averages methodology; and (3) even if the third quartile of averages methodology

[67] Order No. 20-473 at 130.
[68] Staff/300, Dlouhy/6.

over-forecasts off-system sales, that over-forecast effectively offsets the under-forecast of off-system sales resulting from the DA/RT adjustments' creation of "artificial losses" (discussed above in Section V of my testimony).[69]

Q. As an initial matter, did Staff acknowledge that Aurora over-forecasts sales?

A. Yes. Staff analyzed the Company's benchmark study that used 2019 actual data to validate the accuracy of Aurora. In the context of the benchmark study, Staff testifies that Aurora over-forecasts sales, noting that the "model is essentially saying that PacifiCorp will generate more than twice as much as they actually do."[70]

Q. Turning to Staff's first argument, do you agree that the third quartile of averages methodology better aligns with operational realities?

A. No. Staff claims that "there is no true cap to the amount of energy that the Company can sell to or buy from the market hubs."[71] This is untrue. In fact, the Company faces market capacity limits at all its trading hubs. To be clear, market capacity limits refer to the amount of energy that other market counterparties are willing to purchase in aggregate from PacifiCorp. More specifically, market capacity limits represent a threshold above which no one else can be found in the bilateral electricity markets to take the Company's energy at or above the Company's cost of producing that energy. In reality there are practical limits to the ability or willingness of counterparties to purchase energy in the bilateral markets across all entities inclusive of PacifiCorp.

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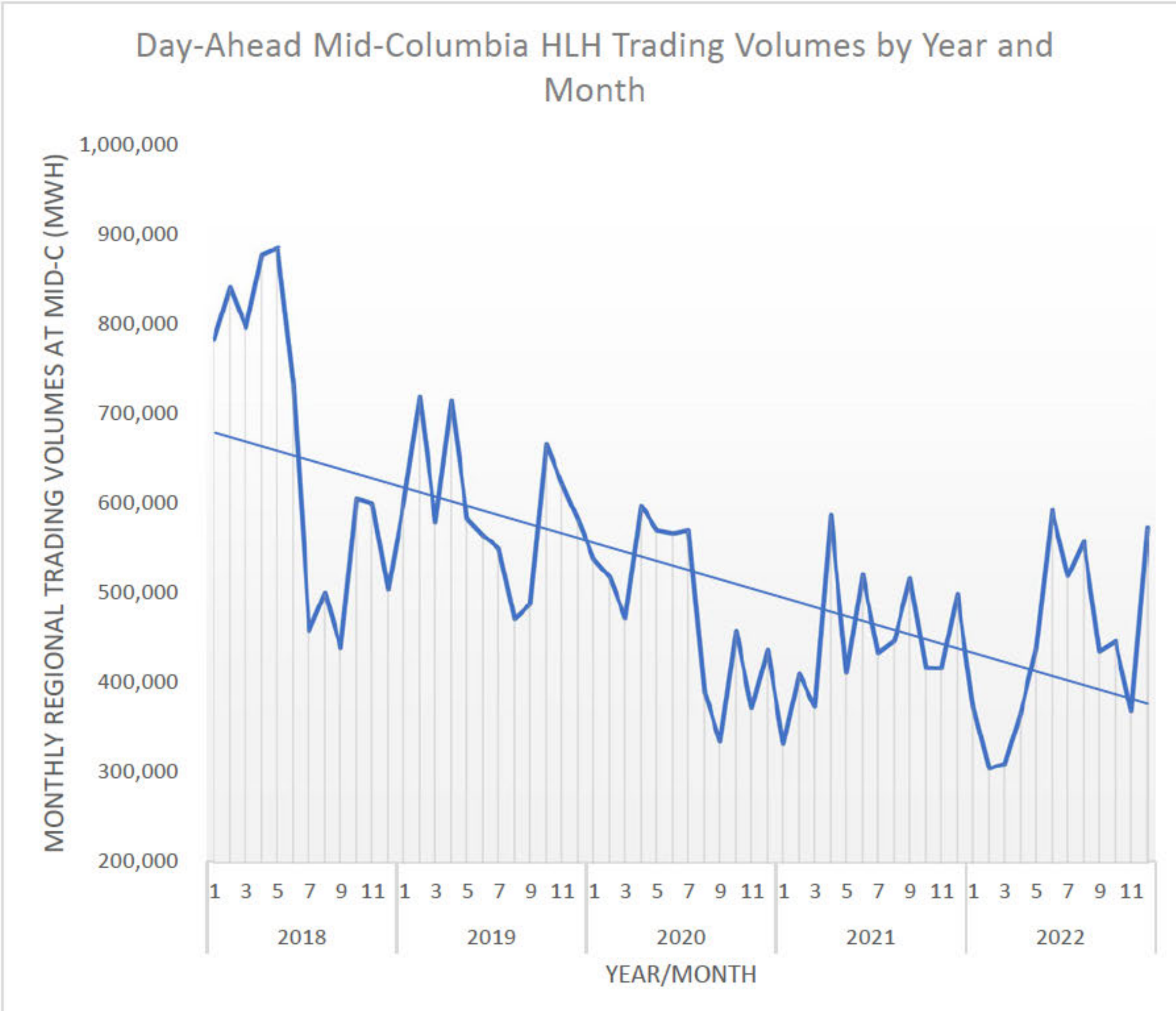
[69] Staff/300, Dlouhy/6–7.
[70] Staff/200, Jent/30.
[71] Staff/300, Dlouhy/7.

Q. Is there empirical evidence that there are market capacity limits that impact PacifiCorp's ability to make off-systems sales?

A. Yes. The volume of transactions in regional wholesale markets has been steadily declining in recent years, which supports a lower market cap. This decline is evident by examining data from the Intercontinental Exchange (ICE), which is the primary platform used to trade energy on a day-ahead basis in the western interconnection. Data from ICE at the Mid-Columbia trading hub over the HLH show that trading volumes have been consistently trending downwards over the past five years, from 2018 to 2022. Because a trade requires two counterparties, a buyer and a seller, a decrease in trading volumes year over year implies lower market sales volumes year over year across the Mid-Columbia region, [redacted]. This ICE data is illustrated in Figure 7.

Figure 7



Q. How do the lower year-over-year sales volumes across the region compared to the Company's year-over-year sales volumes?

A. The Company's year-over-year sales volumes in the day-ahead bilateral markets exhibit the same diminishing trend. This trend is illustrated in Confidential Figure 8, which shows total-company sales data, as used to directly calculate the market caps in this TAM and in prior TAMs.

Confidential Figure 8

[redacted]

Q. How do the market caps relate to the Company's historical sale volumes?

A. They are the same thing, expressed in different units and averaged over time. Whereas Confidential Figure 8 shows a measure of total sales volume by month for the past four years, the market cap methodology derives more detailed granularity from the same total sales volume data by first calculating the average hourly sales volume by month,[72] trading hub and HLH/LLH for the past four years and then, to

[72] The market caps methodology calculates a total sales volume by month and then normalizes that value over each hour of the month to derive an hourly limit.

derive the monthly market cap for 2024, averaging the four average hourly sales volumes by month (average of averages), or averaging the largest two average hourly sales volume by month (third quartile of averages). Therefore, Confidential Figure 8 shows the actual historical market caps, albeit at a different scale and aggregated. It is important to note that the MWh sales data underlying Confidential Figure 8 is the actual data used to calculate market caps in this TAM and in prior TAMs.

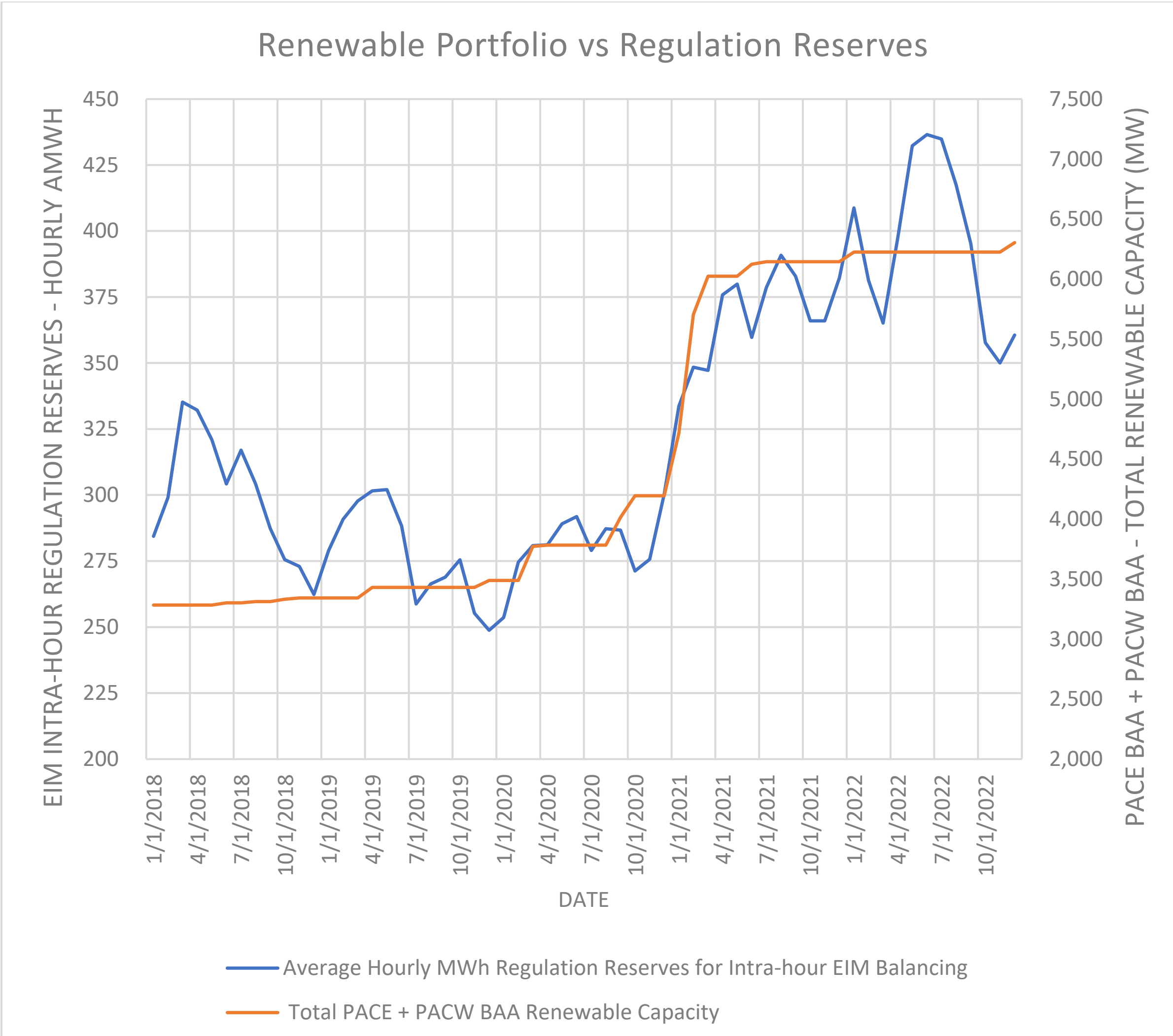
Q. Why have sales volumes been decreasing across the region, and similarly at the Company, in the day-ahead timeframe?

A. Market sales are supported by excess supply, and excess supply in this context is defined as the generation capacity remaining after all load and reserve obligations have been served. As excess supply decreases, market sales decrease. Diminishing excess supply in the region and in the Company is attributable to increased regulation reserves and the EIM.

Q. How do regulation reserves contribute to diminishing excess supply?

A. As entities across the region integrate ever increasing numbers of variable renewable resources into their portfolio, their regulation reserve obligations increase. This relationship is illustrated in Figure 9. As these reserve obligations increase, excess supply is diminished. This reduction in excess supply will naturally result in lower market sales in the day-ahead timeframe. The trend whereby variable renewable resources occupy a larger portion of entities' portfolios over time is one that will continue to increase well into and past 2024 due to various federal and state regulations.

Figure 9



Q. Are the regulation reserve numbers in Figure 9 representative of PacifiCorp's regulation reserve requirements?

A. No. These numbers are the EIM's calculation of regulation reserves using errors in load, wind and solar forecasts made approximately 45 minutes before the operating moment (real-time) as compared to forecasts made approximately 10 minutes before real-time. PacifiCorp's regulation reserve requirements, subject to NERC standards, are calculated from errors in load, wind, solar and other non-dispatchable generation forecasts made approximately 107 minutes before real-time as compared to actuals (i.e., 0 minutes before real-time). As such, the trend is comparable but not the magnitude.

Q. How does the EIM contribute to diminishing excess supply?

A. With the emergence of the EIM, which now serves nearly 80 percent[73] of the demand for electricity in the western interconnection, EIM entities face additional opportunity costs that must be contemplated in the day-ahead timeframe. If an EIM entity finds itself with excess supply and the expected price in the EIM is greater than the prevailing price in the day-ahead time frame, then the entity may forego selling their excess supply into the day-ahead markets and instead set that excess supply aside for sale in the EIM. This naturally reduces market sales in the day-ahead timeframe.

Q. What about the hour-ahead bilateral market?

A. As it concerns regulation reserves, the associated obligation exists in the day-ahead timeframe as well as in the hour-ahead timeframe. Regulation reserve obligations diminish excess supply in both timeframes. Regarding the EIM, in a counterfactual world absent the EIM, the opportunity costs associated with selling into the hour-ahead bilateral markets are still present. The EIM simply adds an additional market in which to sell excess supply and consequently, reduces both day-ahead and hour-ahead sales as compared to that counterfactual world absent the EIM.

[73] California Independent System Operator, News Release detailing *New entities expand WEIM's reach to a total of 11 Western states*, , at 1 (April 5, 2023), *available at* https://www.westerneim.com/Documents/new-entities-expand-weims-reach-to-a-total-of-11-western-states.pdf.

Q. Do regulation reserve requirements capture the entire impact of variable renewable resources on day-ahead market sales?

A. No. Regulation reserve requirements as currently calculated by PacifiCorp only reflect uncertainty for the upcoming hour, i.e., hour-ahead forecast error. The regulation reserve requirement calculations do not yet account for day-ahead forecast error and the associated uncertainty. On a day-ahead basis, there is additional uncertainty in the forecast levels of variable renewable resources that is not captured by the regulation reserve requirement. As opportunities to transact on an hour-ahead basis decline, there are fewer opportunities to compensate for changes in forecast variable renewable resource output using external resources, so utilities must maintain an additional supply of dispatchable resources (excess supply) in the day-ahead timeframe, above and beyond the hour-ahead regulation reserve requirements, in order to be assured of maintaining their load and resource balance and to meet EIM requirements. This additional day-ahead uncertainty further reduces the ability and willingness of PacifiCorp and other utilities to make day-ahead sales, impacting volumes (excess supply) available in that timeframe.

Q. Will the proposed EDAM reduce the barriers to transactions between utilities on a day-ahead and hour-ahead basis?

A. Not in the 2024 test period relevant to this proceeding; the EDAM will not be implemented until 2025. In addition, while the EDAM could significantly enhance market liquidity relative to current operations, absent the application of constraints like market caps and the DA/RT adjustment, the Aurora model with perfect foresight would reflect greater market liquidity and less market volume respectively than operations in the EDAM would reflect.

Q. What are the implications to market caps given that market sales have been diminishing year over year and are expected to continue diminishing into 2024?

A. Given the historical trend of diminishing market sales and given the market fundamentals that support the trend continuing into 2024 (variable renewable resource integration and growing EIM operational experience on the part of new entrants) it is expected that market sales will be lower in 2024 than they have been from 2019 to 2022. Setting aside the fact that this diminishing market sales trend implies that a **minimum** of averages methodology would be the most appropriate, there is certainly an overabundance of justification for use of an average of averages methodology. The third quartile of averages methodology is fundamentally flawed as it presupposes that the trend in market sales will reverse course and increase over time. This is not supported by the data.

Q. How do the 2024 market caps methodologies visually compare to the historical data?

A. Please refer to Confidential Figure 10, which shows that the market caps under either the average of averages or the third quartile of averages approach far exceed the implications of the trend in the Company's historical off-system sales volumes as illustrated in Confidential Figure 8 and are contrary to the wider markets' clear trend of declining bilateral transactions as illustrated in Figure 7.

Confidential Figure 10

[redacted]

Q. What interplay exists between market sales in Aurora and market sales in the EIM?

A. Because Aurora is an hourly model and does not contemplate the EIM, if market caps are not adjusted downwards to accommodate the market sales volumes implicit in the 2024 TAM NPC EIM benefits line item forecast, then, on a fundamental level Aurora will sell the same excess supply twice and double count benefits. The excess supply will first be sold during system balancing within the model (Aurora) and then the excess supply will again be sold within the outboard EIM benefits forecast model, which does not add sales or purchases volume into the NPC forecast (only dollars). Not only will the excess supply be sold twice and double counted, but on a more basic level, the transmission that accommodates the market sales in Aurora will no longer be available for donation to the EIM for that hour, and again, EIM export benefits will not be possible.

Q. Why is this interplay between the EIM benefits forecast model and the Aurora model relevant to NPC forecast in the 2024 TAM?

A. On a net basis, generation can only be sold once. Additionally, transmission used in Aurora for market sales is transmission unavailable for use in the forecast of EIM benefits. If the market caps are not adjusted downwards to conform with the existing diminishing market sales' trends, then either the EIM benefits forecast must be substantially reduced or the NPC forecast will, by definition, consist of a known and unresolved inaccuracy.

Q. Staff also claims that "the Company often sells far more power into these markets than the market caps allow."[74] Is this statement true?

A. It is misleading. By design, at the aggregate monthly level across the trading horizons that the market caps represent, the Company does not sell "far more power into these markets than the market caps allow" because the historical actual market caps are the sum of all monthly market sales in the day-ahead and real-time bilateral markets. Specifically, the historical market caps that are used in the calculation of the 2024 TAM NPC forecast's market cap limits are in and of themselves the total actual market sales. It is true that the Company sold more power in 2019 than the average

[74] Staff/300, Dlouhy/7.

of averages method allows for in 2024, but this is reasonable and expected given that market caps are on a consistently declining trend across the four years of history used to develop the limits. It is also true that in 2024 in a specific LLH or HLH of the day the Company could sell more power in actual operations than the market caps allow for in the NPC forecast, but that is the result of using a monthly total LLH or HLH sales volume to derive a normalized hourly limit. However, Staff does not appear to be taking a position on the use of normalization in the NPC forecasts and that is a separate discussion that involves far more impactful modeling inputs, such as the solar generation forecast, hydroelectric generation forecast, load forecast, etc. What is true is that in 2022, the Company has sold *far less* total annual power than in the 2024 NPC forecast using the **average** of averages method (let alone Staff's proposed **third quartile** of averages method, which allows for even greater sales). As set forth above, both the third quartile of averages method **and** the average of averages method produce market sales volumes that exceed the historical trend of declining sales volumes and therefore produce revenues that do not correspond to market realities.

Staff's position here—which increases market caps to drive down NPC—is particularly unreasonable given that there is little dispute that the overall NPC forecast has been significantly below actuals for years and Staff's own testimony acknowledges that the benchmark Aurora study significantly over-forecasts off-system sales. Indeed, the significant under-recovery of NPC in the 2022 PCAM is driven in substantial part by a discrepancy between the forecast of 2022 market sales and the actual 2022 market sales.

Q. How do the actual results from 2022 demonstrate the flaw in using excessive market caps set using the third quartile of averages methodology?

A. From a volume perspective, the 2022 TAM forecast [redacted] of market sales using the third quartile of averages market cap methodology. The 2022 actual market sales were only [redacted]. Had the Company used the average of averages methodology in the 2022 TAM, the forecast would have been more accurate and the requested recovery in the PCAM would be less.

Q. Staff's second argument in opposition to the Company's proposal is based on Staff's claim that there is insufficient evidence to determine whether the third quartile of averages or average of averages methodology produces a more accurate forecast in Aurora.[75] Do you agree?

A. No. As an initial matter, the market caps themselves are agnostic to the model used to forecast NPC because market caps reflect actual operations and represent the ability or willingness of entities to purchase power from PacifiCorp. Because Aurora has no internal market cap limits, just like GRID, the transition to Aurora has not diminished the need to impose realistic limits.

Moreover, there is significant evidence showing that the average of averages methodology is superior. The most straightforward way to assess the reasonableness of a market cap is to compare the historical market sales volume with the forecast market sales volume. If one model reduces or increases market sales volume relative to another, then that is a reflection on the performance of the model and irrelevant to

[75] Staff/300, Dlouhy/8.

the fact that the forecast market sales volume are reasonable or unreasonable with respect to the historical volumes.

As illustrated in Confidential Figure 11, which is a visualization of Confidential Table 5, the 2024 forecast of market sales volumes under both the third quartile of averages **and** the average of averages is above the trend demonstrated in the Company's historical sales volume; that same trend which is demonstrated at the regional level among all market participants.

Confidential Figure 11

[redacted]

Q. Staff's third argument relates to the purported relationship between the market caps and DA/RT price component.[76] How do you respond?

A. Staff's argument has no merit. Staff concedes that even if its market cap methodology overstates off-system sales revenues, the DA/RT price component understates off-system sales revenues and therefore the two adjustments are offsetting. As discussed above, Staff's argument that the DA/RT price component understates revenue ignores the arbitrage revenue that is added back into the NPC forecast through the volume component of the DA/RT adjustment. When the DA/RT adjustment is viewed holistically, both price component and volume component together, there are no artificial losses that result from the price component's adders. This fact was recognized by the Commission explicitly when it rejected Staff's similar argument in the 2017 TAM and Staff has presented nothing here to show that the DA/RT adjustment has changed in any relevant way since its argument was rejected seven years ago.

B. Reply to AWEC

Q. Please summarize AWEC's recommendation related to market caps.

A. AWEC recommends that the Commission require the use of the third quartile of averages methodology.[77] In addition, AWEC recommends that the next TAM should include a holistic examination of market caps, including an evaluation of calculating the caps using hourly data, instead of monthly data.[78]

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[76] Staff/300, Dlouhy/ 9.
[77] AWEC/100, Mullins/6.
[78] AWEC/100, Mullins/6–7.

Q. As an initial matter, AWEC claims that Aurora, unlike GRID, does not have a specific model parameter limiting the volume of off-system sales and that Aurora "lacks capability to evaluate off-system sales altogether."[79] Is this true?

A. No. The functionality that enabled GRID to evaluate off-system sales is identical in concept to the functionality that enables Aurora to evaluate off-system sales. The difference between the two models is that GRID's functionality was hidden in black-box code, whereas Aurora's functionality is modeled by the Company and visible to the parties.

Furthermore, Aurora offers more flexibility to evaluate off-system sales because, unlike GRID, Aurora's functionality is editable by the user through a graphical user interface.

Finally, the Company disagrees with AWEC's characterization of the method by which Aurora evaluates off-system sales, which AWEC describes as "modeling workarounds" because it is: (1) a modeling technique (not workaround); and (2) an accurate representation of how the market is perceived by the Company. From the Company's perspective, an electricity market *sale* at a trading hub is mostly a large pool of unspecified load which is served when the Company's generation displaces another unspecified utility's generation. That is to say, for the majority of market *sales* made by the Company, the load(s) that those market sales serve and the corresponding generator that the Company displaces is unknown at the moment of transaction. What AWEC dismissively refers to as "displacement of fictionalized

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[79] AWEC/100, Mullins/4.

loads"[80] is more accurately described as "displacement of unknown load" and is precisely what's modeled in Aurora and is appropriate. Similarly, from the Company's perspective, an electricity market *purchase* at a trading hub is essentially a large pool of unspecified generation from unknown utilities that serve the Company's load by displacing the Company's own generators. That is to say, for the majority of market purchases made by the Company, the generators from which those market purchases are sourced are unknown at the moment of transaction.

Q. AWEC also claims that Aurora "was designed to simulate a regional dispatch, not a closed system dispatch."[81] Is this true?

A. No. Aurora was designed to simulate a "closed system" regional dispatch (entities in the West often use it to simulate the "closed system" of the western interconnection).

Q. AWEC argues against market caps at Mid-Columbia and Palo Verde because it claims those hubs are highly liquid.[82] Do you agree?

A. No. Highly liquid hubs no longer exist for an electric utility that is the Company's size at the Mid-Columbia and Palo Verde markets. As demonstrated in Figure 7, the volume of transactions at the Mid-Columbia trading hub have declined, and energy shortfalls have increased across the region.[83] This exacerbation of energy shortfalls is demonstrated by the increased frequency of NERC reliability flags. The average duration of the highest level of energy emergency alerts (EEA 3) in 2022 was more

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[80] AWEC/100, Mullins/4.
[81] AWEC/100, Mullins/4.
[82] AWEC/100, Mullins/5.
[83] North American Electric Reliability Corporation, 2022 Long-Term Reliability Assessment, at 11 (Dec. 2022), *available at*-https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf.

than 200 minutes, exceeding the average duration for EEA alerts in previous years by almost double.[84]

The same trend of declining transactions is observed at Palo Verde where, interestingly enough, AWEC believes that the Company has no transmission access to in 2024. I discuss AWEC's flawed assumptions on the Company's Palo Verde transmission in Section XV of my testimony.

Q. AWEC claims, "Using an average to set a maximum level of sales has the inherent result of producing a sales value that is less than the historical average. This is the main problem with PacifiCorp's use of average market caps."[85] Is this an accurate representation of the average of averages methodology?

A. No, it is misdirection. As demonstrated above in Section VI(A), it is appropriate that the 2024 forecast of sales volumes is less than the historical average because the Company's sales volumes have been declining year-over-year for the past five years. It is demonstrated with data and irrefutable analysis that this trend in declining sales volume is both factual and driven by underlying market fundamentals that will persist into calendar year 2024. There is no upcoming change in the regional markets between now and the end of calendar year 2024 that suggests any other alternative than that the Company's **actual** operational sales volume will be less than the historical average. Attempting to produce a different result that shows higher than average sales volumes in this TAM NPC forecast of 2024 operations will be

[84] Western Electricity Coordinating Council, State of the Interconnection 2023, at 5 (Mar. 24, 2023), *available at* - https://www.wecc.org/Administrative/State%20of%20the%20Interconnection.pdf.
[85] AWEC/100, Mullins/6.

inaccurate and will produce forecasted sales revenues that do not correspond to market realities.

VII. OTR

A. Reply to Staff

Q. Please describe Staff's concern related to the Company's OTR modeling.

A. Staff is concerned that the NOx emission levels included in the Initial Filing's OTR modeling indicated that [redacted].[86] Staff testified that it was looking into the accuracy of the NOx limit assumptions and whether the Company could have exercised greater flexibility across its fleet.

Q. Has the Company addressed Staff's concern?

A. Yes. When the Company inputted the modeling parameters that governed the application of the OTR in the NPC forecast in its Initial Filing, the EPA had not finalized the rule. These modeling parameters in the Initial Filing were based on preliminary data and assumptions based on what was known at that time. These assumptions suggested that sharing NOx allowances across generating units would be detrimental to the receipt of future years' NOx allowances, which are calculated based on historical generation unit usage. This implied that NOx emissions limits should apply on a unit-by-unit basis to ensure that the Company received the greatest amount of NOx allowances allowable under the rule in future years.

[86] Staff/400, Anderson/5, 11–12.

Since the finalization and publication of the OTR in the Federal Register (which occurred after the initial modeling of the OTR in the Initial Filing), the Company no longer assumes individual NOx emission constraints on each generating unit, but instead can comply with the OTR, and ensure adequate receipt of future NOx allowances, through an aggregate fleet-wide NOx limit subject to 121 percent of each state's individual NOx limit. The Reply Update NPC forecast reflects this more refined modeling based on the final version of the OTR, which has reduced the NPC impact of the OTR by $156 million, on an isolated basis.

Furthermore, as mentioned above in Section III the Company has proposed a modeling logic refinement that will increase the generation from the coal and gas plants across its fleet, allowing for more flexibility to respond to Utah coal supply constraints.

B. Reply to AWEC

Q. Please explain AWEC's position on the Company's OTR modeling.

A. AWEC argues that the OTR will not apply to Wyoming in 2024, there is uncertainty about whether it will apply to Utah in 2024 because of ongoing litigation, and that the Company modeled OTR incorrectly because the OTR only applies to the months of May through September, while the Company modeled the limitations all year.[87] Based on these criticisms, AWEC recommends a $202 million total-company reduction in NPC to remove the impact of the OTR.[88]

[87] AWEC/100, Mullins/14–15.
[88] AWEC/100, Mullins/15.

Q. How do you respond to AWEC's adjustment?

A. As an initial matter, AWEC's adjustment is based on several misstatements of fact that should be corrected. First, AWEC misrepresents the Company's OTR modeling in the Initial Filing, which correctly models limits only during the months of May through September. This fact was made clear in both the Company's direct testimony and the Aurora model results that accompanied the Initial Filing.[89]

Second, AWEC's claim that "it is now known that the [OTR] will not apply to Wyoming"[90] in 2024 is incorrect. In fact, the EPA deferred its decision on Wyoming's plan until December 15, 2023. This means that on or after that date the EPA will decide whether Wyoming is subject to the OTR. Company witness Owen describes this element of the OTR in greater detail in his testimony.

Q. Do you agree that there is uncertainty surrounding whether the OTR will apply to Utah in 2024?

A. While I am not a lawyer, I understand that there is currently litigation related to the applicability of the OTR to Utah in 2024. However, it is my understanding that as of the date of this Reply Testimony, the OTR will apply to Utah and therefore it is reasonable to model its impact in the 2024 TAM, as discussed by Company witness Owen.

[89] *See* PAC/100, Mitchell/18.
[90] AWEC/100, Mullins/15.

Q. Given the uncertainty around OTR, does the Company have any other recommendations?

A. Yes. Because there is uncertainty, the Company recommends that the Commission include the expected OTR impact in the NPC forecast and also approve a deferral that will allow the Company to defer the actual OTR impact for later recovery or refund, similar to the approach employed in the 2023 TAM. This approach will ensure that the NPC forecast is based on the best available information at the time rates are set, while also ensuring that the Company is able to recover its prudently incurred costs for complying with federal regulations.

C. Reply to Vitesse

Q. Please explain Vitesse's OTR adjustment.

A. First, Vitesse recommends excluding the impact of OTR for Wyoming because there is uncertainty around whether the rule will apply to Wyoming in 2024 and because the Company has not demonstrated how it established and modeled the NOx limits in its NPC forecast.[91] This Wyoming OTR adjustment would reduce NPC by $9.4 million total-company.

Second, Vitesse recommends excluding the impact of the OTR for Utah because the Company provided insufficient explanation of its assumed OTR limits and modeling in its Initial Filing.[92] In particular, Vitesse criticized the Company's modeling for using "individual NOx emission constraints on each plant" rather than

[91] Vitesse/100, Johnson/29.
[92] Vitesse/100, Johnson/29–31.

complying with the OTR by "having a basket of emission allowances that [the Company] can distribute to the plants called upon to dispatch."[93]

Q. How do you respond to Vitesse's adjustment?

A. As described above, the Company's updated OTR modeling largely resolves Vitesse's concerns.

VIII. COAL UNIT MODELING

A. Reply to Staff

Q. Staff questions whether the Company has accurately forecast market purchase prices to reflect their value in providing flexibility when coal generators are constrained by insufficient supply.[94] How do you respond?

A. The Company does not forecast the underlying market prices used in the TAM NPC forecast. These market prices are determined by market data from ICE indices and third-party brokers and reflect the real market prices as traded in the real forward markets. For example, today the Company can go out into the real power market and purchase power for delivery one year from now. These types of transactions and their aggregate prices are forward transactions and forward prices respectively and the forward prices are reflected in the Company's OFPC; the Company does not forecast them.

[93] Vitesse/100, Johnson/30.
[94] Staff/400, Anderson/5.

Q. Staff also requested that the Company explain how its coal modeling addressed the possibility of additional coal provided to Hunter [redacted].[95] How did the Reply Update modeling address this issue?

A. The TAM NPC forecast estimates the receipt of [redacted] of coal provided to Hunter based on recent delivery history. Company witness Owen provides detail on the coal supply conditions at the Hunter plant in his testimony.

B. Reply to Sierra Club

Q. Please describe Sierra Club's recommendation for modeling minimum take provisions for new coal contracts.

A. Sierra Club argues that "recently executed and speculative future contracts" should be modeled in Aurora as if the contracts had no minimum take requirements.[96] Sierra Club argues that modeling a minimum take provision for these contracts means that "ratepayers cover those coal fuel expenses even if they are higher than potential alternatives at the time of generation[.]"[97]

Q. Do you agree with Sierra Club's recommendation?

A. No. Sierra Club's recommendation is contrary to Commission precedent and operational realities and would produce a less accurate NPC forecast.

Q. By way of background, what are minimum take (or take-or-pay) provisions?

A. As explained in greater detail by Company witness Owen, take-or-pay provisions provide for a minimum payment to be due if PacifiCorp fails to take the minimum

[95] Staff/400, Anderson/7–8.
[96] Sierra Club/100, Burgess and Roumpani/13.
[97] Sierra Club/100, Burgess and Roumpani/13.

contract volume. The Company pays for the full purchase price of fuel due if the annual purchases are below the minimum volume required for a certain timeframe such as a contract year.

Q. Has Sierra Club recognized that coal contracts typically include minimum take provisions?

A. Yes. As discussed in more detail in Company witness Owen's testimony, Sierra Club agrees that "some coal supply from third parties might require the inclusion of a minimum take provision as a practical matter."[98]

Q. How are minimum take provisions modeled in Aurora?

A. Within Aurora, the volume of the minimum take provision is modeled as a volumetric constraint that requires annual aggregate coal dispatch to be at or above that minimum take volume. Within Aurora's optimization, there is no price applicable to a minimum take volume under this volumetric constraint modeling. Then, after the Aurora model run, the NPC report applies the cost of the minimum take provision to the minimum take volume.

Q. Separate from Aurora, is it appropriate to price minimum take levels in the NPC report?

A. Yes. As described in further detail in Company witness Owen's testimony, minimum takes are generally a necessary part of the coal contracting process. As a result, in order to ensure an accurate forecast, it is appropriate to include the actual minimum take in a recently executed contract and the estimated level of a contractual minimum take for a yet-to-be-executed contract when modeling NPC for the test year. This

[98] Sierra Club/100, Burgess and Roumpani/14.

approach is consistent with the modeling the Commission approved in the 2022 TAM.[99]

Q. Has the Commission previously addressed Sierra Club's argument that the Company should not model minimum take requirements for new coal contracts that had not been reviewed or new coal contracts that had not been signed?

A. Yes. In the 2022 TAM, Sierra Club argued that the Company was improperly modeling minimum take requirements in the same two scenarios raised here. As described by the Commission in Order No. 21-379:

> First, PacifiCorp assumes it is bound by minimum take requirements before the contract is approved, such as at Hunter, Dave Johnston, and Craig (discussed below). Second, PacifiCorp assumes obligations when the contracts have not yet been signed for 2022. For example, the assumption that PacifiCorp will have a minimum take with Black Butte for Jim Bridger when that contract has not yet been signed.[100]

Q. Did the Commission accept Sierra Club's argument in the 2022 TAM?

A. No. The Commission approved the use of a minimum take volumes for the plants with new contracts that had yet to be approved and new contracts that had not been signed.

Q. Has PacifiCorp changed how it models minimum take provisions in this TAM?

A. No. The Company is using the same approach that was approved in the 2022 TAM.

[99] Order No. 21-379 at 11–12. In the 2022 TAM, the Commission approved the Company's modeling of minimum take provisions, which was based on the iterative process used in GRID. The transition to Aurora eliminated the need to iteratively determine a dispatch price (which was the focus of controversy in the 2022 TAM) but otherwise the Company's modeling in this case is substantively the same as that approved by the Commission.
[100] Order No. 21-379 at 11.

Q. Please explain why the use of estimated fuel costs is appropriate for modeling NPC when actual fuel costs are unavailable, for example, because a new coal contract has yet to be signed.

A. When actual fuel costs per a contract are not yet available, the use of estimated fuel costs is necessary to have a reasonable and accurate NPC forecast for setting rates in the TAM. If a coal unit does not have an executed coal supply agreement at the time of the TAM filing, PacifiCorp uses reasonable proxy fuel cost so those units can be dispatched economically to provide the optimized solution for serving customer load in the forecast while adhering to system constraints. PacifiCorp strives for a forecast that appropriately represents PacifiCorp's actual system operations within the modeling constraints. In actual operations, PacifiCorp cannot generate energy from a coal unit without paying for the fuel to generate that power. Therefore, to model an accurate dispatch price for the generation costs of that unit, PacifiCorp needs to include the fuel costs for that unit. When PacifiCorp has not finalized the contract pricing for a particular plant, the Company must use estimated pricing to develop a NPC forecast. Without including estimated costs, PacifiCorp's forecast would not reflect the operational reality of the costs of generating energy from those units. Not only is this logical, but it is also standard industry practice in order to forecast NPC in a manner that reflects operational reality. PacifiCorp has consistently used estimated costs for coal contracts when forecasting NPC in prior TAMs, including the 2022 TAM. Indeed, Sierra Club raised the same argument in the 2022 TAM, when it claimed that PacifiCorp improperly assumed it would have a "minimum take with Black Butte for Jim Bridger when that contract [had] not yet been signed."[101]

Q. Why is Sierra Club's recommendation to ignore minimum take requirements for new and anticipated coal contracts unreasonable?

A. In addition to the reasons discussed above, Sierra Club's testimony in this case improperly conflates two distinct modeling exercises—(1) the multi-year Plexos modeling that is used to evaluate minimum take volumes when negotiating new coal contracts and (2) the single-year TAM modeling using Aurora that is intended to produce an accurate NPC forecast based on expected conditions during the test year.

It is critical to assess the economics and prudence of multi-year coal contracts over the expected term of the contract (not a single year) and under different future scenarios, consistent with the analysis PacifiCorp performs and has included in the record here as exhibits to Company witness Owen's direct testimony. Moreover, when the Company performs its multi-year assessment of prospective coal contracts, it assumes no minimum take volume, consistent with Sierra Club's recommendation. Sierra Club's position is akin to arguing that the TAM is the appropriate forum for evaluating long-term resource decisions, as opposed to the IRP.

Were the Company to assume no minimum take volumes in the single year NPC forecast while simultaneously anticipating minimum take volumes to be incorporated into the actual multi-year coal contract, then the NPC modeling would be inaccurate and contrary to the best available information and disconnected from the operational constraints anticipated during the test period.

[101] Order No. 21-379 at 11.

Q. Sierra Club's testimony addressed several issues around the Company's average cost Aurora run.[102] For background, please describe the average cost run included with the TAM filing.

A. As part of the settlement of the 2021 TAM, the Company agreed to perform an informational Aurora model run, based on the initial TAM filing, that removes any operational constraints related to the minimum take provisions in the coal supply agreements and uses an average coal price for purposes of dispatching coal plants.[103]

Q. Please describe Sierra Club's concerns related to this informational filing in this case.

A. Sierra Club identified a couple of differences between the informational average cost Aurora run and the 2024 TAM Aurora run that it claims are concerning. First, Sierra Club claims that the 2024 TAM assumed a [redacted] variable fuel price for Hunter, while the average cost assumed [redacted].[104] Sierra Club is concerned that despite this price difference, the dispatched energy from Hunter was only [redacted] in the average cost run.[105] In fact, Hunter had no variable fuel price in the 2024 TAM. Given the coal supply limitations in Utah, Hunter is forecast with only a minimum quantity of coal available with no incremental flexibility. As mentioned above, within Aurora's optimization there is no price applicable to a minimum take volume under volumetric constraint modeling. With this as context, the average cost of [redacted] is instead comparable to the *implied* $/MMBtu price of the

[102] Sierra Club/100, Burgess and Roumpani/45–49.
[103] *See In the Matter of Pacificorp, dba Pacific Power, 2021 Transition Adjustment Mechanism*, Docket No. UE 375, Order No. 20-392, at 4 (Oct. 30, 2020).
[104] Sierra Club/100, Burgess and Roumpani/47.
[105] Sierra Club/100, Burgess and Roumpani/47.

minimum take volume,[106] which is also [redacted] and therefore there is no price difference and Sierra Club's concern is founded on a misunderstanding.

While I have not examined this average cost run in detail, removing a minimum volumetric restriction from the Hunter plant, all other things equal (inclusive of the $/MMBtu price as mentioned above), should result in a decrease in that plant's generation. With this as context, an observation of a [redacted] in generation does not give me cause for concern.

Second, Sierra Club is concerned that in the average cost run, Dave Johnston's output [redacted] even though it had a relatively low average coal cost.[107] However, as explained above in Section III, in the Initial Filing the Company used shadow prices within Aurora to determine the marginal costs of both coal and gas generation subject to explicit seasonal or annual constraints, which include NOx emissions constraints. Dave Johnston has one of the highest NOx emissions rates among the Company's thermal generating units and under that pricing paradigm, the optimization within Aurora imputed an in-model cost for Dave Johnston that was one of the highest among the Company's thermal generating units; contrary to Sierra Club's observations of the coal fuel cost in isolation, which is relatively low. While I have not examined this average cost run in detail, with this relatively high in-model cost it should be expected that removing a minimum volumetric restriction from the Dave Johnston plant, all other things equal, would reduce generation.

[106] Assuming generation above or equal to the minimum take which is the case in the 2024 TAM from which the Sierra Club incorrectly assumed a $0/MMBtu variable fuel price for Hunter.
[107] Sierra Club/100, Burgess and Roumpani/47.

Third, Sierra Club is concerned that the average cost run included the actual costs imposed by minimum take provisions, rather than ignoring minimum take amounts in their entirety.[108] However, the average cost run did not include the actual costs imposed by minimum take provisions within Aurora's optimization. This cost was accounted for in the NPC report. Accounting for the actual costs imposed by minimum take provisions in the NPC report is appropriate when the plant's annual aggregate dispatch falls below its annual minimum take volume because the Company will still incur the full minimum take cost and this accounting reflects reality.

Q. For future TAM filings, Sierra Club recommends several modifications to the average cost Aurora model run.[109] Do you agree with Sierra Club's recommendations?

A. No. Sierra Club's recommendations are unreasonable because they are overly burdensome and would require the Company to model entirely unrealistic scenarios, thereby producing little meaningful analysis. Moreover, Sierra Club has access to Aurora and can therefore perform its own average cost model run using whatever assumptions Sierra Club wants to use. In the alternative, Sierra Club can request that the Company perform one model run (consistent with the settlement agreement in the 2021 TAM) using Sierra Club's preferred assumptions. Given these options, there is no reason to impose additional requirements on the average cost model run that the Company provides with the initial TAM filing.

[108] Sierra Club/100, Burgess and Roumpani/47–48.
[109] Sierra Club/100, Burgess and Roumpani/48–49.

IX. WASHINGTON CAP AND INVEST PROGRAM

Q. Please describe the Washington Cap and Invest Program.

A. Generally, the Company is required to purchase GHG allowances for emissions from plants located in Washington that export power outside of the state. For PacifiCorp, this impacts the generation from the Chehalis plant. As explained in the Company's direct testimony, the Washington Cap and Invest Program is functionally the same as the EIM GHG costs and benefits resulting from California's Cap and Trade programs and the Wyoming wind tax.[110]

In addition, as discussed in Company witness Zepure Shahumyan's reply testimony, the Washington Cap and Invest Program provides no-cost allowances to mitigate the cost burden of the law on Washington retail customers.

A. Reply to Staff

Q. Please describe Staff's recommendation related to the Company's modeling of the Washington Cap and Invest Program.

A. Staff criticizes the Company for allocating the no-cost Washington Cap and Invest Program allowances only to Washington customers because Staff infers that there is no requirement that PacifiCorp do so.[111] Staff therefore recommends a $1.65 million reduction in NPC to allocate a portion of the no-cost allowances to Oregon using the System Generation (SG) allocation factor.[112]

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[110] PAC/100, Mitchell/21.
[111] Staff/400, Anderson/13.
[112] Staff/400, Anderson/13–14.

Q. How do you respond?

A. The Company's modeling of the no-cost allowances is reasonable and in accordance with direction provide by the Washington State Department of Ecology, as discussed by Company witness Shahumyan. Staff's adjustment should therefore be rejected.

Q. Staff also testifies that even if no-cost allowances must be allocated to Washington customers, it is "fair and equitable" to also allocate them to Oregon customers using the SG allocation factor.[113] How do you respond?

A. Staff's argument begins by stating that "it does not appear" that the Company is obligated to allocate the no-cost allowances to Washington customers due to the requirement of Washington law. However, Staff further argues that, regardless of the law, the Company should also allocate a portion of these no-cost allowances to Oregon customers, potentially resulting in a violation of Washington law. As I am not a legal expert, I refrain from commenting on Staff's proposal, which may necessitate that this Commission order the Company to violate direction received from another state agency. However, it is essential to emphasize that the Company is legally bound to comply with all applicable laws, including both Oregon and Washington law, which encompasses the Cap and Invest Program. If the Commission were to issue an order contradicting these legal obligations, it would place the Company in an untenable situation.

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[113] Staff/400, Anderson/14.

Q. Staff claims that if Oregon customers do not receive a portion of the no-cost allowances, then "it [would] appear that Washington is exporting the costs of its energy policies to other states while protecting Washington customers from such costs."[114] How do you respond?

A. First, the fact that Washington has chosen to subsidize its own customers does not mean that Oregon is entitled to take those subsidies for itself.

Second, the treatment of the Washington Cap and Invest Program is functionally no different from the impact of California's Cap and Trade program or the Wyoming wind tax, or a number of other taxes that I refer to below, all of which reflect other states' policies that impact the costs and benefits received by Oregon customers. The costs associated with the Washington Cap and Invest Program represent incremental and actual costs of generating at the Chehalis plant and if that plant is used to serve Oregon customers, then Oregon customers should pay their share of the costs.

Third, as referenced above, there are other taxes resulting from other states' policies that are, and have been for years, incorporated into the TAM NPC forecast. Examples of these above and beyond Wyoming's wind tax are: (1) state coal fuel taxes that are embedded into the NPC forecast's coal prices; and (2) state natural gas fuel taxes for natural gas supply and transportation that are embedded into the NPC forecast's gas prices.

[114] Staff/400, Anderson/14.

B. Reply to AWEC

Q. Please describe AWEC's recommendation related to the Washington Cap and Invest Program.

A. AWEC argues that the Washington Cap and Invest Program created "[c]omplex legal issues. . . with respect to the imposition of generation taxes and regulations that impact interstate commerce" and therefore the costs are not permissible in the TAM.[115] AWEC therefore recommends removing all costs related to the Washington Cap and Invest Program.

Q. Do you agree?

A. No. I am not a lawyer and will not discuss the purported legal issues alluded to by AWEC. However, as noted above, the Washington Cap and Invest Program costs are functionally the same as the California Cap and Trade program, the Wyoming wind tax, and various other taxes, which have been accounted for in the TAM for years without issue. If Oregon customers are served by the Chehalis plant, then it is reasonable for Oregon customers to pay the actual costs incurred to generate at the Chehalis plant, including the costs of GHG emissions allowances required by Washington law. AWEC's argument would provide Oregon customers with the benefits of Chehalis while relieving them of the costs incurred to produce those benefits.

[115] AWEC/100, Mullins/12.

Q. AWEC tries to distinguish between the Washington Cap and Invest Program and the Wyoming wind tax by arguing that the Washington program is higher cost.[116] Is that a legitimate basis to exclude the costs of the Washington Cap and Invest Program from the TAM?

A. No. The fact that the Washington Cap and Invest Program costs are higher than the Wyoming wind tax does not have any bearing on whether it is reasonable to allocate both costs to Oregon customers in the TAM.

Q. Is AWEC's position here consistent with the position it has taken in other proceedings?

A. No. In Portland General Electric Company's (PGE) current annual update tariff (AUT), docket UE 416, AWEC witness Mullins submitted testimony related to PGE's modeling of the Washington Cap and Invest Program.[117] In PGE's case, AWEC (1) did not argue that the Washington Cap and Invest Program is unlawful; (2) did not argue that the costs of the Washington Cap and Invest Program are impermissible to include in the AUT; and (3) did not argue that the Washington Cap and Invest Program costs improperly imposed Washington state policies on Oregon customers. On the contrary, AWEC recommended an adjustment purporting to specifically *include* the benefits of the Washington Cap and Invest Program as a reduction to forecast NPC. In other words, here AWEC recommends removing all costs of the Washington Cap and Invest Program while in PGE's case AWEC recommends including all benefits of the Washington Cap and Invest Program.

[116] AWEC/100, Mullins/13.
[117] *In the Matter of Portland General Electric Company, Request for a General Rate Revision; and 2024 Annual Power Cost Update*, Docket No. UE 416, AWEC/100, Mullins/13–17 (May 24, 2023).

AWEC's contradictory positions here and in PGE's AUT undermine the credibility of its recommendation.

C. Reply to Vitesse

Q. Please describe Vitesse's adjustment related to the Washington Cap and Invest Program.

A. Vitesse proposes to model the emissions profile of the Chehalis plant across its operating range instead of using a flat dollar-per-megawatt-hour ($/MWh) adder because the plant's emission intensity varies over its output range.[118]

Q. How do you respond to this recommendation?

A. Vitesse's recommendation ignores the fact that the EIM only accepts the cost of emissions in flat $/MWh amounts and as such the Company's internal operational optimization models in the day-ahead and hour-ahead timeframe conform to this standard imposed by the EIM (which to date has delivered $620 million[119] worth of savings (total-company) to the Company's customers). Vitesse's proposal attempts to introduce efficiency into the forecast of NPC that does not exist in the real world. This, by definition, diminishes the accuracy of the NPC forecast.

Q. How does the EIM's requirement to use a flat $/MWh adder for GHG costs impact the Company's operations in the day-ahead and other forward time horizons?

A. The EIM controls the final economic dispatch of Chehalis and the EIM's optimization uses a flat $/MWh to represent GHG costs. If the Company were to model the

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[118] Vitesse/100, Johnson/24.
[119] Western Energy Imbalance Market, Quarterly Benefits Report, (May 31, 2023), *available at* https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx.

emissions profile of the Chehalis plant across its operating range in its internal operational optimization models, then the *assumptions* supporting the least cost dispatch results in the day-ahead and other forward timeframes would be out of alignment with the *results* of the actual least cost dispatch and this discrepancy will create an inefficiency and associated cost that is expected to increase NPC.

X. WIND GENERATION

Q. Please describe the changes the Company made to its wind generation forecasts for the 2024 TAM.

A. The Company updated its forecast modeling to capture the negative dispatch costs of production tax credits (PTC) benefits that the GRID model was incapable of calculating.[120] As indicated in my direct testimony, initial comparison with 2022 actuals under this new methodology shows more accurate results.[121]

Q. Please describe Staff's concerns regarding the Company's wind generation forecast.

A. Staff compared actual wind generation to previous TAM forecasts for the years 2017 to 2022 and concluded that the Company historically over-forecast wind generation.[122] Staff notes that the Company acknowledges its history of over-forecasting wind generation and that the Company has followed Commission guidance to improve modeling to avoid over-forecasts.[123] However, Staff generally concludes that the Company has not provided enough information regarding its improved forecast modeling for Staff to be convinced the model is, in fact, producing

[120] PAC/100, Mitchell/25.
[121] PAC/100, Mitchell/42.
[122] Staff/600, Chipanera/2–3.
[123] Staff/600, Chipanera/3.

more accurate forecasts.[124] As a result, Staff introduces its own forecast methodology that it maintains will result in more accurate generation forecasts.[125]

Q. Please explain Staff's proposed forecast method.

A. Instead of using the Company's approach, Staff proposes that the Company average actual generation figures for the four-years prior to any filing for each of its wind facilities, provided those facilities have at least four full years of operating history.[126] For any facilities with less than four years of operating history, Staff proposes using the Company's unadjusted forecast from this year's TAM filing.[127] Staff also proposes an adjustment to the net capacity factor for Foote Creek II, III, and IV based on the settlement in the Company's RAC filing.[128]

In applying its proposed methodology, Staff indicated that it used actual generation data for three past years, 2020 to 2023, and excepted 2019 due to a substation fire that Staff claims resulted in lower wind production.[129] Staff averaged these historical generation figures to create a prediction for the upcoming year's generation and adjusted the PTC rate for inflation.[130]

Q. How do you respond to Staff's proposal?

A. As an initial matter, while Staff's updated methodology is intended to curb over-forecasting, application of its proposed methodology *increases* the Company's forecast wind generation. In fact, applying Staff's approach results [redacted]

[124] Staff/600, Chipanera/3–4.
[125] Staff/600, Chipanera/3–4.
[126] Staff/600, Chipanera/3.
[127] Staff/600, Chipanera/4.
[128] Staff/600, Chipanera/4.
[129] Staff/600, Chipanera/4.
[130] Staff/600, Chipanera/5.

[redacted][131] to the Company's forecast.[132] As such, Staff's proposal appears to run counter to Staff's position that the Company has a history of forecasting higher wind generation than actual results.

Q. Are there any assumptions in Staff's analysis that should be corrected?

A. Yes. First, Staff indicated that it removed 2019 data from its four-year average due to a substation fire that limited wind generation.[133] However, the substation fire that Staff refers to occurred in 2021. Therefore, Staff's analysis removed the wrong year.

Second, Staff's use of four-year historical averages failed to account for repowering. Indeed, each wind facility selected and modeled by Staff lacks four-year generation data, because the facilities are either new or have been repowered during the past three years. When a wind facility is repowered with new turbines, the historical generation of the older, replaced, turbines is not predictive of future generation. As a result, historical generation data from these repowered facilities is an inappropriate metric to use to forecast future generation.

Q. How would applying Staff's methodology, as corrected to account for repowering, impact the wind generation forecast in this case?

A. Staff's recommendation is that any facility with less than four years of historical generation data should continue to use the Company's proposed forecast submitted in its Initial Filing.[134] Because each relevant facility has been repowered within the past four-year period, each facility in the forecast has less than four-years of full operating

[131] This figure represents total MWh added to the Company's forecast, [redacted] MWh can be attributed to Foote Creek II, III, and IV.
[132] Staff/600, Chipanera/5.
[133] Staff/600, Chipanera/4.
[134] Staff/600, Chipanera/4.

history. As such, even if the Company were to adopt Staff's proposal, the Company would revert to using its unadjusted forecast as presented in the Initial Filing, resulting in no change to the Company's forecast.

XI. JIM BRIDGER GAS CONVERSION

Q. Please describe Staff's concerns regarding the gas conversion of Jim Bridger Units 1 and 2.

A. Staff questions the high capacity factors for the converted Jim Bridger Units 1 and 2 and is looking into whether the Company could take other steps in the forecast, such as increasing market purchases or increasing coal generation from other units to make up for the Utah coal supply issues and limit generation from the gas-converted units.[135]

Q. How do you respond to this concern?

A. The steps that Staff refers to have already taken place. Aurora models the operation of the Company's entire system and includes market purchases and dispatch of generating units, inclusive of coal. All Utah coal supply issues modeled in Aurora are accounted for within the optimization's least cost dispatch and the NPC forecast that results will increase market purchases, increase coal generation from other units and perform other actions, all of which will make up for the Utah coal supply issues. This is inclusive of limiting generation from the gas-converted Jim Bridger units when it is economic and optimal to do so. Staff's concern is by definition addressed by the use of an industry standard production cost model to forecast NPC.

135 Staff/400, Anderson/11.

Q. Staff also expressed a concern that the "[redacted]."[136] What is the source of the apparent increase?

A. Staff compared the emissions expected for the gas-converted units to the counterfactual where the units remain coal-fired units. Staff's testimony, however, did not acknowledge that in the counterfactual where the units continued to burn coal, the units also included selective catalytic reduction systems (SCR), in accordance with the EPA's requirement that the units install a SCR or cease coal-fired operations in 2023. In the counterfactual assuming continued coal-fired generation, the NOx emissions are significantly lower because of the SCR, [redacted]. The apparent increase in NOx emissions is therefore not unexpected given the assumptions in the counterfactual.

Q. Staff further recommends that the Company explain what can be done to reduce the heat rates at the gas-converted Jim Bridger Units 1 and 2.[137] What is the basis for Staff's recommendation?

A. Staff compared the expected heats rates for Jim Bridger Units 1 and 2 after they are converted to gas to the heat rates at other gas plants. Staff also compared the expected gas-converted heat rates to generic Energy Information Administration (EIA) data.

[136] Staff/400, Anderson/10.
[137] Staff/200, Jent/15.

Q. Why are the expected heat rates at Jim Bridger Units 1 and 2 higher than many other gas plants in the Company's fleet?

A. When the Jim Bridger units are converted from coal-fired to gas-fired, the units will still generate electricity in the same general way, i.e., the units will burn natural gas to boil water to generate steam that will then power steam turbines. The only difference is the heat source will be natural gas, instead of coal. This contrasts with combined cycle combustion turbine (CCCT) generating units that burn gas to directly power a combustion turbine, similar in principle to a jet engine, and then indirectly power a steam turbine using the exhaust of the combustion turbine. Generators like the converted Jim Bridger Units 1 and 2 will be less efficient (i.e., the units will have a higher heat rate) than CCCT units. This is evident by examining Staff's Confidential Figure 2, where the steam-generating gas-converted units (Gadsby 1, 2,3 and Naughton 3),[138] all have heat rates that are comparable to the gas-converted units at Jim Bridger.

Moreover, Staff's comparison of the gas-converted units to generic heat rate data for gas generation from the EIA likely suffers from the same flaw because the EIA data presumably includes all types of gas units, including more efficient CCCTs. Based on the EIA's reported value, it is highly unlikely that the heat rate data is limited to only steam-generating gas-converted units like Jim Bridger Units 1 and 2 will be.

[138] Staff incorrectly states that the Naughton 3 gas-fired unit has a 0 heat rate for the 2024 forecast, which would imply it was not producing energy. Staff/200, Jent/15. However, this is demonstrably not the case since the unit is producing energy in the NPC forecast and associated NPC report that outlines the Company's NPC proposal. In that NPC report the average heat rate of Naughton 3 is shown to be [redacted].

Q. Despite Staff's concern, does Staff acknowledge that the gas-converted units are less efficient?

A. Yes. In Staff/400, Staff acknowledges that the heat rates for the gas-converted Jim Bridger units will be inefficient compared to the more efficient CCCT units.[139]

XII. OVERALL NPC FORECAST VALIDATION

Q. How did the Company assess the overall reasonableness of the NPC forecast in the Initial Filing?

A. The Company determined that the total-company NPC forecast in the Initial Filing was reasonable based on historical trend analysis of Company NPC relative to regional power market prices extrapolated based on the forward market prices in 2024.[140] The Company then added in the impacts of operational changes that will increase NPC in 2024 but that are not reflected in the historical relationship between overall NPC and forward market prices.

Q. Does any party dispute the relationship between market prices and the Company's overall NPC?

A. Yes. Staff claims that the Company's extrapolation looked at only two market hubs—Mid-Columbia and Palo Verde—even though the Company has access to other hubs as well and that "PacifiCorp simply uses the correlation that it found between Total Company NPC and Market prices to find a hypothetical spot on its line for the year 2024."[141]

[139] Staff/400, Anderson/10.
[140] PAC/100, Mitchell/10.
[141] Staff/200, Jent/21.

Q. How do you respond to Staff's criticism?

A. First, the Company used Mid-Columbia and Palo Verde because those are representative market hubs, one for PacifiCorp West and one for PacifiCorp East. Staff did not provide any evidence that including additional market hubs would have provided any incrementally meaningful insight.

Second, Staff oversimplifies and misrepresents the Company's analysis when it testifies that the Company simply "found a hypothetical spot on a line" to analyze the 2024 forecast NPC relative to the 2024 forward market prices. In fact, the Company took 36 months of data showing the relationship between historical market prices on a $/MWh basis and historical NPC on a $/MWh basis to conduct a linear regression at the monthly granularity. This linear regression was found to be statistically significant and as a result used to forecast for future NPC on a $/MWh basis based on the OFPC's projected monthly 2024 market prices on a $/MWh basis. The resulting forecast of future NPC on a $/MWh basis was then multiplied by the monthly 2024 load projections to arrive at a forecast of NPC in total dollars. The results of the linear regression were then compared generally to the forecast NPC using Aurora to assess the overall reasonableness of the 2024 forecast. Notably, Staff did not dispute any of the Company's actual analysis or question the accuracy of the linear regression.

Q. Did Staff have any concerns about the second step in the Company's analysis, which accounted for operational changes in 2024 that were not present in the historical data?

A. Yes. Staff testifies that, "PacifiCorp states that the 2024 forecast looks large because it is considering modeling changes that were not included in the 2023 forecast. Staff wants to reiterate that each TAM gives parties a chance to propose modeling changes and using that as justification for the current forecast does not hold water."[142]

Q. How do you respond to this claim?

A. Staff misunderstands the Company's testimony, which focused on *operational and policy* changes, not *modeling* changes. In fact, the Company explained that the extrapolation based on market prices (discussed above) did not include the impacts of operational or policy changes—including the Washington Cap and Invest Program, OTR, Jim Bridger gas conversions, removal of the Klamath dams and Utah coal constraints—because these operational changes are not present in the historical data used to perform the linear regression.[143] Therefore, to fully assess the reasonableness of the 2024 forecast, the impact of these operational changes would need to be added to the estimate created by the linear regression.

The Company also explained that because the 2023 TAM NPC forecast did not include the impacts of the operational changes present in the 2024 TAM NPC forecast, then it is inappropriate to directly compare the 2023 TAM NPC forecast to the 2024 TAM NPC forecast, which includes the operational changes. As a

[142] Staff/200, Jent/21.
[143] See PAC/100, Mitchell/13–14.

consequence, for comparison purposes, the Company reintroduced the operational changes into the 2023 TAM NPC forecast to allow for meaningful comparison to the 2024 forecast.[144]

Q. Did Staff have any other concerns with the Company's overall NPC validation?

A. Yes. Staff also claims that the Company pointed to the Washington Cap and Invest Program and OTR as a reason for the NPC increase in this case but according to Staff "there were no costs associated with the Washington Cap and Invest Program and the Ozone Transport Rule in 2023, so it is inappropriate to include them in a comparison between the 2023 and 2024 forecast."[145]

Q. How do you respond?

A. The Company agrees that one cannot directly compare the 2023 and 2024 NPC forecast because the 2024 forecast in the Initial Filing included the Washington Cap and Invest Program and OTR costs, which were excluded from the 2023 forecast. However, as explained above, the Company reintroduced the Washington Cap and Invest Program and OTR into the 2023 TAM NPC forecast solely to enable an apples-to-apples comparison of the 2023 and 2024 TAM NPC forecasts, i.e., to include the impact of these new regulations to show how the NPC forecast changed by accounting for these and other operational changes occurring in 2024 that did not impact the 2023 TAM NPC forecast.[146]

Furthermore, there **are** present and potential costs in 2023 associated with the Washington Cap and Invest Program and the OTR. The Washington Cap and Invest

[144] PAC/100, Mitchell/10.
[145] Staff/200, Jent/23.
[146] PAC/100, Mitchell/10.

Program began in January 2023 and the Company is currently incurring costs because of it. The OTR which was scheduled to begin in May 2023 is now finalized and will have a delayed start in August 2023 at which point the Company may incur costs from it.

Q. The Company also explained that the 2023 NPC forecast was low because the hedges in the 2023 TAM NPC forecast were favorable to the current calendar year 2023 market prices from the OFPC used in this filing and that this indicated that the 2023 TAM NPC forecast was lower than it would have been had the hedges shown neither an economic benefit nor cost.[147] Does Staff address this argument?

A. Yes. Staff claims that the Company "wants to assume there are neither economic benefits nor costs from hedging transactions, which is not true."[148] As the Company explained in its Initial Filing, when hedges lower NPC, it is coincidental, not a guaranteed outcome or foregone conclusion because hedges are not economic optimization transactions where the Company is trying to "beat the market."[149] The Company's position here is consistent with prior filings where it has consistently argued that hedging has no systematic benefits or costs.[150] Staff does not engage at all with the Company's testimony and appears to argue that hedges should produce systematic economic benefits for customers. Staff produced no evidence for this far-reaching argument.

[147] PAC/100, Mitchell/9.
[148] Staff/200, Jent/23.
[149] PAC/100, Mitchell/9.
[150] *See, e.g.*, Order No. 17-444, at 7 ("PacifiCorp states that there are no systematic costs or benefits from hedging transactions, as hedges are a cost in some years and a benefit in others").

Q. Staff accuses the Company of "obfuscat[ing] what the actual cost contributors are by having multiple discussions that seemingly contradict one another or providing different evidence on what those cost contributors are."[151] Is this a fair criticism?

A. No. The Company's testimony was very clear that the cost drivers increasing NPC in the 2024 TAM relative to the NPC forecast in the 2023 TAM are (1) changed market prices; (2) the impact of the Washington Cap and Invest Program and the OTR; (3) the favorable 2023 hedges, which served to decrease the 2023 TAM NPC forecast; (4) increased load; and (5) the Jim Bridger gas conversion and Klamath dam removals.[152] Staff's testimony appears to misunderstand the Company's analysis, but that does not mean that the Company was obfuscating the actual cost drivers.

XIII. AURORA MODEL VALIDATION

A. Reply to Staff

Q. Staff is concerned that the Company's Aurora model validation based on 2019 data may be flawed.[153] Please describe the Company's validation process.

A. As required by the 2023 TAM settlement, the Company provided a benchmark study using actual results from 2019 to validate the accuracy of the Aurora model.

Q. Please describe Staff's concern.

A. As an initial matter, Staff testifies that for most cost categories, Aurora accurately predicted actual values within a margin of error.[154] However, Staff is concerned that

[151] Staff/200, Jent/24.
[152] PAC/100, Mitchell/7–10.
[153] Staff/200, Jent/30.
[154] Staff/200, Jent/27.

the 2019 actual results that the Company used to compare to the Aurora model results are different from the 2019 PCAM values.[155]

Q. How do you respond to Staff's concern?

A. The Company's benchmark study compared Aurora's model results to actual 2019 NPC. Actual NPC is not the same as the *adjusted* NPC in the PCAM, primarily because Oregon is not allocated the NPC benefits of the Rolling Hills wind resource, along with other state specific adjustments. It is therefore not surprising that there is a difference between the Aurora results and the PCAM results.

Q. Staff also testifies that they are "working to gain access and familiarity with the AURORA Model."[156] How do you respond to this testimony?

A. The Company has worked diligently with Staff to ensure both access to and an understanding of Aurora. Indeed, elsewhere in Staff's testimony, other Staff witnesses explain that they have access to and have run the Aurora model as support for Staff's market cap adjustment[157] and used the Aurora archive to assess the Company's coal contracts.[158]

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[155] Staff/200, Jent/30.
[156] Staff/200, Jent/31.
[157] Staff/300, Dlouhy/10.
[158] Staff/400, Anderson/5.

B. Reply to AWEC

Q. AWEC recommends that the Company use a more current version of Aurora to determine the NPC forecast.[159] Has the Company addressed this recommendation?

A. Yes. The Company used Aurora version 14.2.1059, which was the most recent, stable, version publicly available no later than one month before the time of the Reply Update.

XIV. QF FORECAST

Q. Please describe how the Company determines the QF costs included in the TAM forecast.

A. The Company uses a 48-month normalization based on historical data (for those QFs that have enough history) to create a forecast for the upcoming year. The Company then applies the Contract Delay Rate to that forecast. The forecast under this new (as of the 2023 TAM) methodology is yet to be compared to actual 2023 results but regardless, although the old method produced a modest over-forecast of QF generation it remains one of the most accurate components of the overall NPC forecast.

Q. Please describe Staff's concerns related to the QF forecast.

A. Staff contends that the Company over-forecasts QF generation and therefore Staff recommends that the Company provide updated QF forecast error percentages when submitting later TAM filings.[160]

[159] AWEC/100, Mullins/3.
[160] Staff 500, Bolton/5.

Q. How does the Company respond to this recommendation?

A. Staff's fixation on QF forecasting is perplexing given that the QF forecast is relatively accurate, particularly when compared to the significant and persistent under-forecasting of overall NPC. While the Company is working to constantly improve its forecasting models, Staff's emphasis on the over-forecast as to QF power costs is misplaced. As I explained in detail in my Reply Testimony for the 2023 TAM,[161] the aggregate QF forecast error percentage is substantially lower in magnitude than the total-company NPC forecast error percentage, substantially lower in magnitude than the sales volumes forecast error percentage, and substantially lower in magnitude than the total generation forecast error percentage as tabulated and updated in Confidential Table 6. When examined in isolation, QFs may appear to have a high forecast error percentage. However, when examined within the context of wholesale sales, other sources of generation and within the overall context of NPC it becomes apparent that the QF forecasts are relatively accurate and the least in need of improvement.

Notwithstanding the accuracy of the QF forecast, the Company does not oppose continuing to update the forecast and actual generation figures in future TAMs.

[161] *In the Matter of Pacificorp, dba Pacific Power, Transition Adjustment Mechanism*, Docket No. UE 400, PAC/600, Mitchell/61 (Sept. 1, 2022).

Confidential Table 6

Difference between Forecast and Actuals (%)				
	QFs (MWh)	Wholesale Sales (MWh)	Total Generation (MWh)	NPC ($)
Year	Percent	Percent	Percent	Percent
2018	[redacted]	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]	[redacted]
Average	[redacted]	[redacted]	[redacted]	[redacted]

Q. Does Staff have any other comments?

A. Yes. Staff noted that it previously proposed a pass-through mechanism that would allow dollar-for-dollar recovery of QF costs and implies that it may make a similar recommendation in a future rate case.[162]

Q. Do you have any response to these comments?

A. The Company has long sought dollar-for-dollar recovery of all NPC through the PCAM and generally welcomes Staff's support for a pass-through mechanism.[163] However, Staff's proposal is unreasonably narrow because it isolates a single component of NPC—and one that is relatively accurate—for dollar-for-dollar recovery. Staff's proposal is also unreasonably one-sided because it focuses on a single cost that has been historically over-forecast, while ignoring that overall NPC has been historically under-forecast.

[162] Staff/500, Bolton/3–4.

[163] *See e.g., In the Matter of Pacificorp, dba Pacific Power, Transition Adjustment Mechanism*, Docket No. UE 399, PAC/2600, Wilding/11 (Sept. 4, 2022).

XV. ARIZONA PUBLIC SERVICE (APS) SHORT TERM TRANSMISSION

Q. Please describe AWEC's adjustment related to the Company's acquisition of short-term firm transmission rights from APS to allow access to the Palo Verde market hub.

A. AWEC recommends that the Company remove all short-term firm wheeling expenses from APS and all short-term transmission capacity from Palo Verde, which reduces NPC by $7.9 million total-company.[164] AWEC argues that since the closure of the Cholla plant and the expiration of the Public Service Company of Colorado (PSCo) exchange agreement, the Company is unlikely to acquire short-term firm transmission enabling access to Palo Verde in 2024.[165]

Q. Is there any merit to AWEC's Palo Verde transmission adjustment?

A. No. The PSCo exchange agreement became effective on January 1, 2015 and expired on October 31, 2022 yet, post-expiration, the Company still actively transacts at the Palo Verde market and still actively purchases short-term transmission to enable access to the Palo Verde market. Confidential Figure 12 presents over four years of historical Palo Verde transaction data and Confidential Figure 13 presents over four years of historical Palo Verde wheeling expense. The data clearly demonstrate that the Company is still actively transacting at Palo Verde contrary to AWEC's claim.

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[164] AWEC/100, Mullins/10.
[165] AWEC/100, Mullins/10.

Confidential Figure 12

[redacted]

Confidential Figure 13

[redacted]

Q. AWEC also raises a larger concern over how Aurora models transmission. Can you describe AWEC's concern?

A. Yes. AWEC conducted an in-model analysis that removed all transmission capacity that enabled the movement of energy to and from the Palo Verde market (i.e., AWEC removed all transmission that allows for sales from the Company's system at Palo Verde and for purchases into the Company's system at Palo Verde).[166] AWEC found that removing the transmission capacity reduced NPC by $45,740 total-company and

[166] AWEC/100, Mullins/11.

therefore concluded that the "result is unintuitive and an indication that the modeling approach PacifiCorp developed is sub-optimal."[167]

Q. How do you respond to this concern?

A. AWEC's analysis is based on three crucial errors, each of which in isolation undermines AWEC's claim that Aurora produces unintuitive results.

Q. What is AWEC's first error?

A. When assessing the NPC impact of a changed input to determine if the results *in* the model are optimal, one needs to remove all *out*-of-model adjustments before one can assess the optimality of the model itself. Using AWEC's workpapers, the Company removed all out-of-model adjustments and found that from the isolated perspective of Aurora, removing the transmission capacity increased NPC by $1.8 million total-company, which is the result AWEC expected and therefore is not unintuitive.

Q. What is AWEC's second error?

A. AWEC fails to take note of the difference between NPC as defined in the TAM and all variable power costs incurred in system operations (and therefore modeled in Aurora). Because of this difference, a portion of costs modeled in Aurora are not reported in the TAM NPC, which are a subset of certain predefined Federal Energy Regulatory Commission accounts and do not contain the entirety of the system's variable power costs. As an example, portions of variable operations, maintenance and startup costs, such as coal fuel startup costs, thermal unit maintenance costs per start and thermal unit online, per hour, operating costs, are not reflected in the TAM NPC. As a result of the above-mentioned variable power costs that are excluded from

[167] AWEC/100, Mullins/11.

the TAM NPC, TAM NPC impacts may not always seem "intuitive" when considering that TAM NPC impacts are analyzing a change in only a subset of all system variable power costs. Any change in variable power costs that are outside of the subset that is the TAM NPC can show results that *appear* unintuitive but still accurately reflect the *TAM NPC* impact.

Q. What is AWEC's third error?

A. Aurora's optimization techniques leverage "Gurobi," which is a state-of-the-art commercial optimization software suite. Within Aurora's unit commitment process, Gurobi's mixed integer program is utilized to develop the least-cost (optimal) solution. However, there is an industry-wide problem known as the "unit commitment problem,"[168] which under current state of the art optimization techniques, only guarantees optimality within a certain threshold. As quoted from Gurobi documentation, sometimes Gurobi "reports a solution that may not be the optimal solution. In this case, we say the [reported] solution is ε-suboptimal, as the objective value it attains is at most ε (e.g. 0.01%) worse from the value attained by other solutions that could be found if we continue to explore the [set of possible solutions] (although there's no guarantee that such solutions exist."[169] Put simply, small NPC impacts are simply noise in the multi-billion-dollar NPC forecast and this noise results from that within-threshold-optimality.

With this as context, AWEC is incorrect in asserting that the "issue surrounding the Palo Verde market may be indicative of a more significant flaw in the

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[168] Luis Montero, et al., *A Review on the Unit Commitment Problem: Approaches, Techniques, and Resolution Methods*, 15 ENERGIES 1296 (Feb 10, 2022), *available at* https://www.mdpi.com/1996-1073/15/4/1296.
[169] Gurobi Optimization, *What is the MIPGap?* (May 2023), *available at* https://support.gurobi.com/hc/en-us/articles/8265539575953-What-is-the-MIPGap-.

AURORA model workarounds that PacifiCorp has adopted to simulate a closed-system dispatch."[170] AWEC's analysis is incomplete and fails to take into account: (1) the difference between in-model results and out-model results, (2) the difference between NPC and all variable power costs; and (3) the mathematical optimization techniques used by Aurora. Furthermore, as I explain above in Section VI(B), AWEC is also: (1) incorrect in asserting that Aurora "was designed to simulate a regional dispatch, not a closed system dispatch."[171]; and (2) incorrect in asserting that the Company therefore deploys "workarounds" to simulate a closed-system dispatch.

XVI. EIM MODELING

Q. Please describe Vitesse's proposed adjustment to the Company's EIM modeling.

A. Vitesse recommends that the Company modify the calculation of the escalation rate for EIM GHG benefits to use the growth in the forecast California Air Resources Board GHG allowance market price as the growth factor instead of the California Carbon Allowance growth factor.[172]

Q. How do you respond?

A. Vitesse's approach is reasonable for forecasting the EIM GHG benefits and the Company proposes to adopt it.

[170] AWEC/100, Mullins/11.
[171] AWEC/100, Mullins/4.
[172] Vitesse/100, Johnson/19.

XVII. EDAM

Q. Sierra Club provides several recommendations regarding oversight of PacifiCorp's participation in the EDAM.[173] How do you respond to these recommendations?

A. Sierra Club's EDAM recommendations are far beyond the scope of the 2024 TAM. The 2024 TAM does not include any of the costs or benefits of EDAM participation, which is scheduled for implementation in 2025, and therefore Sierra Club's proposals are irrelevant.

XVIII. AWEC ADJUSTMENT TO 2024 PTC RATE

Q. Please summarize AWEC's opening testimony regarding the 2024 PTC rate.

A. AWEC correctly identifies that the 2024 inflation adjustment factor must be 1.9667 or greater in order for the PTC rate to reach 3.0 cents per kilowatt hour in 2024. This represents an increase of slightly more than 4.0 percent over the 2023 inflation adjustment factor of 1.8909. Based on my conversations with our tax experts, only twice in the past 30 years has the inflation adjustment factor grown by more than 4.0 percent.

Q. Has AWEC entered evidence that this inflation adjustment factor will grow by more than 4.0 percent in 2023?

A. No. AWEC haphazardly references a Consumer Price Index and makes a casual observation that, "Given recent indications, it is likely that inflation will exceed this level for the remainder of the year," without citing what those recent indications are.

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[173] Sierra Club/100, Burgess and Roumpani/44.

Q. What is PacifiCorp's proposal for establishing the PTC rate for this proceeding?

A. After additional conversations with our tax experts, I believe the use of a projected PTC rate of 2.9 cents per kilowatt hour for 2024 is supported by the facts insofar as: (1) the inflation adjustment factor has only exceeded year-on-year growth of 4.0 percent or more twice in the past 30 years, and (2) the needed growth to achieve a 2024 PTC rate of 3.0 cents per kilowatt-hour is well in excess of the historic average.

XIX. COMPLIANCE WITH TAM GUIDELINES

Q. Did Staff review the Company's Initial Filing for compliance with the TAM Guidelines?

A. Yes, and Staff concluded that the Company did comply with the TAM Guidelines and prior orders.[174] However, Staff expressed a concern that the Company's Initial Filing did not include analysis of modeling changes that were implemented as part of the settlement of the 2023 TAM on a non-precedential basis.[175] CUB expressed a similar concern.[176]

Q. How do you respond to Staff's and CUB's concern?

A. The TAM Guidelines, as modified in Order No. 09-432, require that the Company identify proposed changes in modeling methodologies as part of the Initial Filing. In this case, the modeling changes identified by Staff were proposed in the 2023 TAM, docket UE 400, and addressed at length in the testimony in that docket. The 2023 TAM was settled, and the settlement allowed the Company to implement the modeling changes proposed in that case on a non-precedential basis. Because the

[174] Staff/100, Kim/10–11.
[175] Staff/100, Kim/12; *see also* Staff/200, Jent/10.
[176] CUB/100, Jenks/9–11.

Company simply carried forward its modeling changes proposed and implemented in the 2023 TAM, the Company's Initial Filing here did not include the same explanation for the modeling changes that did not change from those implemented in the 2023 TAM.

To address Staff's concern, the Company has included an exhibit here, PAC/404, that identifies each non-precedential modeling change that was implemented in the 2023 TAM and included here.

Q. Staff is also concerned that the step log that is included with the Company's TAM filings identifies each modeling change individually, rather than stacking each change on top of the others.[177] How do you respond to this concern?

A. The TAM Guidelines do not require that the steps "stack on top of each other" and the Company does not always take that approach in TAM filings. Furthermore, modeling each change individually more accurately represents the NPC impacts of each change because under a sequential step log paradigm wherein steps "stack on top of each other" the NPC impact of each step is dependent on the position of the step in the log. For example, if the first step change is an update to the OFPC, then that update might increase NPC by $100 million. If the second, stacked step change is an update to short-term firm contracts, then that update might be an NPC increase of $50 million. But if the order of the steps were reversed one could end up with a scenario where the NPC impact of the OFPC as the second step is now $80 million and the NPC impact of updated short-term firm contracts as the first step is now $70 million. By stacking the changes, the step log would distort the impact of each

[177] Staff/100, Kim/12.

individual change because the impact is dependent both on the changed variable and the relative position of that changed variable in the step log.

Q. Has AWEC recognized the potential issue around stacking each change on top of the others?

A. Yes. In AWEC's testimony in docket UE 416, AWEC witness Mullins explained:

> Each of the NPC impacts in this testimony were calculated as one-off adjustments, without considering the impacts of any other adjustments. This was done to isolate the impacts of individual modeling changes, without having the impacts skewed by the order in which the adjustment calculations were performed.[178]

XX. PRE-FINAL ORDER UPDATE

Q. CUB recommends that the Commission direct PacifiCorp to provide updated "information" before the Commission issues its final order in the TAM.[179] Is this a reasonable recommendation?

A. No. First, to the extent CUB requests that the Company provide an updated OFPC in October, before the Commission issues its final order, such a request is unnecessary. The portion of the OFPC that is used to set rates in the TAM is based on publicly available forward market prices that CUB or the Commission can access at any time.

Second, to the extent CUB requests that the Company provide a complete update akin to the Reply Update, such a request is unworkable in the timeframe proposed by CUB. The TAM is already a labor-intensive proceeding, with five rounds of testimony and often hundreds of discovery requests occurring within a compressed procedural schedule. PacifiCorp is able to complete the indicative and

[178] Docket No. UE 416, AWEC/100, Mullins/36.
[179] CUB/100, Jenks/7.

final TAM updates in November on expedited timelines because of extensive planning and pre-work during the months of September and October. Placing another update in October, one month prior to the indicative November update, is unnecessary and administratively unmanageable.

XXI. TRANSITION ADJUSTMENT CALCULATION

Q. Please describe Calpine's proposed adjustment to the calculation of the transition adjustments.

A. Calpine argues that the transition adjustment calculation in Schedules 294, 295, and 296 and the Consumer Opt-Out Charge (collectively referred to as transition adjustments for simplicity) improperly account for the DA/RT adjustment. In particular, Calpine claims that the underlying NPC calculation already includes the DA/RT adjustment and therefore it is "logically unnecessary" to include the DA/RT adjustment in the transition adjustment calculation.[180]

Q. How do you respond to Calpine's recommendation?

A. Calpine's recommendation fails to appropriately account for how the transition adjustments are calculated. To summarize, the portion of the transition adjustments that are under contention are calculated as follows:

- Step 1: Forecast the base NPC. This NPC forecast includes the DA/RT adjustment. Because the base NPC forecast is established using Aurora, it will include both the price and volume component of the DA/RT adjustment. This means that the OFPC input into Aurora will include the DA/RT adjustment's higher purchase price and lower sales price.
- Step 2: Forecast a NPC sensitivity that removes a certain amount of direct access load from the NPC forecast. Like the base NPC forecast in Step 1, the NPC forecast without direct access load also includes the DA/RT adjustment

[180] Calpine Solutions/100, Higgins/7.

in the Aurora model, which ensures that the same OFPC is used in both the base and without-direct-access NPC forecast.

- Step 3: Calculate the megawatt-hour variance at each trading hub and for each generator between the NPC forecasts in Step 1 and Step 2, which is the energy that is "freed up" as a result of departing direct access load. This step then takes that freed-up energy and, for each generator, multiplies the generator's MWh variance by the prices within the OFPC to assess the "market value" of the freed-up energy. This Step 3 is performed in a spreadsheet, not in Aurora, and that spreadsheet includes the OFPC, which is used to determine the "market value" of the energy that is freed up as a result of the direct access load.

Calpine's adjustment would remove the DA/RT adjustment from Step 3. But if the OFPC included in Step 3 does not include the price component of the DA/RT adjustment, then there is an inconsistency between: (1) the forward price curves used to set the 2024 TAM NPC forecast for one set of customers, and used to determine the underlying NPC in Step 1 and Step 2; and (2) the volume of freed up energy and the valuation of that freed up energy used to set the transition adjustments for another set of customers - Step 3. Consistency requires that both the NPC forecast and the transition adjustments calculation use the same forward price curve (one OFPC for all customers), and this one OFPC must therefore include the DA/RT adjustment in Step 3 to calculate transition adjustments.

Q. Calpine further claims that "PacifiCorp selectively limited the DA/RT adjustments solely to the net discounted prices associated with market sales, while ignoring the premium prices associated with market purchases" when determining the transition adjustments.[181] Is this a fair criticism?

A. No. The spreadsheet calculation in Step 3 that determines the market value of

[181] Calpine Solutions/100, Higgins/10.

generation can only use the sales prices, because a generator cannot purchase energy, it can only sell energy. In other words, the valuation of freed-up energy from generation inherently assumes that the Company is *selling* that freed-up energy at a market price and therefore it is reasonable to incorporate only the sales-price adjustment from the DA/RT adjustment in Step 3 of the transition adjustment calculation. Calpine's claim incorrectly assumes that the freed-up energy from generators can be **sold** into the regional electricity markets at a **purchase** price.

Q. Calpine also argues that departing direct access load can not only create an opportunity for increased market sales but also reduce the need for market purchases, which is why the DA/RT adjustment to the purchase price is also necessary in Step 3 of the transition adjustment calculation.[182] How do you respond?

A. When direct access load reduces the need for market purchases, that impact is captured through the MWh variance at trading hubs in Step 3. That trading hub variance pulls in DA/RT adjusted purchase prices from Step 2 and reflects that purchase premium in the transition adjustment calculation. This is not new. In this manner the transition adjustment already receives the DA/RT adjustment's purchase premium.

Q. Does this conclude your reply testimony?

A. Yes.

[182] Calpine Solutions/100, Higgins/9.

Docket No. UE 420
Exhibit PAC/401
Witness: Ramon J. Mitchell

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Ramon J. Mitchell

Step Log Changes

July 2023

Oregon TAM 2024 (April 2023 Initial Filing)		**NPC ($) =**	**2,642,477,625**
		$/MWh =	**39.65**

		Impact ($)	**NPC ($)**
		Total Company	**Total Company**
Corrections			
C01 -	Startup Costs	(7,985,032)	
C02 -	Wind Capacity Factors	(1,914,363)	
C03 -	Contingency Reserves for Non-Owned Generation	50,708,353	
C04 -	DA/RT Volume Component	60,740,729	
Updates			
U01 -	OTR NOx Allowance Aggregation	(155,708,353)	
U02 -	Official Forward Price Curves - Power and Gas	(118,432,737)	
U03 -	Thermal Generation's Marginal Costs	(75,285,976)	
U04 -	OTR NOx Allowances	(16,524,056)	
U05 -	Coal Supply	(1,281,503)	
U06 -	Long-Term Contracts and Online Dates	8,566,313	
U07 -	Short Term Contracts	9,602,475	
U08 -	EIM Benefits	24,059,847	
Total Corrections and Updates		(223,454,303)	
System balancing impact of adjustments		108,807,111	
Total Change from April 2023 Initial Filing		(114,647,192)	
Oregon TAM 2024 (July 2023 Reply Filing)		**NPC ($) =**	**2,527,830,432**
		$/MWh =	**37.93**

Docket No. UE 420
Exhibit PAC/402
Witness: Ramon J. Mitchell

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Ramon J. Mitchell

Oregon-Allocated Net Power Costs

July 2023

PacifiCorp
CY 2024 TAM
Reply Filing

			Total Company						Oregon Allocated		
Line no		ACCT.	UE-400 CY 2023 - Final Filing	TAM CY 2024 - Initial Filing	TAM CY 2024 - Reply Filing	Factor	Factors CY 2023	Factors CY 2024	UE-400 CY 2023 - Final Filing	TAM CY 2024 - Initial Filing	TAM CY 2024 - Reply Filing
1	**Sales for Resale**										
2	Existing Firm PPL	447	6,381,695	-	-	SG	26.002%	28.701%	1,659,353	-	-
3	Existing Firm UPL	447	-	-	-	SG	26.002%	28.701%	-	-	-
4	Post-Merger Firm	447	556,906,202	426,328,887	416,041,280	SG	26.002%	28.701%	144,805,420	122,362,385	119,409,697
5	Non-Firm	447	-	-	-	SE	24.920%	28.515%	-	-	-
6	**Total Sales for Resale**		563,287,897	426,328,887	416,041,280				146,464,773	122,362,385	119,409,697
7											
8	**Purchased Power**										
9	Existing Firm Demand PPL	555	59,530,582	22,795,100	27,788,625	SG	26.002%	28.701%	15,479,000	6,542,514	7,975,726
10	Existing Firm Demand UPL	555	9,126,863	9,531,665	9,200,052	SG	26.002%	28.701%	2,373,145	2,735,722	2,640,544
11	Existing Firm Energy	555	171,504,893	71,888,724	86,683,767	SE	24.920%	28.515%	42,739,259	20,499,156	24,717,980
12	Post-merger Firm	555	1,094,540,292	1,389,718,118	1,317,590,013	SG	26.002%	28.701%	284,599,752	398,868,641	378,166,860
13	Secondary Purchases	555	-	-	-	SE	24.920%	28.515%	-	-	-
14	Other Generation Expense	555	-	-	-	SG	26.002%	28.701%	-	-	-
15	**Total Purchased Power**		1,334,702,630	1,493,933,607	1,441,262,456				345,191,156	428,646,032	413,501,110
16											
17	**Wheeling Expense**										
18	Existing Firm PPL	565	23,886,724	22,898,000	19,834,453	SG	26.002%	28.701%	6,210,969	6,572,048	5,692,767
19	Existing Firm UPL	565	-	-	-	SG	26.002%	28.701%	-	-	-
20	Post-merger Firm	565	124,541,723	134,214,173	138,790,535	SG	26.002%	28.701%	32,383,041	38,521,355	39,834,835
21	Non-Firm	565	6,893,033	9,027,449	10,923,881	SE	24.920%	28.515%	1,717,753	2,574,188	3,114,958
22	**Total Wheeling Expense**		155,321,479	166,139,622	169,548,868				40,311,763	47,667,591	48,642,559
23											
24	**Fuel Expense**										
25	Fuel Consumed - Coal	501	635,260,287	547,388,163	538,341,964	SE	24.920%	28.515%	158,307,751	156,088,389	153,508,855
26	Fuel Consumed - Coal (Cholla)	501	-	-	-	SE	24.920%	28.515%	-	-	-
27	Fuel Consumed - Gas	501	19,326,688	156,802,484	132,206,683	SE	24.920%	28.515%	4,816,238	44,712,416	37,698,894
28	Natural Gas Consumed	547	396,871,314	692,508,768	637,993,977	SE	24.920%	28.515%	98,900,886	197,469,703	181,924,745
29	Simple Cycle Comb. Turbines	547	13,620,689	7,592,963	20,076,862	SE	24.920%	28.515%	3,394,295	2,165,143	5,724,941
30	Steam from Other Sources	503	4,484,106	4,440,902	4,440,902	SE	24.920%	28.515%	1,117,446	1,266,329	1,266,329
31	**Total Fuel Expense**		1,069,563,084	1,408,733,280	1,333,060,389				266,536,615	401,701,979	380,123,763
32											
33	TAM Settlement Adjustment*		(18,844,704)	-	-			-	(4,900,000)	-	-
34											
35	**Net Power Cost (Per Aurora)**		1,977,454,591	2,642,477,623	2,527,830,433				500,674,760	755,653,217	722,857,736
36											
37	Oregon Situs NPC Adustments		(1,091,313)	(905,561)	(762,508)	OR	100.000%	100.000%	(1,091,313)	(905,561)	(762,508)
38	**Total NPC Net of Adjustments**		1,976,363,278	2,641,572,061	2,527,067,926				499,583,447	754,747,655	722,095,228
39											
40	Production Tax Credit (PTC)		(279,202,594)	(280,883,910)	(281,434,085)	SG	26.002%	28.701%	(72,597,592)	(80,617,632)	(80,775,540)
41	**Total TAM Net of Adjustments**		1,697,160,684	2,360,688,151	2,245,633,841				426,985,855	674,130,023	641,319,688
42											
43								Increase Absent Load Change		247,144,168	214,333,833
44											
45				Oregon-allocated NPC (incl. PTC) Baseline in Rates from UE-400					$426,985,855		
46						$ Change due to load variance from UE-400 forecast			$83,509,234		
47						2024 Recovery of NPC (incl. PTC) in Rates			$510,495,090		
48											
49								**Increase Including Load Change**		**$ 163,634,934**	**$ 130,824,599**
50											
51	*TAM Settlement Filing UE-400 - Agreed to decrease Oregon-allocated NPC by $4,900,000.							Add Other Revenue Change		-	-
52											
53								**Total TAM Increase/(Decrease)**		**$ 163,634,934**	**$ 130,824,599**

Docket No. UE 420
Exhibit PAC/403
Witness: Ramon J. Mitchell

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Ramon J. Mitchell

Net Power Costs Report

July 2023

	Total	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24
								Oregon TAM NPC Reply Update					
								$					
Special Sales For Resale													
Long Term Firm Sales													
Black Hills	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hurricane Sale	$ 2,271	$ 2,271	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Leaning Juniper Revenue	$ 324,744	$ 21,949	$ 21,007	$ 21,312	$ 16,865	$ 16,681	$ 22,511	$ 50,638	$ 54,348	$ 35,959	$ 20,405	$ 18,100	$ 24,970
PSCo_Sale	$ 13,548,797	$ 911,135	$ 856,615	$ 882,524	$ 650,060	$ 680,640	$ 872,064	$ 2,208,857	$ 2,250,464	$ 2,059,410	$ 747,395	$ 711,283	$ 718,351
Total Long Term Firm Sales	$ 13,875,811	$ 935,355	$ 877,621	$ 903,836	$ 666,925	$ 697,321	$ 894,575	$ 2,259,495	$ 2,304,812	$ 2,095,368	$ 767,800	$ 729,383	$ 743,321
Short Term Firm Sales													
Borah	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
COB	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Colorado	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Four Corners	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Idaho	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Mead	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Mid Columbia	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Mona	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NOB	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Palo Verde	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SP15	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Utah	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Washington	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
West Main	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wyoming	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Short Term Firm Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
System Balancing Sales													
COB	$ 79,917,521	$ 6,416,121	$ 3,949,746	$ 2,936,072	$ 2,960,484	$ 3,210,541	$ 6,102,938	$ 7,368,625	$ 8,544,233	$ 17,715,725	$ 8,029,065	$ 6,858,465	$ 5,825,506
Four Corners	$ 83,966,244	$ 13,322,003	$ 5,756,722	$ 3,798,260	$ 3,875,195	$ 3,545,137	$ 5,111,662	$ 4,450,910	$ 4,545,913	$ 10,328,290	$ 6,399,105	$ 7,696,845	$ 15,136,202
Mead	$ 2,146,410	$ 201,570	$ 63,037	$ 80,552	$ 60,916	$ 100,041	$ 114,336	$ 314,697	$ 277,732	$ 229,079	$ 992,195	$ 53,078	$ (340,823)
Mid Columbia	$ 164,884,887	$ 21,674,528	$ 13,024,008	$ 7,757,370	$ 8,639,478	$ 5,618,752	$ 7,315,489	$ 21,834,698	$ 25,808,298	$ 15,269,773	$ 9,960,601	$ 11,067,852	$ 16,914,041
Mona	$ 24,135,318	$ 3,309,079	$ 2,327,962	$ 864,852	$ 1,069,920	$ 518,672	$ 1,409,137	$ 2,242,297	$ 2,461,641	$ 4,082,768	$ 1,431,471	$ 1,236,774	$ 3,180,745
NOB	$ 40,192,625	$ 3,879,572	$ 3,804,453	$ 2,636,072	$ 2,251,551	$ 1,748,916	$ 2,591,135	$ 4,120,655	$ 5,737,034	$ 4,524,068	$ 2,655,239	$ 2,850,051	$ 3,393,878
Palo Verde	$ 6,922,463	$ 634,006	$ 460,405	$ 185,959	$ 132,457	$ 165,808	$ 579,810	$ 1,389,222	$ 1,209,854	$ 707,435	$ 460,656	$ 348,377	$ 648,476
Trapped Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total System Balancing Sales	$ 402,165,469	$ 49,436,878	$ 29,386,334	$ 18,259,137	$ 18,990,001	$ 14,907,867	$ 23,224,506	$ 41,721,104	$ 48,584,705	$ 52,857,138	$ 29,928,332	$ 30,111,441	$ 44,758,025
Total Special Sales For Resale	$ 416,041,280	$ 50,372,233	$ 30,263,956	$ 19,162,973	$ 19,656,926	$ 15,605,188	$ 24,119,081	$ 43,980,599	$ 50,889,518	$ 54,952,506	$ 30,696,131	$ 30,840,824	$ 45,501,346

Purchased Power & Net Interchange													
Long Term Firm Purchases													
Appaloosa 1A Solar	$ 10,365,204	$ 562,535	$ 617,749	$ 910,879	$ 983,631	$ 1,151,786	$ 1,216,593	$ 1,065,782	$ 1,038,366	$ 979,390	$ 779,343	$ 579,150	$ 479,999
Appaloosa 1B Solar	$ 6,910,136	$ 375,023	$ 411,832	$ 607,253	$ 655,754	$ 767,857	$ 811,062	$ 710,522	$ 692,244	$ 652,927	$ 519,562	$ 386,100	$ 319,999
Castle Solar UoU	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Castle Solar IHC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cedar Springs Wind	$ 11,764,725	$ 1,348,848	$ 1,136,654	$ 1,032,244	$ 1,016,035	$ 830,825	$ 743,881	$ 742,782	$ 585,990	$ 827,498	$ 1,090,534	$ 1,068,343	$ 1,341,093
Cedar Springs Wind III	$ 8,939,587	$ 1,025,293	$ 863,560	$ 784,236	$ 772,111	$ 631,271	$ 565,347	$ 564,366	$ 445,199	$ 628,829	$ 828,668	$ 811,823	$ 1,018,881
Cedar Springs Wind IV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Combine Hills Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cove Mountain Solar	$ 3,824,831	$ 183,114	$ 199,253	$ 335,342	$ 365,062	$ 420,185	$ 451,894	$ 438,350	$ 414,770	$ 355,679	$ 286,322	$ 205,725	$ 169,135
Cove Mountain Solar II	$ 9,457,003	$ 453,001	$ 492,928	$ 829,598	$ 903,121	$ 1,039,489	$ 1,117,932	$ 1,084,426	$ 1,026,092	$ 879,908	$ 708,326	$ 506,098	$ 416,084
Deseret Purchase	$ 27,312,976	$ 3,228,408	$ 3,115,246	$ 2,944,088	$ 2,880,434	$ 2,774,345	$ 2,719,178	$ 3,228,408	$ 3,228,408	$ 3,194,459	$ -	$ -	$ -
Eagle Mountain - UAMPS/UMPA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Elektron Solar 20yr	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Elektron Solar 25yr	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Gemstate	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Graphite Solar	$ 6,247,480	$ 311,883	$ 365,922	$ 557,963	$ 612,332	$ 686,777	$ 704,723	$ 687,351	$ 642,989	$ 576,256	$ 480,478	$ 355,140	$ 265,665
Hermiston Purchase	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Horseshoe Solar	$ 6,115,081	$ 268,027	$ 344,622	$ 502,043	$ 568,585	$ 677,881	$ 750,557	$ 737,711	$ 699,020	$ 581,446	$ 467,167	$ 288,744	$ 229,279
Hunter Solar	$ 7,031,207	$ 369,331	$ 433,652	$ 637,866	$ 665,722	$ 759,120	$ 785,546	$ 746,797	$ 702,015	$ 654,578	$ 558,601	$ 396,190	$ 321,788
Hurricane Purchase	$ 46,925	$ 46,925	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
MagCorp Buythru	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
MagCorp Reserves	$ 3,264,140	$ 272,680	$ 264,660	$ 272,680	$ 272,680	$ 272,680	$ 272,680	$ 272,680	$ 272,680	$ 272,680	$ 272,680	$ 272,680	$ 272,680
Milican Solar	$ 2,898,880	$ 95,313	$ 150,647	$ 222,859	$ 280,511	$ 332,937	$ 362,395	$ 408,109	$ 360,617	$ 290,222	$ 190,032	$ 121,715	$ 83,523
Milford Solar	$ 6,937,492	$ 350,630	$ 418,195	$ 595,592	$ 662,485	$ 778,851	$ 821,177	$ 731,293	$ 704,005	$ 656,707	$ 529,625	$ 385,321	$ 303,612
Nucor	$ 7,129,800	$ 594,150	$ 594,150	$ 594,150	$ 594,150	$ 594,150	$ 594,150	$ 594,150	$ 594,150	$ 594,150	$ 594,150	$ 594,150	$ 594,150
Old Mill Solar	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Monsanto Reserves	$ 20,600,000	$ 1,716,667	$ 1,716,667	$ 1,716,667	$ 1,716,667	$ 1,716,667	$ 1,716,667	$ 1,716,667	$ 1,716,667	$ 1,716,667	$ 1,716,667	$ 1,716,667	$ 1,716,667
Pavant III Solar	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PGE Cove	$ 164,065	$ 13,672	$ 13,672	$ 13,672	$ 13,672	$ 13,672	$ 13,672	$ 13,672	$ 13,672	$ 13,672	$ 13,672	$ 13,672	$ 13,672
Prineville Solar	$ 1,931,376	$ 65,430	$ 103,415	$ 148,062	$ 186,364	$ 221,194	$ 240,766	$ 271,137	$ 239,584	$ 192,816	$ 126,252	$ 80,864	$ 55,491
Rocket Solar	$ 6,518,690	$ 295,778	$ 369,445	$ 537,993	$ 609,687	$ 712,494	$ 800,701	$ 820,796	$ 742,700	$ 624,428	$ 474,844	$ 290,098	$ 239,725
Sigurd Solar	$ 5,900,441	$ 308,030	$ 356,200	$ 507,232	$ 553,807	$ 636,517	$ 699,580	$ 650,415	$ 596,230	$ 556,646	$ 451,695	$ 317,435	$ 266,651
Skysol Solar	$ 6,429,148	$ 322,157	$ 365,293	$ 530,598	$ 561,018	$ 620,581	$ 804,541	$ 862,576	$ 762,459	$ 552,791	$ 484,197	$ 285,081	$ 277,856
Small Purchases east	$ 56,994	$ 5,531	$ 5,198	$ 6,394	$ 4,636	$ 3,869	$ 3,916	$ 3,691	$ 4,013	$ 5,487	$ 4,428	$ 4,478	$ 5,355
Small Purchases west	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Soda Lake Geotherma	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Three Buttes Wind	$ 20,638,860	$ 2,782,809	$ 1,915,027	$ 2,129,777	$ 1,611,562	$ 1,423,643	$ 1,202,365	$ 803,345	$ 946,962	$ 1,181,835	$ 1,730,465	$ 2,346,165	$ 2,564,905
Top of the World Wind	$ 37,921,726	$ 3,211,949	$ 3,004,727	$ 3,211,949	$ 3,108,338	$ 3,211,949	$ 3,108,338	$ 3,211,949	$ 3,211,949	$ 3,108,338	$ 3,211,949	$ 3,108,338	$ 3,211,949
Wolverine Creek Wind	$ 10,678,106	$ 789,484	$ 937,544	$ 1,175,634	$ 1,081,742	$ 816,828	$ 877,518	$ 695,099	$ 661,159	$ 780,865	$ 859,564	$ 999,302	$ 1,003,367
Glen Canyon	$ 337,293	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,616	$ 325,678
Rush Lake	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Fremont Solar	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Green River Energy Cente	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Anticline Wind	$ 18,483	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 18,483
Boswell Springs Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Two River Wind LLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cedar Creek	$ 9,767,806	$ -	$ -	$ -	$ -	$ -	$ 19,440	$ 1,368,669	$ 1,082,327	$ 1,300,232	$ 2,171,667	$ 2,121,175	$ 1,704,296
OR Schedule 126 CSF	$ 4,373,271	$ 226,605	$ 216,386	$ 105,263	$ 349,994	$ 297,608	$ 537,032	$ 673,424	$ 854,450	$ 409,118	$ 302,204	$ 221,442	$ 179,746
UT Schedule Adjustment	$ (37,466,244)	$ (1,680,691)	$ (2,018,190)	$ (3,360,173)	$ (3,749,047)	$ (4,450,727)	$ (4,535,849)	$ (4,239,494)	$ (3,966,063)	$ (3,437,166)	$ (2,845,889)	$ (1,819,486)	$ (1,363,469)
Long Term Firm Purchases Total	$ 206,115,480	$ 17,542,583	$ 16,394,453	$ 17,549,862	$ 17,281,052	$ 16,942,452	$ 17,405,803	$ 18,864,674	$ 18,272,655	$ 18,150,460	$ 16,007,204	$ 15,668,025	$ 16,036,258

Qualifying Facilities													
QF California	$ 1,691,846	$ 144,138	$ 144,080	$ 156,633	$ 157,919	$ 137,956	$ 134,286	$ 135,609	$ 134,441	$ 129,611	$ 135,806	$ 142,268	$ 139,098
QF Idaho	$ 7,384,439	$ 605,201	$ 543,397	$ 628,658	$ 669,151	$ 756,864	$ 745,232	$ 653,778	$ 555,366	$ 520,800	$ 585,228	$ 559,512	$ 561,253
QF Oregon	$ 41,585,975	$ 2,282,896	$ 2,731,056	$ 3,654,769	$ 4,549,011	$ 4,603,695	$ 4,747,221	$ 4,926,335	$ 4,249,316	$ 3,536,881	$ 2,762,393	$ 1,960,706	$ 1,581,696
QF Utah	$ 6,089,886	$ 359,738	$ 403,638	$ 480,494	$ 577,328	$ 633,629	$ 651,580	$ 593,828	$ 598,393	$ 589,272	$ 510,766	$ 383,475	$ 307,746
QF Washington	$ 231,336	$ -	$ -	$ -	$ 22,559	$ 23,311	$ 44,799	$ 46,293	$ 46,293	$ 44,799	$ 3,283	$ -	$ -
QF Wyoming	$ 200,103	$ 24,584	$ 18,617	$ 23,206	$ 19,704	$ 18,046	$ 6,756	$ 10,630	$ 11,984	$ 17,488	$ 16,668	$ 18,738	$ 13,681
Biomass One QF	$ 18,728,743	$ 1,669,991	$ 1,503,089	$ 1,600,266	$ 1,569,336	$ 1,761,538	$ 1,692,832	$ 1,567,580	$ 1,622,548	$ 1,601,615	$ 1,636,336	$ 1,646,005	$ 857,607
Chopin Wind QF	$ 2,052,812	$ 193,044	$ 216,789	$ 168,226	$ 188,753	$ 161,939	$ 177,933	$ 160,795	$ 152,387	$ 133,330	$ 156,651	$ 177,435	$ 165,528
DCFP QF	$ 159,456	$ 3,732	$ 1,487	$ 1,273	$ 2,265	$ 4,211	$ 7,319	$ 35,101	$ 40,867	$ 30,521	$ 11,304	$ 9,753	$ 11,623
Enterprise Solar I QF	$ 12,435,106	$ 605,776	$ 772,740	$ 956,940	$ 1,100,161	$ 1,246,936	$ 1,367,030	$ 1,552,309	$ 1,503,979	$ 1,167,844	$ 940,221	$ 689,473	$ 531,699
Escalante Solar I QF	$ 11,472,692	$ 556,159	$ 702,390	$ 861,800	$ 1,001,202	$ 1,180,119	$ 1,278,616	$ 1,437,770	$ 1,392,853	$ 1,080,012	$ 857,708	$ 627,972	$ 496,091
Escalante Solar II QF	$ 10,812,672	$ 522,020	$ 659,365	$ 811,762	$ 941,605	$ 1,115,246	$ 1,221,823	$ 1,369,295	$ 1,305,905	$ 1,011,320	$ 804,026	$ 587,622	$ 462,683
Escalante Solar III QF	$ 9,946,598	$ 507,994	$ 644,271	$ 787,602	$ 915,846	$ 1,089,984	$ 731,324	$ 1,315,175	$ 1,267,280	$ 988,913	$ 735,783	$ 538,302	$ 424,125
ExxonMobil QF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Five Pine Wind QF	$ 9,671,086	$ 591,751	$ 990,114	$ 867,657	$ 914,134	$ 563,035	$ 616,150	$ 720,681	$ 687,308	$ 858,470	$ 842,118	$ 1,008,291	$ 1,011,378
Granite Mountain East Solar QF	$ 10,791,197	$ 538,975	$ 634,052	$ 873,532	$ 974,584	$ 1,149,968	$ 1,244,331	$ 1,333,659	$ 1,255,131	$ 964,311	$ 795,497	$ 570,005	$ 457,151
Granite Mountain West Solar QF	$ 7,127,437	$ 357,192	$ 420,253	$ 579,379	$ 646,457	$ 761,867	$ 823,479	$ 883,781	$ 831,879	$ 634,512	$ 509,122	$ 377,046	$ 302,471
Iron Springs Solar QF	$ 11,087,085	$ 623,624	$ 681,626	$ 875,888	$ 1,002,096	$ 1,123,768	$ 1,269,977	$ 1,344,268	$ 1,314,577	$ 992,818	$ 802,236	$ 568,232	$ 487,975
Latigo Wind Park QF	$ 9,807,110	$ 1,008,523	$ 974,723	$ 1,127,257	$ 888,162	$ 870,272	$ 743,515	$ 692,426	$ 567,983	$ 624,983	$ 806,218	$ 704,856	$ 798,194
Mountain Wind 1 QF	$ 8,949,411	$ 1,411,927	$ 1,077,712	$ 873,605	$ 691,027	$ 491,070	$ 503,734	$ 408,518	$ 438,466	$ 463,488	$ 664,617	$ 919,705	$ 1,005,544
Mountain Wind 2 QF	$ 13,853,973	$ 2,046,500	$ 1,604,687	$ 1,344,052	$ 1,068,792	$ 764,887	$ 901,569	$ 749,654	$ 723,615	$ 763,905	$ 992,941	$ 1,414,981	$ 1,478,389
North Point Wind QF	$ 20,544,761	$ 1,180,761	$ 2,028,043	$ 1,836,607	$ 1,950,796	$ 1,193,212	$ 1,325,700	$ 1,590,909	$ 1,616,707	$ 1,938,184	$ 1,860,511	$ 2,035,525	$ 1,987,806
Oregon Wind Farm QF	$ 13,319,112	$ 1,023,863	$ 1,189,669	$ 824,060	$ 957,933	$ 677,064	$ 820,732	$ 1,639,189	$ 2,076,126	$ 1,223,711	$ 617,187	$ 836,690	$ 1,432,888
Orchard Wind 1 QF	$ 1,137,294	$ 63,171	$ 69,701	$ 97,721	$ 124,816	$ 110,803	$ 123,524	$ 123,449	$ 105,362	$ 79,489	$ 84,148	$ 75,107	$ 80,003
Orchard Wind 2 QF	$ 1,137,294	$ 61,356	$ 68,707	$ 91,023	$ 124,993	$ 112,506	$ 123,255	$ 125,420	$ 106,117	$ 79,928	$ 85,657	$ 76,765	$ 81,568
Orchard Wind 3 QF	$ 1,137,294	$ 63,522	$ 66,945	$ 105,763	$ 122,943	$ 112,010	$ 124,350	$ 121,662	$ 105,662	$ 78,908	$ 84,637	$ 72,465	$ 78,427
Orchard Wind 4 QF	$ 1,137,294	$ 63,331	$ 69,219	$ 103,949	$ 122,994	$ 111,676	$ 123,692	$ 122,969	$ 105,683	$ 78,915	$ 82,859	$ 73,472	$ 78,535
Pavant II Solar QF	$ 5,372,997	$ 216,445	$ 279,842	$ 401,431	$ 472,730	$ 542,030	$ 588,172	$ 726,782	$ 733,884	$ 532,014	$ 406,233	$ 261,448	$ 211,986
Pioneer Wind Park I QF	$ 10,582,411	$ 1,293,636	$ 967,174	$ 1,174,063	$ 894,062	$ 700,161	$ 641,503	$ 654,205	$ 677,246	$ 444,202	$ 807,854	$ 1,251,420	$ 1,076,883
Power County North Wind QF	$ 6,131,339	$ 463,416	$ 613,435	$ 589,598	$ 578,227	$ 403,826	$ 390,685	$ 412,984	$ 408,970	$ 424,405	$ 567,501	$ 590,091	$ 688,202
Power County South Wind QF	$ 5,493,138	$ 411,220	$ 542,794	$ 535,139	$ 539,566	$ 350,995	$ 350,065	$ 367,273	$ 383,050	$ 377,980	$ 498,816	$ 535,407	$ 600,833
Roseburg Dillard QF	$ 1,874,755	$ 101,657	$ 187,741	$ 116,442	$ 139,347	$ 174,654	$ 85,173	$ 283,625	$ 185,360	$ 111,759	$ 95,262	$ 138,831	$ 254,905
Sage I Solar QF	$ 2,228,767	$ 79,115	$ 80,953	$ 185,750	$ 201,479	$ 231,609	$ 255,841	$ 332,541	$ 328,474	$ 203,969	$ 152,736	$ 102,564	$ 73,738
Sage II Solar QF	$ 2,227,276	$ 79,198	$ 81,049	$ 185,945	$ 201,695	$ 230,934	$ 256,127	$ 330,821	$ 328,839	$ 203,129	$ 152,889	$ 102,978	$ 73,674
Sage III Solar QF	$ 1,833,444	$ 66,690	$ 67,449	$ 153,415	$ 164,218	$ 189,832	$ 209,266	$ 269,677	$ 267,843	$ 167,470	$ 128,126	$ 86,929	$ 62,528
Spanish Fork Wind 2 QF	$ 2,831,535	$ 224,537	$ 192,044	$ 208,643	$ 165,062	$ 156,982	$ 216,357	$ 297,964	$ 323,818	$ 278,809	$ 251,063	$ 260,112	$ 256,145
Sunnyside QF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sweetwater Solar QF	$ 7,627,672	$ 254,931	$ 379,040	$ 551,639	$ 673,027	$ 797,595	$ 957,706	$ 1,095,186	$ 1,019,583	$ 792,992	$ 615,295	$ 294,026	$ 196,650
Tesoro QF	$ 293,400	$ 30,563	$ 63,947	$ 46,439	$ 27,998	$ 13,143	$ 5,257	$ 119	$ 2,314	$ 9,089	$ 9,044	$ 17,624	$ 67,863
Three Peaks Solar QF	$ 8,497,104	$ 410,390	$ 492,863	$ 614,683	$ 835,185	$ 872,227	$ 913,479	$ 1,072,814	$ 1,017,830	$ 791,169	$ 669,197	$ 440,297	$ 366,970
Threemile Canyon Wind QF	$ 1,802,363	$ 82,972	$ 180,579	$ 139,659	$ 183,820	$ 181,293	$ 218,186	$ 208,329	$ 181,311	$ 120,822	$ 125,922	$ 99,256	$ 80,214
Utah Pavant Solar QF	$ 7,331,825	$ 286,427	$ 350,863	$ 542,142	$ 636,557	$ 760,728	$ 845,521	$ 996,360	$ 925,894	$ 767,702	$ 566,106	$ 357,167	$ 296,358
Utah Red Hills Solar QF	$ 11,487,402	$ 480,440	$ 640,061	$ 773,732	$ 1,020,201	$ 1,193,809	$ 1,227,730	$ 1,539,540	$ 1,463,201	$ 1,311,693	$ 800,670	$ 581,951	$ 454,373
Qualifying Facilities Total	$ 308,107,444	$ 20,991,402	$ 23,336,202	$ 25,950,847	$ 28,037,739	$ 27,575,428	$ 28,711,826	$ 32,249,303	$ 31,063,844	$ 26,171,236	$ 23,230,634	$ 21,194,503	$ 19,594,480
Mid-Columbia Contracts													
Douglas - Wells	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Grant Reasonable	$ (9,177,438)	$ (764,786)	$ (764,786)	$ (764,786)	$ (764,786)	$ (764,786)	$ (764,786)	$ (764,786)	$ (764,786)	$ (764,786)	$ (764,786)	$ (764,786)	$ (764,786)
Grant Meaningful Priority	$ 75,858,709	$ 6,321,559	$ 6,321,559	$ 6,321,559	$ 6,321,559	$ 6,321,559	$ 6,321,559	$ 6,321,559	$ 6,321,559	$ 6,321,559	$ 6,321,559	$ 6,321,559	$ 6,321,559
Grant Surplus	$ 2,472,617	$ 206,051	$ 206,051	$ 206,051	$ 206,051	$ 206,051	$ 206,051	$ 206,051	$ 206,051	$ 206,051	$ 206,051	$ 206,051	$ 206,051
Mid-Columbia Contracts Total	$ 69,153,888	$ 5,762,824	$ 5,762,824	$ 5,762,824	$ 5,762,824	$ 5,762,824	$ 5,762,824	$ 5,762,824	$ 5,762,824	$ 5,762,824	$ 5,762,824	$ 5,762,824	$ 5,762,824
Total Long Term Firm Purchases	$ 583,376,812	$ 44,296,809	$ 45,493,479	$ 49,263,533	$ 51,081,616	$ 50,280,704	$ 51,880,452	$ 56,876,801	$ 55,099,323	$ 50,084,520	$ 45,000,661	$ 42,625,351	$ 41,393,562

Storage & Exchange													
Rush lake BESS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Fremont Solar_BESS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Green River Energy Center BESS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Umpqua Storage Placeholder	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cowlitz Swift	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
EWEB FC I	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PSCo Exchange	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PSCO FC III	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SCL State Line	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage & Exchange	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Short Term Firm Purchases													
COB	$ 54,195,300	$ 6,325,800	$ 6,082,500	$ 6,325,800	$ -	$ -	$ -	$ 11,970,600	$ 12,370,200	$ 11,120,400	$ -	$ -	$ -
Colorado	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Four Corners	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Idaho	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Mead	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Mid Columbia	$ 33,730,760	$ 1,931,280	$ 1,857,000	$ 1,931,280	$ 3,551,600	$ 3,551,600	$ 4,045,000	$ 5,694,000	$ 5,913,000	$ 5,256,000	$ -	$ -	$ -
Mona	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NOB	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Palo Verde	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SP15	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Utah	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Washington	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
West Main	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wyoming	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Short Term Firm Purchases	$ 87,926,060	$ 8,257,080	$ 7,939,500	$ 8,257,080	$ 3,551,600	$ 3,551,600	$ 4,045,000	$ 17,664,600	$ 18,283,200	$ 16,376,400	$ -	$ -	$ -
System Balancing Purchases													
COB	$ 44,700,597	$ 3,612,935	$ 5,196,873	$ 5,603,356	$ 2,217,154	$ 957,805	$ 3,535,078	$ 4,969,495	$ 5,461,305	$ 5,326,783	$ 1,938,088	$ 2,701,515	$ 3,180,210
Four Corners	$ 51,518,961	$ 4,911,104	$ 4,252,480	$ 2,455,342	$ 1,900,058	$ 1,082,176	$ 3,093,180	$ 10,907,373	$ 6,087,399	$ 6,829,975	$ 2,349,224	$ 3,137,272	$ 4,513,379
Mead	$ 2,826,533	$ 60,737	$ (2,217)	$ (3,125)	$ 163,243	$ 17,193	$ 207,041	$ 24,047	$ 388,490	$ 726,841	$ 170,080	$ 48,520	$ 1,025,683
Mid Columbia	$ 566,211,410	$ 55,179,385	$ 42,369,424	$ 37,426,583	$ 34,166,325	$ 18,120,317	$ 33,194,082	$ 88,866,864	$ 91,929,704	$ 51,293,339	$ 25,070,373	$ 33,650,654	$ 54,944,360
Mona	$ 45,499,790	$ 4,193,610	$ 2,780,755	$ 2,465,576	$ 2,332,671	$ 1,354,148	$ 1,967,966	$ 7,990,070	$ 5,184,003	$ 4,655,650	$ 3,447,925	$ 3,094,068	$ 6,033,348
NOB	$ 139,255,885	$ 13,801,463	$ 13,029,200	$ 8,842,789	$ 5,015,907	$ 4,178,433	$ 6,637,701	$ 18,316,778	$ 19,003,984	$ 15,070,356	$ 7,349,638	$ 11,380,576	$ 16,629,060
Palo Verde	$ 26,368,234	$ 2,811,208	$ 1,113,304	$ 1,707,807	$ 926,110	$ 954,982	$ 1,597,962	$ 4,698,813	$ 4,253,035	$ 1,242,209	$ 3,199,217	$ 2,020,156	$ 1,843,433
EIM Imports/Exports	$ (107,981,006)	$ (11,184,399)	$ (9,180,912)	$ (7,491,298)	$ (6,708,794)	$ (6,428,175)	$ (6,655,048)	$ (11,996,478)	$ (12,960,242)	$ (10,544,270)	$ (6,449,442)	$ (7,258,941)	$ (11,123,005)
Emergency Purchases	$ 1,559,179	$ 26,797	$ 2,921	$ -	$ 96,354	$ -	$ -	$ 315,340	$ 1,099,777	$ -	$ -	$ -	$ 17,990
Total System Balancing Purchases	$ 769,959,584	$ 73,412,839	$ 59,561,827	$ 51,007,030	$ 40,109,027	$ 20,236,880	$ 43,577,961	$ 124,092,301	$ 120,447,455	$ 74,600,883	$ 37,075,102	$ 48,773,821	$ 77,064,458
Total Purchased Power & Net Interchange	$ 1,441,262,456	$ 125,966,728	$ 112,994,807	$ 108,527,643	$ 94,742,243	$ 74,069,184	$ 99,503,413	$ 198,633,701	$ 193,829,978	$ 141,061,803	$ 82,075,764	$ 91,399,172	$ 118,458,020
Wheeling & U. of F. Expense													
Firm Wheeling	$ 166,964,094	$ 12,354,670	$ 12,989,372	$ 13,803,474	$ 13,891,817	$ 13,166,465	$ 13,760,055	$ 14,658,565	$ 14,843,837	$ 14,600,528	$ 13,832,764	$ 13,901,636	$ 15,160,910
C&T EIM Admin fee	$ 2,584,773	$ 210,477	$ 192,813	$ 230,652	$ 220,405	$ 231,652	$ 233,135	$ 238,944	$ 221,226	$ 240,569	$ 181,475	$ 188,935	$ 194,490
ST Firm & Non-Firm	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Wheeling & U. of F. Expense	$ 169,548,867	$ 12,565,147	$ 13,182,186	$ 14,034,125	$ 14,112,222	$ 13,398,116	$ 13,993,190	$ 14,897,509	$ 15,065,064	$ 14,841,097	$ 14,014,239	$ 14,090,571	$ 15,355,400
Coal Fuel Burn Expense													
Colstrip	$ 19,248,233	$ 1,301,239	$ 1,619,734	$ 1,703,990	$ 1,466,304	$ 1,203,871	$ 964,045	$ 1,911,630	$ 1,891,461	$ 1,910,473	$ 1,859,225	$ 1,867,136	$ 1,549,126
Craig	$ 24,627,149	$ 2,162,985	$ 1,843,032	$ 1,761,348	$ 1,575,608	$ 1,922,478	$ 1,985,441	$ 2,136,347	$ 2,301,023	$ 2,318,915	$ 2,178,590	$ 2,093,716	$ 2,347,666
Dave Johnston	$ 57,903,585	$ 4,597,351	$ 4,441,136	$ 5,196,133	$ 4,215,496	$ 3,916,699	$ 4,819,012	$ 4,676,861	$ 5,631,630	$ 4,464,097	$ 5,301,185	$ 4,824,414	$ 5,819,570
Hayden	$ 11,326,571	$ 934,386	$ 983,347	$ 778,716	$ 665,199	$ 891,953	$ 925,035	$ 1,016,931	$ 1,074,832	$ 979,113	$ 1,099,645	$ 938,533	$ 1,038,882
Hunter	$ 157,957,315	$ 22,071,691	$ 15,973,522	$ 6,114,277	$ 9,392,104	$ 7,902,872	$ 9,446,576	$ 22,940,602	$ 19,713,207	$ 12,945,988	$ 9,011,960	$ 9,143,339	$ 13,301,176
Huntington	$ 76,807,783	$ 11,363,857	$ 8,104,178	$ 4,579,434	$ 4,270,670	$ 3,604,782	$ 4,495,094	$ 10,916,336	$ 9,469,117	$ 5,661,444	$ 3,942,167	$ 3,979,224	$ 6,421,479
Jim Bridger	$ 130,005,439	$ 10,218,416	$ 10,353,337	$ 10,177,752	$ 9,603,185	$ 10,956,709	$ 8,126,772	$ 13,072,323	$ 13,391,069	$ 12,031,492	$ 10,121,616	$ 10,523,711	$ 11,429,060
Naughton	$ 35,633,257	$ 3,780,675	$ 3,631,250	$ 3,290,289	$ 3,349,836	$ 2,783,086	$ 3,380,195	$ 2,921,876	$ 1,649,207	$ 1,541,416	$ 2,913,839	$ 3,135,031	$ 3,256,555
Wyodak	$ 24,832,632	$ 2,224,987	$ 2,040,214	$ 1,598,343	$ 2,224,097	$ 1,644,630	$ 1,952,300	$ 1,898,753	$ 2,255,029	$ 2,100,905	$ 2,558,121	$ 1,814,099	$ 2,521,152
Total Coal Fuel Burn Expense	$ 538,341,964	$ 58,655,587	$ 48,989,749	$ 35,200,283	$ 36,762,500	$ 34,827,080	$ 36,094,470	$ 61,491,660	$ 57,376,574	$ 43,953,843	$ 38,986,346	$ 38,319,205	$ 47,684,668

Gas Fuel Burn Expense													
Chehalis	$ 170,274,542	$ 26,651,333	$ 18,035,788	$ 13,334,072	$ 9,891,838	$ 11,503,690	$ 10,468,895	$ 13,086,939	$ 12,431,447	$ 10,792,646	$ 10,550,177	$ 13,828,325	$ 19,699,393
Currant Creek	$ 107,177,861	$ 14,494,015	$ 13,382,995	$ 8,836,469	$ 6,714,633	$ 6,909,718	$ 6,126,015	$ 7,416,476	$ 7,212,094	$ 7,762,779	$ 7,733,657	$ 8,200,520	$ 12,388,490
Gadsby	$ 28,715,198	$ 3,590,834	$ 3,645,701	$ 2,419,491	$ 1,543,907	$ 1,604,350	$ 1,935,482	$ 1,950,688	$ 2,214,278	$ 1,879,012	$ 1,945,790	$ 2,529,496	$ 3,456,169
Gadsby CT	$ 20,076,862	$ 2,441,081	$ 2,307,285	$ 1,498,820	$ 1,077,557	$ 1,870,984	$ 1,704,274	$ 1,296,127	$ 1,489,368	$ 1,318,778	$ 1,265,105	$ 1,562,393	$ 2,245,090
Hermiston	$ 40,599,768	$ 5,737,137	$ 4,934,705	$ 2,085,187	$ 1,826,254	$ 2,556,472	$ 1,884,571	$ 2,323,288	$ 3,634,021	$ 3,476,121	$ 3,667,056	$ 4,244,627	$ 4,230,329
Jim Bridger - Gas	$ 103,491,485	$ -	$ -	$ 4,468,191	$ 4,067,995	$ 6,982,209	$ 10,654,087	$ 12,184,005	$ 13,133,407	$ 11,359,771	$ 11,811,696	$ 12,208,434	$ 16,621,691
Lake Side 1	$ 114,846,887	$ 14,305,979	$ 13,714,998	$ 8,349,045	$ 6,292,660	$ 7,540,223	$ 7,462,522	$ 8,262,252	$ 8,596,884	$ 8,483,130	$ 7,597,289	$ 10,451,726	$ 13,790,178
Lake Side 2	$ 131,401,125	$ 17,616,817	$ 15,591,259	$ 11,525,252	$ 3,277,274	$ 4,121,373	$ 9,134,305	$ 10,223,359	$ 10,671,518	$ 9,837,776	$ 9,812,161	$ 12,788,255	$ 16,801,776
Naughton - Gas	$ 32,662,819	$ 2,976,964	$ 3,157,781	$ 3,008,711	$ 695,889	$ 2,998,441	$ 3,473,390	$ 2,504,021	$ 2,984,705	$ 2,844,609	$ 1,363,356	$ 3,568,398	$ 3,086,556
Total Gas Fuel Burn	$ 749,246,547	$ 87,814,159	$ 74,770,511	$ 55,525,239	$ 35,388,005	$ 46,087,461	$ 52,843,540	$ 59,247,153	$ 62,367,724	$ 57,754,622	$ 55,746,287	$ 69,382,174	$ 92,319,673
Gas Physica	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Gas Swaps	$ (2,173,320)	$ (11,212,855)	$ (7,609,528)	$ 5,974,475	$ 1,206,750	$ 2,136,985	$ 1,584,750	$ 814,254	$ 465,000	$ 1,095,150	$ 3,252,365	$ 3,429,863	$ (3,310,529)
Clay Basin Gas Storage	$ (2,019,909)	$ (775,564)	$ (693,925)	$ (179,008)	$ 52,242	$ 52,242	$ 52,242	$ 52,242	$ 52,242	$ 52,242	$ 52,242	$ (169,614)	$ (567,495)
Pipeline Reservation Fees	$ 45,224,205	$ 3,788,842	$ 3,714,880	$ 3,787,396	$ 3,753,575	$ 3,783,194	$ 3,746,799	$ 3,787,479	$ 3,785,315	$ 3,750,925	$ 3,786,974	$ 3,750,914	$ 3,787,911
Total Gas Fuel Burn Expense	$ 790,277,523	$ 79,614,583	$ 70,181,938	$ 65,108,101	$ 40,400,572	$ 52,059,882	$ 58,227,331	$ 63,901,128	$ 66,670,282	$ 62,652,939	$ 62,837,868	$ 76,393,337	$ 92,229,560
Other Generation Expense													
Blundell	$ 4,440,902	$ 443,392	$ 228,935	$ 88,076	$ 360,802	$ 379,715	$ 391,298	$ 418,061	$ 430,310	$ 413,742	$ 401,326	$ 431,972	$ 453,273
Blundell Bottoming Cycle	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cedar Springs Wind II	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dunlap I Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ekola Flats Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Foote Creek I Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Foote Creek II Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Foote Creek III Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Foote Creek IV Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Glenrock Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Glenrock III Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Goodnoe Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
High Plains Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Leaning Juniper 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Marengo I Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Marengo II Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
McFadden Ridge Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Pryor Mountain Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rolling Hills Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Seven Mile Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Seven Mile II Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Black Cap Solar	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TB Flats Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TB Flats Wind II	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rock Creek 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rock Creek 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rock River 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Integration Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Other Generation Expense	$ 4,440,902	$ 443,392	$ 228,935	$ 88,076	$ 360,802	$ 379,715	$ 391,298	$ 418,061	$ 430,310	$ 413,742	$ 401,326	$ 431,972	$ 453,273
Net Power Cost	**$ 2,527,830,432**	**$ 226,873,204**	**$ 215,313,658**	**$ 203,795,256**	**$ 166,721,414**	**$ 159,128,789**	**$ 184,090,622**	**$ 295,361,460**	**$ 282,482,691**	**$ 207,970,919**	**$ 167,619,411**	**$ 189,793,433**	**$ 228,679,576**

Docket No. UE 420
Exhibit PAC/404
Witness: Ramon J. Mitchell

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Ramon J. Mitchell

Modeling Refinements and Sensitivities

July 2023

ID	Sensitivity	Type	Description	Base Run	Sensitivity NPC	Base NPC ($)	NPC Impact ($)	Oregon Allocated
S01	Market_Capacity_Limits	Sensitivity	Moving from the third quartile of averages to the average of averages market capacity methodology	Base	2,509,281,197	2,527,830,432	18,549,235	5,323,891
S02	DART_Percentile_Adder	Sensitivity	Moving from a flat DART adder to a percentile DART adder	Base	2,480,354,657	2,527,830,432	47,475,776	13,626,215
S03	Regulation_Reserves	Sensitivity	Moving from the 2019 IRP to the most recently approved IRP (2021 IRP) for regulation reserves	Base	2,468,377,141	2,527,830,432	59,453,292	17,063,931
S04	Budgeted_Outages	Sensitivity	Moving from normalized outages to budgeted outages	Base	2,546,188,631	2,527,830,432	(18,358,198)	(5,269,061)
S05	WY_OTR (Ozone Transport Rule - Wyoming)	Sensitivity	Moving from Utah only in the OTR to both Utah and Wyoming in the OTR	Base	2,518,400,715	2,527,830,432	9,429,717	2,706,461
U03	Thermal Generation Marginal Costs	Sensitivity	Modification to Aurora's modeling logic that changes the in-model marginal cost evaluation of coal/gas	Base	2,603,116,409	2,527,830,432	(75,285,976)	(21,608,134)

REDACTED
Docket No. UE 420
Exhibit PAC/500
Witness: James Owen

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Reply Testimony of James Owen

July 2023

TABLE OF CONTENTS

ATTACHED EXHIBITS

Q. Are you the same James Owen who previously submitted direct testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company)?

A. Yes.

I. PURPOSE AND SUMMARY OF TESTIMONY

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

A. I respond to the opening testimony of Rose Anderson, filed on behalf of the Public Utility Commission of Oregon (Commission) Staff; Bob Jenks, on behalf of the Oregon Citizens' Utility Board (CUB); Bradley G. Mullins, on behalf of the Alliance of Western Energy Consumers (AWEC); Steve Johnson, filed on behalf of Vitesse, LLC (Vitesse), and Ed Burgess and Maria Roumpani, filed on behalf of Sierra Club.

Q. Please summarize your testimony.

A. In my testimony, I provide a review of how coal costs were revised in the Transition Adjustment Mechanism (TAM) Reply Update, and briefly describe the analysis the Company completed prior to executing the Wolverine coal supply agreement (CSA) for the Hunter plant (Hunter/Wolverine CSA), which had not been executed at the time of the Initial Filing in this proceeding. Additionally, I respond to the following arguments from Staff, CUB, AWEC, Vitesse, and Sierra Club:

- I respond to Staff's and Sierra Club's questions and concerns about the current Utah coal market and explain how the Company has negotiated prudent and reasonable CSAs for the Hunter plant, despite supply constraints and high demand;
- In response to adjustments and concerns from AWEC, CUB, and Vitesse, I

provide background on the application of the Ozone Transport Rule (OTR) and how the Company expects this rule to operate in 2024. I address CUB's question on how the Company considers operating constraints from the OTR in negotiating and assessing minimum take and liquidated damages provisions in CSAs;

- Finally, in response to Sierra Club's concerns regarding fuel supply for the Jim Bridger plant, I explain that consistent with the current Long-Term Fuel Supply Plan for the Jim Bridger plant (2023 Fuel Plan), the Company elected against a new CSA with the Black Butte mine. I also respond to Sierra Club's criticism of the 2023 Fuel Plan.

II. TAM REPLY UPDATE TO COAL COSTS

Q. Does the TAM Reply Update include any changes to delivered price per ton of coal, consumed volume, or fuel cost when compared to the 2024 TAM Initial Filing?

A. Yes. The following tables compare the values from the 2024 TAM Reply Update to the 2024 TAM Initial Filing. Confidential Table 1 shows updates and variance for the delivered prices per ton from each supplier:[1]

[1] The 2024 TAM Reply and 2024 TAM Direct values in the tables below are rounded for display purposes, but the underlying calculations for variances and totals are not based on the rounded display values.

REDACTED

Confidential Table 1

Delivered Price per Ton of Coal						
Plant	**Supplier**	**2024 TAM Reply**	**2024 TAM Direct**	**Variance-$**	**Variance-%**	**Variance Explanation**
Colstrip	Westmoreland/Rosebud	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Craig	Trapper Mining Inc	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Dave Johnston	Peabody/NARM	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Dave Johnston	Peabody/Caballo	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Dave Johnston	Unspecified PRB Mines	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Dave Johnston	Eagle Butte	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hayden	Peabody/Twentymile	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hunter	Wolverine/Sufco, Skyline	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hunter	Bronco/Emery	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hunter	Gentry Mountain	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Huntington	Wolverine/Sufco, Skyline	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Jim Bridger	Bridger Coal Company	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Jim Bridger	Unspecified PRB Mines	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Naughton	Kemmerer Operations	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Wyodak	Black Hills/Wyodak	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Confidential Table 2 compares the tons of coal consumed:

Confidential Table 2

Consumed Volume (tons, millions)				
Plant	**2024 TAM Reply**	**2024 TAM Direct**	**Variance-$**	**Variance-%**
Colstrip	[redacted]	[redacted]	[redacted]	[redacted]
Craig	[redacted]	[redacted]	[redacted]	[redacted]
Dave Johnston	[redacted]	[redacted]	[redacted]	[redacted]
Hayden	[redacted]	[redacted]	[redacted]	[redacted]
Hunter	[redacted]	[redacted]	[redacted]	[redacted]
Huntington	[redacted]	[redacted]	[redacted]	[redacted]
Jim Bridger	[redacted]	[redacted]	[redacted]	[redacted]
Naughton	[redacted]	[redacted]	[redacted]	[redacted]
Wyodak	[redacted]	[redacted]	[redacted]	[redacted]
Total	11.9	10.9	1.0	9%

Confidential Table 3 details the changes to total coal fuel costs:

Confidential Table 3

Fuel Cost ($, millions)				
Plant	**2024 TAM Reply**	**2024 TAM Direct**	**Variance-$**	**Variance-%**
Colstrip	[redacted]	[redacted]	[redacted]	[redacted]
Craig	[redacted]	[redacted]	[redacted]	[redacted]
Dave Johnston	[redacted]	[redacted]	[redacted]	[redacted]
Hayden	[redacted]	[redacted]	[redacted]	[redacted]
Hunter	[redacted]	[redacted]	[redacted]	[redacted]
Huntington	[redacted]	[redacted]	[redacted]	[redacted]
Jim Bridger	[redacted]	[redacted]	[redacted]	[redacted]
Naughton	[redacted]	[redacted]	[redacted]	[redacted]
Wyodak	[redacted]	[redacted]	[redacted]	[redacted]
Total	538.0	547.3	(9.4)	(2%)

Total fuel costs have decreased by $9.4 million in the Reply Update, driven primarily by a higher percentage of Jim Bridger plant coal supply being incremental coal from Bridger Coal Company (BCC) and coal sourced from the Powder River Basin.

Confidential Table 4 summarizes the CSAs in effect for 2024 as of the filing of this Reply Update:

Confidential Table 4

[redacted]

III. HUNTER CSAs

Q. In their opening testimony, do any parties raise concerns or adjustments related to new and amended CSAs for the Hunter plant?

A. Yes. Staff witness Rose Anderson raises some questions and concerns about the new and amended Hunter CSAs which she asks the Company to address in reply testimony.[2] Sierra Club challenges the need, cost, and modeling of the new and amended Hunter CSAs and proposes to disallow the costs of the Hunter/Gentry CSA, claiming that "other options were available at lower prices."[3]

Q. Has PacifiCorp executed any new CSAs since its Initial Filing in the 2024 TAM?

A. Yes. PacifiCorp entered into the Hunter/Wolverine CSA on June 23, 2023. Consistent with the requirements set in previous TAM orders,[4] Highly Confidential

[2] Staff/400, Anderson/8.
[3] Sierra Club/100, Burgess and Roumpani/41.
[4] *In the Matter of PacifiCorp, dba Pacific Power, 2023 Transition Adjustment Mechanism*, Docket No. UE 400, Order No. 22-389 at 4–6 (Oct. 25, 2022); *In the Matter of PacifiCorp, dba Pacific Power, 2022 Transition Adjustment Mechanism*, Docket No. UE 390, Order No. 21-379 at 6–7 (Nov. 1, 2021).

Exhibit PAC/501 contains an overview and background of the Hunter/Wolverine CSA and the economic analysis supporting this CSA. This exhibit supports the prudence of the Hunter/Wolverine CSA and demonstrates how PacifiCorp incorporated integrated resource plan-type planning and modeling into the decision process relating to the CSA.

Q. What are the terms of the new and amended CSAs at Hunter?

A. The term of the Hunter/Wolverine CSA is [redacted] The Hunter/Bronco CSA Third Amendment has [redacted] The Hunter/Gentry CSA was [redacted] with a term of [redacted] All three CSAs are consistent with PacifiCorp's current practice of limiting long-term CSAs where practical, based on business judgment, to maintain flexibility in fuel supply and generation planning. PacifiCorp continually re-evaluates this practice and its impact on customers.

Q. What is the annual volume and pricing for the new and amended Hunter CSAs?

A. The annual volume and pricing for the Hunter/Bronco CSA Third Amendment and Hunter/Gentry CSA are unchanged from that set forth in my direct testimony.[5]

Annual volume and pricing for the Hunter/Wolverine CSA is as follows:

Year	Volume	Price/Ton
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

[5] PAC/200, Owen/17.

Q. Did the Company supplement its Initial Filing in this case with analysis of the Hunter/Bronco CSA Third Amendment for the Hunter plant?

A. Yes. The Company executed the Third Amendment to the Hunter/Bronco CSA just shortly before it filed the 2024 TAM, so it was unable to include all the supporting documentation in the Initial Filing. On May 8, 2023, the Company supplemented its Initial Filing with its analysis of the Hunter/Bronco CSA Third Amendment. In accordance with the Commission's direction in the 2023 TAM, these materials were filed 45 days in advance of the filing date for Staff and intervenor opening testimony. I am responsible for the development and presentation of this documentation and analysis, and incorporate this supplemental filing by reference into my reply testimony.

Q. In opening testimony, Staff witness Anderson states that the Company provided no supporting analysis for the third Hunter/Bronco CSA Amendment.[6] Please clarify.

A. As noted above, the Company provided this information for the third Hunter/Bronco CSA amendment though a supplemental filing on May 8, 2023. I provided the analysis for the second Hunter/Bronco CSA amendment in my direct testimony as Highly Confidential Exhibit PAC/204.

Q. Did the Company include its analysis of the Hunter/Gentry CSA in your direct testimony?

A. Yes. My direct testimony describes the Hunter/Gentry CSA[7] and sponsors the CSA analysis in Highly Confidential Exhibit PAC/201**.**

[6] Staff/400, Anderson/4–5.
[7] PAC/200, Owen/14–15.

Q. Do the new and amended Hunter CSAs include minimum take requirements?

A. Yes. All the Hunter CSAs are take-or-pay agreements, meaning that PacifiCorp is obligated to purchase the negotiated minimum amount under each contract. I have discussed the prudence of minimum take requirements at length in previous TAM testimony.[8] PacifiCorp could not have obtained the Hunter CSAs without take-or-pay provisions, especially given the severe coal supply constraints and demand increases in the Utah coal market. As a practical matter, these provisions are low risk because: (1) the coal volumes under contract for Hunter are less than what is required to meet Hunter's projected generation forecast and to restock its coal piles to optimum levels; and (2) [redacted].

Q. Please summarize the Company's fuel supply for the Hunter plant for 2024-2025.

A. The Company now has three CSAs in place to supply coal to the Hunter plant in 2024-2025: the Hunter/Wolverine CSA, the Hunter/Bronco CSA Third Amendment, and the Hunter/Gentry CSA. The total amount under contract for 2024 is [redacted] tons (Hunter/Wolverine – [redacted] tons; Bronco/Hunter Third Amendment – [redacted] tons; Hunter/Gentry – [redacted] tons). These volumes are [redacted] than the actual coal consumed at Hunter in 2022, which was [redacted] tons which also included a significant portion of the available stockpiled inventory. Given continued coal supply challenges in the Utah coal market, as well as Hunter's depleted coal stockpiles, the TAM Reply Update [redacted]

[8] *In the Matter of PacifiCorp dba Pacific Power's 2023 Transition Adjustment Mechanism*, Docket No. UE 400, PAC/200, Owen/6 (Mar. 1, 2022).

[redacted]. Specifically, the Company has included the Hunter/Bronco CSA Third Amendment at [redacted] in the Reply Update and forecasts a total of [redacted] tons of coal for Hunter in 2024. The [redacted]. This is discussed further in my testimony below.

Q. Staff witness Anderson expresses concern about the [redacted] in the Hunter CSAs. She testifies that Staff is reviewing if the Company fully studied the price changes and whether the new CSAs are beneficial to customers.[9] Please respond.

A. The price changes in the new and amended Hunter CSAs must be viewed in the context of the unprecedented volatility in the coal markets since 2021. As I explained in my direct testimony, the combination of historically low coal inventories and soaring natural gas prices led many utilities and other coal consumers to revert back to coal use and increase coal purchases for both consumption and to restock depleted coal inventories. In many coal basins, coal pricing more than doubled and remained high throughout much of 2022. This is especially true in coal basins with supply constraints, such as Utah's. Utah mines are relatively old and face significant geological challenges in accessing and extracting remaining reserves. In early 2022, this situation was exacerbated by the Russian invasion of Ukraine, which led to natural gas supply decreases and price increases. European markets responded by reverting to the use of coal, which resulted in record-high European coal prices in

[9] Staff/400, Anderson/4.

early 2022. The price of natural gas and coal in U.S. markets correspondingly increased. U.S. coal price increases followed natural gas prices, with a four-to-six-month delay based on coal suppliers' access to export markets. U.S. mines, including mines in Utah and Colorado, rushed to take advantage of record high coal prices by exporting coal to Europe, or by leveraging increased prices in the domestic market. The September 2022 Lila Canyon mine fire further compounded the supply and demand imbalance in the Utah coal market. As natural gas prices dropped in late 2022, coal prices in some regions began leveling off. As demonstrated in the figures below, however, prices in the Utah and Colorado coal markets remain approximately double 2021 levels, even with the drop in natural gas prices.

Figure 1. Price Changes in Western Coal Markets 2021-2023

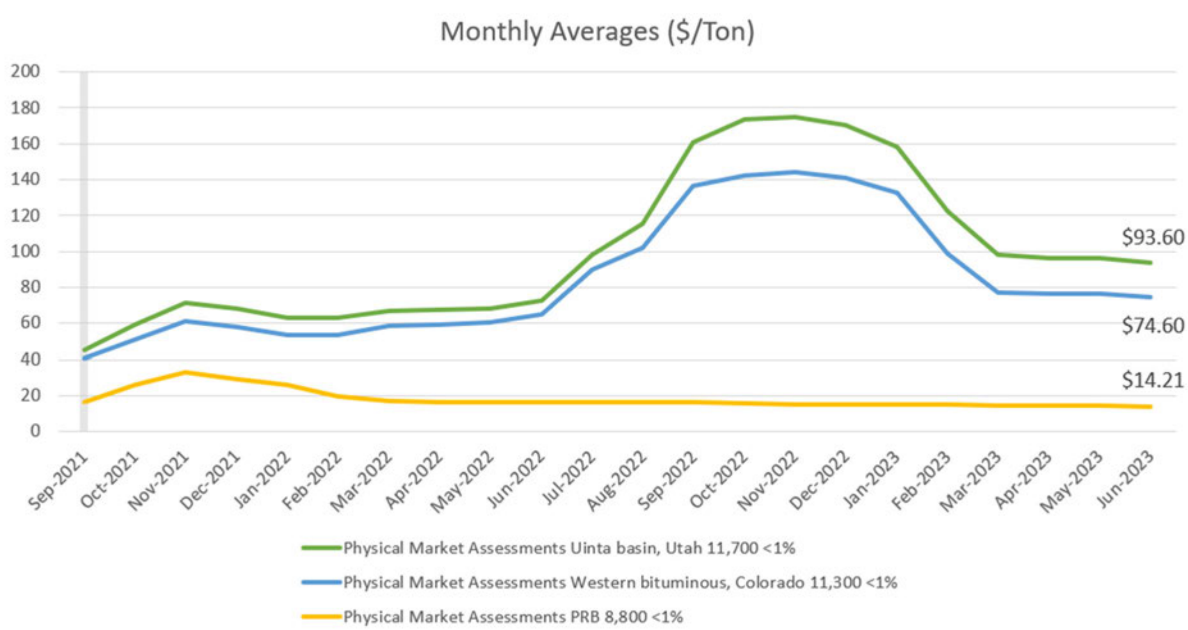
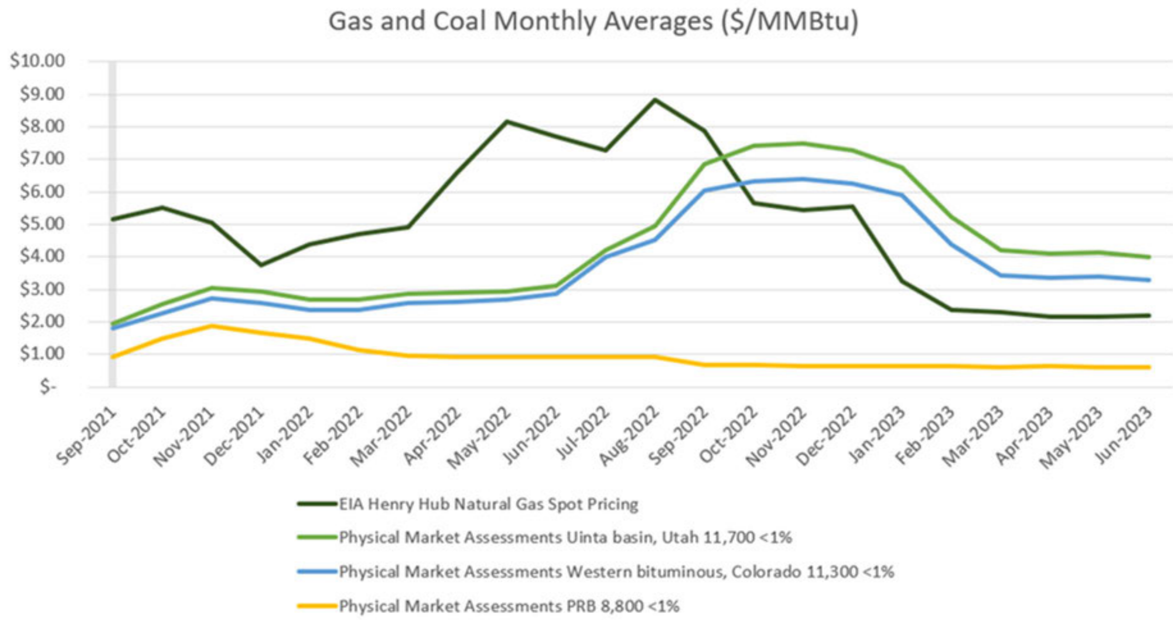


Figure 2. Price Changes in Western Coal and Natural Gas Markets 2021-2023



Q. In your direct testimony, you explained that the Company acquired the CSAs at Hunter through a request for proposals (RFP) issued in September 2022. Do the RFP results assist to demonstrate the prudence of the Hunter CSAs, [redacted]?

A. Yes. The Company issued the 2022 RFP to identify all potential and reasonable sources of coal supply for the Hunter plant. The 2022 RFP results demonstrate both the limited availability and significant price increases in the current market for the shorter-term CSAs for which Staff continues to advocate. [redacted], however, the Company's economic analysis demonstrates that each of the Hunter CSAs is cost-effective. Indeed, Staff acknowledges that Hunter is economically dispatching in the TAM at the [redacted] prices in the new CSAs and, if the Company could acquire additional coal at these prices and increase Hunter's dispatch, it would likely reduce 2024 net power costs (NPC).[10]

Q. Staff raises the issue of the force majeure claims from Utah coal suppliers and indicates that it is reviewing the actions PacifiCorp took in response to manage cost and risk for customers. Can you address this issue?

A. Yes. The Company received a force majeure claim from Bronco Utah Operations, LLC on June 22, 2022, for its CSA at Hunter. [redacted]. As described in my direct testimony and in the analysis provided in the Company's supplemental filing, the Company challenged Bronco's force majeure claim as invalid, and notified Bronco it was in breach of its contract obligations, which initiated arbitration processes. During this time the Company continued to negotiate changes to the Bronco CSA while maintaining coal supply and supplier coal operations for Hunter. [redacted]

[10] Staff/400, Anderson/5, 8.

[redacted]

Wolverine Fuels, LLC asserted force majeure claims on September 22, 2022, for its CSAs at Hunter and Huntington. These claims were based on Wolverine's [redacted] The Company has also maintained communication directly with the Lila Canyon mine to confirm information relating to the mine fire and its impacts.

The data provided in Confidential Table 5 details the impact of the force majeure claims on total 2022 coal deliveries at the Hunter and Huntington plants.

Confidential Table 5: 2022 Hunter and Huntington Plants Coal Supply

Plant	Supplier	Tons Under Contract	Tons Delivered	Variance	Explanation
Hunter	Wolverine	[redacted]	1,831,679	[redacted]	
	Bronco		727,689		
	Other		14,343	14,343	
		[redacted]	2,573,711	[redacted]	
Huntington	Wolverine	[redacted]	1,966,980	[redacted]	
Total		[redacted]	4,540,691	[redacted]	

Q. What steps did the Company take to manage the shortfalls in coal deliveries caused by the force majeure claims?

A. PacifiCorp evaluated the merits of the force majeure claims and considered the legal options available to it under its CSAs. The Company immediately began transporting coal from the Rock Garden safety pile for consumption at the Huntington plant to compensate for reduced coal deliveries. The Company also began working with current suppliers on potential solutions and new potential Utah coal suppliers to secure additional coal, and began exploring alternative coal sources, leading to the RFP. The Company also initiated evaluations for (and continues to evaluate) potential acquisition of coal sourced from outside of Utah. In addition, PacifiCorp began reducing generation at the Hunter plant in September 2022 and at the Huntington plant in November 2022 to maintain the stockpile reliability target of [redacted] inventory. Based upon industry standard practice regarding the dispatch of fuel-limited resources, such as hydro, PacifiCorp calculated the dispatch price for the fuel-limited Hunter and Huntington units to maintain minimum coal stockpile inventories and secure plant availability for the benefit of customers during critical periods.

Q. Staff requests that the Company explain whether it took steps to attempt to improve contract flexibility in the wake of the force majeure claims, such as renegotiating the duration of the Huntington CSA or the ability to use coal interchangeably at the Hunter and Huntington plants.[11]

A. The Company is always focused on achieving its target coal supply at a reasonable price, along with contract terms that provide flexibility. In Utah's current supply-constrained market, however, the Company has limited leverage to accomplish these goals. [redacted] Nevertheless, as Staff acknowledges, the Company was able to obtain flexibility in the Hunter/Bronco CSA Third Amendment, including its [redacted]. In the Hunter/Wolverine CSA, [redacted].

As for the Huntington CSA, Wolverine's force majeure claim is [redacted]

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[11] Staff/400, Anderson/7.

[redacted].

Q. Staff notes that the Company accomplished flexibility in the Wyodak CSA by omitting a minimum take agreement.[12] Please comment.

A. It is important to note that the CSA for the Wyodak plant is a "requirements" contract, meaning that PacifiCorp agreed to purchase 100 percent of the coal that PacifiCorp will consume at the Wyodak plant during the term from the coal supplier. Thus, the Wyodak contract does have a requirement to purchase coal, but the parties did not specify a particular minimum or maximum volume and acknowledge that it will vary based on future power market conditions. Essentially the requirements agreement allows the Company to secure coal supply for Wyodak from a specific supplier without committing to any particular volume. In exchange, the coal supplier gets a guarantee that any coal needed will be purchased from them. In this case, the coal supplier owns 20 percent of the plant and can estimate PacifiCorp's future consumption based on nearly 50 years of affiliation with the plant.

[12] Staff/400, Anderson/6. Sierra Club makes a similar point at Sierra Club/100, Burgess and Roumpani/14. Sierra Club also claims that Craig is supplied by an affiliate mine and is not subject to a minimum take provision. See Sierra Club/100, Burgess and Roumpani/14. This is incorrect. The Trapper mine is an affiliated mine (PacifiCorp owns 29.14 percent) and the coal supply agreement with Trapper does have a minimum take requirement.

Q. Staff testifies that the increased Hunter CSA prices suggest that the Utah coal suppliers are exercising monopoly power.[13] Staff also asks the Company to comment on whether it can exercise monopsony power in determining the market price for potential additional coal at Hunter.[14] Please respond.

A. In this and previous cases, the Company has explained the challenging dynamics of the coal industry, where the large capital requirements of mining, the costs of coal transportation, and coal quality variations result in a non-centralized, non-liquid market. In such a market, supply and demand imbalances can lead to coal unavailability and price hikes irrespective of the market power of individual suppliers or purchasers. The Company has historically insulated itself against supply shortages and market fluctuations in non-liquid coal markets through CSAs with fixed pricing and reasonable terms to mitigate the risks of price hikes. This can be seen in the Company's situation at Huntington where, despite Wolverine's force majeure claim related to the coal supply from the Lila Canyon mine, the Company is still able to access approximately [redacted] of Huntington's minimum coal supply in 2024 at approximately $[redacted]/ton under the long-term CSA, compared to $[redacted]/ton for coal under the new and amended shorter-term Hunter CSAs. The price increases in the Utah market cannot simply be categorized as the result of coal mines exercising monopoly power. This is true for a number of reasons: (1) the Utah coal mining companies are genuine competitors and do not cooperate or collude during CSA negotiations with the Company; (2) the practice of limiting contract length will inherently make the Company more subject to market fluctuation; (3) the Utah coal

[13] Staff/400, Anderson/4.
[14] Staff/400, Anderson/8.

market is not insulated from the volatility of broader domestic and international coal markets; (4) the Company's extensive portfolio creates inherent competition between Utah coal and other potential system resources, including natural gas generation, renewable generation, or even market purchases. The Company also cannot exercise true monopsony power in the Utah coal market because there are multiple buyers competing for Utah-produced coal, including international customers, other in-state and out-of-state power plants, and in-state industrial coal users.

Q. Staff indicates that it is reviewing whether the Company has utilized the full flexibility of its coal contracts, coal piles, and mines outside of Utah to address the coal supply issues in the Utah market. Has the Company explored all available supply options for Hunter?

A. Yes. First, the Hunter plant has historically relied on coal sourced from nearby mines, and the transportation of coal has been efficiently facilitated through trucking. Thus, Hunter currently lacks rail infrastructure for receiving coal from other coal basins by rail. This lack of adequate off-loading rail infrastructure limits PacifiCorp's ability to procure and receive coal from outside of the state of Utah.

Second, notwithstanding this limitation, the Company invited coal and transportation suppliers from outside of Utah to participate in the RFP to explore the feasibility of alternative supply options. [redacted] In addition, none of the Company's own mines can cost-effectively supply the Hunter plant.

Third, the Company collaborated with a co-owner of the Hunter plant to acquire additional coal from one of their mines.

Fourth, as explained above, the Company has used its coal piles to mitigate the coal supply shortfalls and reduced plant dispatch as necessary to maintain reliable coal inventory levels.

Fifth, the Company is working with several non-conventional coal sources, including evaluating coal previously categorized as refuse, to supplement the fuel supply and continues to look for innovative ways to increase Hunter's fuel supply.

Q. Staff suggests that the Company may have the ability to obtain additional coal under the Hunter/Bronco CSA Third Amendment and, if this is true, the value of this additional coal supply should be reflected in the TAM.[15] Does the Company expect to receive coal in excess of the base amount under the amended Bronco CSA?

A. [redacted].

Q. Staff asks the Company to address whether (1) PacifiCorp is required to take coal in excess of [redacted] tons under the Bronco CSA Third Amendment in 2024, and (2) the NPC reduction associated with additional supply to the Hunter plant.[16] Please respond to each.

A. First, [redacted]

[15] Staff/400, Anderson/7–8.
[16] Staff/400, Anderson/8.

[redacted] The amount of coal under contract with Bronco is [redacted] tons for 2023 and [redacted] tons for 2024. Any coal available in excess of [redacted] tons up to [redacted] tons ([redacted] tons) would be offered by Bronco for purchase by the Company [redacted]. The Company has the option to purchase the [redacted] and would evaluate the benefits based on [redacted] prior to purchase. Second, PacifiCorp cannot quantify the impact of additional purchases on NPC at this time; the Company would need to evaluate the costs and benefits based upon the price, market conditions, and other factors if and when additional coal becomes available.

Q. Sierra Club challenges the Company's analysis and selection of the Hunter/Gentry CSA in the RFP, claiming that another bid was lower cost.[17] Is this accurate?

A. No. The bid that Sierra Club suggests was lower cost, Bid 7, was an alternative to another bid, Bid 8, with the bidder, [redacted] requiring the Company to select either Bid 7 or Bid 8. The Company could not select both. Bid 8 provided substantially more coal supply and the Company selected it, [redacted]. This foreclosed the Company's ability to pursue Bid 7, so the Company turned to Bid 1, which resulted in the Hunter/Gentry CSA.

Q. Sierra Club also challenges the economic analysis the Company conducted of the Hunter/Gentry CSA, claiming first that the analysis was not properly documented.[18] Please respond.

A. The Company provided the results of its PLEXOS modeling of the RFP bids, along

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[17] Sierra Club/100, Burgess and Roumpani/40.
[18] Sierra Club/100, Burgess and Roumpani/37.

with supporting workpapers. The analysis and documentation is comparable and technically equivalent to the analysis the Company has provided for other CSAs. If Sierra Club requests more specific or granular data, the Company is willing to review such a request.

Q. Sierra Club claims that the Company's analysis assumed greater demand at the Hunter plant than that reflected in the TAM or in the average cost run results. Sierra Club argues that the Hunter/Gentry CSA is unnecessary under more reasonable demand assumptions.[19] Is this accurate?

A. No. The Hunter/Gentry CSA analysis does not use an "inflated demand" as claimed by Sierra Club. The Hunter coal demand reflected in the TAM was simply limited to only the expected coal supply available during 2024. Therefore, the results do not represent the true demand for Hunter coal supply. The assumed coal demand in the TAM is derived using the Aurora model software with normalized inputs and assumptions as required by the Commission for a regulatory filing in Oregon. The assumed demand at Hunter reflected in the Hunter/Gentry CSA analysis was derived using the PLEXOS model software, which is consistent with the Integrated Resource Plan (IRP), and uses different inputs and assumptions than the TAM. The TAM model and Hunter/Gentry CSA model were also prepared approximately six months apart using different forward price curves, OTR compliance assumptions, coal contracts, and system resources. Additionally, as explained in Highly Confidential Exhibit PAC/201, the analysis in PLEXOS was prepared using a range of low, expected, and high cases of demand. Even under the low demand case, the

[19] Sierra Club/100, Burgess and Roumpani/37.

Hunter/Gentry CSA provided benefits.

Q. Next, Sierra Club claims that the modeled price for the Hunter/Gentry CSA in the Initial Filing is different than what is reflected in the workpapers.[20] Please address this discrepancy.

A. In the Initial Filing of the 2024 TAM, the Company inadvertently modeled the incorrect price for the Gentry/Hunter CSA. The [redacted]/ton amount modeled in Aurora and reflected in Highly Confidential Exhibit PAC/200 Owen/23 was incorrect. The price has been updated in the reply filing to reflect the correct pricing from the CSA for 2024. The [redacted]/ton amount shown at Highly Confidential Exhibit PAC/200, Owen/15 and Highly Confidential Exhibit PAC/201, Owen/2 is the correct price and is also the price that was used in PLEXOS for the Hunter/Gentry CSA analysis.

Q. Lastly, Sierra Club claims that the Company's analysis shows that the Hunter/Gentry CSA may not be beneficial for customers, and the Company failed to fully consider other RFP bids.[21] Is this true?

A. No. As explained above, the Hunter/Gentry CSA provided benefits to PacifiCorp customers under a range of potential generation demand conditions at Hunter.

Q. Sierra Club also challenges the modeling of the minimum take requirements of the Hunter CSAs since the Commission has not yet reviewed the prudence of these agreements.[22] Has the Company appropriately modeled these CSAs?

A. Yes. PacifiCorp witness Mitchell addresses the modeling of new CSAs in his

[20] Sierra Club/100, Burgess and Roumpani/37.
[21] Sierra Club/100, Burgess and Roumpani/37.
[22] Sierra Club/100, Burgess and Roumpani/41.

testimony. I address the need for the take-or-pay provisions of the CSAs in both my direct testimony and in my reply testimony. Indeed, Sierra Club acknowledges that minimum take provisions are practical.[23] Suffice it to say, the Company could not have obtained these CSAs without a minimum take agreement, and the Hunter plant is meeting these contract minimums through normal economic dispatch.

IV. OZONE TRANSPORT RULE

Q. Several parties have raised adjustments or concerns about OTR-related costs in the Company's Initial Filing. Please provide a brief explanation of the OTR.

A. OTR is the Environmental Protection Agency's (EPA) finalized federal plan for interstate transport of the 2015 ozone National Ambient Air Quality Standards and has an effective date of August 4, 2023. The plan applies to 23 states, including Utah, and includes requirements to eliminate significant contributions of ozone or ozone precursors (specifically, nitrogen oxides (NOx)) to nonattainment or maintenance areas in neighboring states. With respect to fossil fuel-fired electric generating units, the final rule implements an allowance-based trading program where each unit is allocated a portion of the state's NOx budget during the ozone season (identified in the rule as May 1 – September 30).

Q. Please explain how NOx allowances are determined at the state and electric generating unit level under OTR.

State budgets and unit allocations are pre-set by the EPA for the 2023 through 2025 ozone seasons. State budgets are also pre-set from 2026 through 2029, unless the dynamic budget is greater than the EPA's set budgets, then the dynamic state budget

[23] Sierra Club/100, Burgess and Roumpani/14.

is used in place of the pre-set budget. Starting in 2030 and beyond, state budgets will be dynamic. Dynamic budgets are calculated using data reported for the most recent three-year historical heat input data available at the time of the calculations (e.g., to calculate dynamic state budgets for the 2026 control period, the EPA will use reported data from 2022 through 2024), multiplied by the EPA's assumed NOx emission rate, which is set based on emission control equipment requirements for the control period. All electric generating units' NOx tons are summed to determine the state budget.

Once the state budget is calculated, the unit allocations are derived by averaging the unit's three highest, non-zero ozone season heat input values within the five-year baseline period (e.g., to calculate allocations for the 2026 control period, the EPA will use reported data from 2020 through 2024). Each unit's three-year average heat input is divided by the state's total three-year average heat input to determine that unit's share of the state's total three-year average heat input. Each unit's share of the state's total three-year average heat input is then multiplied by the existing-unit portion of the state emissions budget (i.e., the state budget less the state's new unit set-asides) to determine that unit's tentative heat input-based allocation.

For each unit, the maximum ozone season NOx emissions value from the five-year baseline period for the unit is identified and serves as a cap on unit allocations. These values are referred to as the "maximum total NOx emissions value" for each unit. Additionally, starting in 2024 for coal-fired units with existing selective catalytic reduction controls, and starting in 2027 for other coal-fired units of 100 megawatts or larger, a "maximum controlled baseline" is calculated for each such unit by multiplying the unit's maximum ozone season heat input from the five-year baseline period, times a NOx emissions rate of 0.08 pounds per million British thermal units. The lower of the unit's "maximum total NOx emissions value" or, where applicable, the unit's "maximum controlled baseline" is the unit's tentative allocation cap.

Q. Please explain EPA's OTR assurance provisions.

A. EPA included assurance provisions in the finalized OTR rule, which limit state emissions to levels below 121 percent of the state's budget by requiring additional allowance surrenders if a state's emissions exceed the state assurance level. If a state exceeds its assurance level, EPA will look at which units in the state exceeded their unit assurance level, and ultimately, contributed to the state's assurance level exceedance. If a unit is found to contribute to the state's exceedance, then the unit must surrender the appropriate additional allowances.

Q. Please explain how NOx allowances can be used and/or transferred under OTR.

A. Each generating unit has an allowance account where NOx allocations and/or transferred allowances are held, which is designated with a unique account number. Each account has a Designated Representative (DR), Alternative DR, and/or agent(s) that are legally responsible for the account. In July following the end of the ozone season, EPA withdraws allowances equal to the amount of emissions during the previous ozone season from each account. An owner of multiple units may transfer allocated allowances among those units as long as the group of units are represented by a common DR and are in the same trading group program. Allowances can also be sold and purchased with others participating in the same trading group program.

Q. Please provide a brief description of the Company's strategy to maintain compliance with the OTR.

A. PacifiCorp has already started altering power purchases and energy-sale plans, developing compliance and monitoring and reporting systems, and procuring retrofit equipment (selective non-catalytic reduction systems) to comply with the OTR. PacifiCorp will also adjust dispatch of its thermal generation units subject to OTR as necessary to ensure there are sufficient NOx allowances to cover that generation.

Q. CUB witness Bob Jenks raises a concern regarding the interaction of the OTR and minimum take provisions in the Company's CSAs, suggesting that OTR-based reductions in generation could lead to PacifiCorp incurring additional costs under its CSAs.[24] Can you address how PacifiCorp considers the OTR in evaluating new and amended CSAs?

A. Yes. OTR assumptions, restrictions and conditions are modeled in Aurora for the TAM and in PLEXOS for the evaluation of new coal contracts using the best available information. Forecast generation and fuel requirements are reduced as necessary for expected operation of the units in order to comply with OTR limits. These impacts are holistically considered in setting CSA minimum take levels. OTR restrictions become significantly more stringent beginning in 2026. Consequently, the Company has refrained from signing new CSAs for 2026 and beyond for certain plants (Hunter, Dave Johnston, and Jim Bridger) until the impacts of OTR become more certain. This strategy will be continuously re-evaluated and may be adjusted as legal processes concerning OTR develop. The Company has also incorporated

[24] CUB/100, Jenks/11.

provisions in new and amended CSAs to provide additional flexibility if the Company's ability to meet its obligations under the CSAs are impacted by OTR.

Q. CUB, AWEC, and Vitesse question whether the Company correctly modeled application of the OTR to Wyoming in 2024.[25] Please respond.

A. EPA included Wyoming in its federal OTR proposal but deferred its final decision on whether to deny Wyoming's OTR state plan until December 15, 2023. EPA must make a final determination disapproving Wyoming's state plan before it would have authority to impose its federal OTR plan. It is uncertain whether EPA will approve or disapprove Wyoming's state plan. Despite EPA's deferral, it is prudent to model OTR application in Wyoming in 2024.

EPA has had multiple opportunities and ample justification to exclude Wyoming from OTR, indeed the Company is actively advocating for it to be excluded, but EPA has not opted to do so. One key factor in determining whether a state is subject to the federal OTR plan is if EPA's air dispersion modeling shows the state contributes 0.7 parts per billion (ppb) or more to downwind air monitors in other states. EPA's modeling indicated Wyoming's cross-state contribution at 0.68 ppb. Based on EPA's own modeling methodology Wyoming does not meet the standard for inclusion in the rule. However, even with this evidence, EPA included Wyoming in its initial federal proposal and did not approve Wyoming's state plan. When EPA was challenged on its decision to include Wyoming, the agency did not relent, but simply deferred its decision stating more evaluation was needed, including a new round of notice and public comment, where additional evidence could be

[25] CUB/100, Jenks/11; Vitesse/100, Johnson/28–29; AWEC/100, Mullins/15.

introduced. Given EPA's unwillingness to approve the state plan in spite of the record before it; EPA's previous proposal to include Wyoming in its federal plan; and the level of uncertainty around EPA's final determination, it would not be prudent of the Company to exclude OTR in Wyoming in 2024 until EPA has finalized their decision.

In his reply testimony, Company witness Ramon Mitchell addresses how the Company has revised its OTR modeling in the Reply Update to account for the final OTR rule, which was published in the federal register on June 5, 2023, after the Initial Filing. Under the final rule, the Company can share NOx limits across the Company's generation fleet. However, continued coal supply and other economic restraints are the limiting factors for Utah units, as opposed to OTR NOx limits in 2023 and 2024. NOx allocations can be utilized at other units, such as the Company's Wyoming generating units.

Q. CUB claims that OTR restrictions on coal plant dispatch were foreseeable and customers should be held harmless if minimum take provisions can no longer be met.[26] Please respond.

A. The Company disagrees that the full extent of OTR impacts on dispatch was reasonably foreseeable before the rule was finalized and the Company had conducted modeling. In the Initial Filing, all units consumed above their minimum contractual volume, except Hunter and Huntington, which were adjusted downward to reflect coal supply shortfalls associated with the force majeure claims. CUB asserts a hypothetical but unfounded concern because, among many other reasons, OTR does

[26] CUB/100, Jenks/11–12.

not cause any of the Company's units to dispatch below their contractual minimums in the 2024 TAM.

V. JIM BRIDGER PLANT FUEL SUPPLY

Q. Please provide a brief overview of the Company's 2023 Fuel Plan.

A. PacifiCorp filed its 2023 Fuel Plan in docket LC 82 on May 31, 2023, as directed by the Commission. The 2023 Fuel Plan refines the Company's 2022 Fuel Plan, which was preliminary and filed in the 2023 TAM. The 2023 Fuel Plan evaluates how PacifiCorp can best meet the fueling needs of the Jim Bridger plant throughout the operational life of the plant, given the natural gas conversion of Jim Bridger Units 1 and 2 in 2024, reductions to coal generation as a result of increased renewable generation in the Company's portfolio, OTR, and other changing circumstances affecting the plant over the next several years. A copy of the 2023 Fuel Plan is included as Highly Confidential Exhibit PAC/502.

Q. Did PacifiCorp file the 2023 Fuel Plan filed in conjunction with PacifiCorp's 2023 IRP?

A. Yes. Through deliberations in the 2021 IRP proceeding in Oregon (docket LC 77), PacifiCorp agreed to complete a revised long-term fuel plan and include the plan details as assumptions aligned with or as a part of the 2023 IRP. The Company used the pricing assumptions and mine plan options developed for the 2023 Fuel Plan in the 2023 IRP. In turn, the resource mix selected in the 2023 IRP then informed the 2023 Fuel Plan. Going forward, the Company will prepare an updated long-term fueling plan for the Jim Bridger plant every two years in conjunction with its biennial IRP, as directed by the Commission.

Q. As background, has the Commission previously addressed the Company's fueling strategy for the Jim Bridger plant in the TAM?

A. Yes. Issues regarding PacifiCorp's fueling strategy for the Jim Bridger plant have been raised multiple times over the years, including in the dockets UE 264 (2014 TAM), UE 307 (2017 TAM), UE 323 (2018 TAM), UE 339 (2019 TAM), UE 356 (2020 TAM), and UE 390 (2022 TAM). The Commission has repeatedly affirmed the reasonableness of the Company's strategy for fueling the Jim Bridger plant.

Q. How did the Company develop the 2023 Fuel Plan?

A. PacifiCorp followed its past practice and studied, reviewed, and evaluated different possible, reasonable, and practical fueling options for the Jim Bridger plant. This includes review of various mines and mining companies, transportation options, and coal quality evaluations. The Company also considers its own mining operations and various mine plans.

Q. What specific fueling options did the Company evaluate in the 2023 Fuel Plan?

A. The fueling options PacifiCorp considered feature varying delivery schedules sourced from the Company's Bridger mine, operated by BCC, the Black Butte mine, and mines located in Wyoming's Southern Powder River Basin (SPRB). Additionally, the different coal delivery options for the Bridger mine contain various mine plan scenarios outlining specified delivery schedules. Included in these different mine scenarios are estimated dates for the Bridger mine to cease production.

The Company developed and evaluated six primary Jim Bridger plant coal fueling options:

- **Scenario 1** [redacted]
- **Scenario 2** [redacted]
- **Scenario 3** [redacted]
- **Scenario 4** [redacted]
- **Scenario 5** [redacted]
- **Scenario 6** [redacted]

Q. Why do each of the six scenarios assume PacifiCorp [redacted]?

A. PacifiCorp will operate all four Jim Bridger units on coal until the end of 2023, when Units 1 and 2 will cease operating on coal and will be converted to natural gas operation. Use of coal from Black Butte is necessary to ensure adequate coal supply while all four units are operating. [redacted]

[redacted] The current Black Butte CSA, which was deemed prudent as a part of the stipulation in the 2023 TAM, is effective through the end of 2023.

Q. How did the Company develop its pricing assumptions used in the 2023 Fuel Plan?

A. The 2023 Fuel Plan pricing assumptions were developed following the practice used by the Company for previous iterations of the Fuel Plan. Specifically, the 2023 Fuel Plan provides third-party coal supply volume and pricing estimates based upon indicative pricing received from the Black Butte mine, as well as recent coal pricing forecasts from Energy Ventures Analysis. The 2023 Fuel Plan provides estimated volumes and rail rates for transportation services based on prior agreements between the Company and the Union Pacific Railroad for the transport of coal from third-party coal supply sources. The estimated plant modifications and capital requirements, defined by equipment category, as well as total costs needed to support large volumes of SPRB coal are derived from a detailed third-party study completed in 2017 by the engineering and consulting firm Burns & McDonnell, adjusted for inflation and to account for volumes associated with operating two coal units instead of four coal units. BCC volumes and costs are derived from the most current mine plans.

Q. How did the Company evaluate each of the six scenarios?

A. The Company completed a Present Value Revenue Requirement (PVRR) calculation, comparing major components of PacifiCorp's NPC resulting from the various fueling options, including a composite ranking considering both financial and risk weighting. The costs modeled include coal purchases, natural gas purchases, and system power purchases offset by wholesale power sales. The analysis is based on the Company's forward price curve for power and natural gas, which does not include greenhouse gas costs, but does account for the impacts of certain EPA emissions requirements, such as the OTR.

Q. Is the Company's economic analysis in the 2023 Fuel Plan similar to that used in the 2022 Fuel Plan?

A. Yes. PacifiCorp conducted the economic analysis in the 2022 and 2023 Fuel Plans using a holistic and comprehensive approach. The plan evaluates each fueling option in terms of its impact on major components of PacifiCorp's NPC. Each fueling option's unique cost profile is used in a production software model (GRID for 2022 and PLEXOS for 2023) to derive the generation forecast for all of PacifiCorp's generating plants. The evaluation further considers the impact of each fueling option on power purchases, wholesale sales and other significant components of NPC. The total NPC for each fueling option is then compared on a PVRR basis in PLEXOS, the production software PacifiCorp uses for developing its IRP.

Q. Did the Company's scenario analysis assume a depreciable life through 2029 for Units 1 and 2 of the Jim Bridger plant?

A. Yes. The Oregon depreciable life of PacifiCorp's share of the Jim Bridger plant extends through 2029 for Units 1 and 2 and through 2025 for Units 3 and 4. Other states in PacifiCorp's service territory use differing depreciable lives for different units ranging from 2023 to 2037, based upon PacifiCorp's 2018 depreciation study and other regulatory agreements.

Q. What were the results of the Company's evaluation of the six fueling scenarios?

A. The results of the PVRR analysis and risk evaluation indicate that Scenario 5 and Scenario 6 are the current least-cost, risk-adjusted options. Option 6 was modeled assuming *no* minimum take-or-pay obligations for the Bridger mine or Black Butte. Based on PacifiCorp's evaluation using the PLEXOS model, *all* of the available incremental coal from the Bridger mine would be cost-effective. As a result, the fueling plans in Scenario 5 and Scenario 6 are essentially the same. Therefore, Scenarios 5 and 6 are referred to as the "Preferred Scenario" in the 2023 Fuel Plan.

Q. What are the benefits of pursuing the Preferred Scenario as the long-term fueling strategy for the Jim Bridger plant?

A. The Preferred Scenario provides the least-cost, risk-adjusted fuel supply for the Jim Bridger plant, allows for coal quantity flexibility from Bridger mine, continues to allow moderate quantities of SPRB coal deliveries to the plant, and avoids large plant capital modifications required for a complete SPRB fuel switch. The Preferred Scenario reflects the flexibility and low incremental costs associated with Bridger mine ownership, factors that are particularly beneficial to customers now given the volatility in the electric, natural gas, and coal markets.

Q. In your direct testimony, you explained that the Company had modeled a new, short-term CSA with Black Butte for 2024, subject to further analysis in the 2023 Fuel Plan and 2023 IRP.[27] Now that the 2023 Fuel Plan is complete, can you provide an update on the Company's fuel plan for the Jim Bridger plant in 2024?

A. Yes. Based on the Preferred Scenario, the Company does not expect a new CSA with Black Butte as contemplated in the Company's Initial Filing will be cost-effective. Instead, the Company plans to supply the Jim Bridger plant in 2024 using additional incremental coal from the Bridger mine and coal sourced from the SPRB. This change in coal supply is reflected in the Reply Update and results in a reduction in NPC.

Q. Sierra Club proposes to disallow the costs of the 2024 Black Butte CSA based on the results of the 2023 Fuel Plan.[28] Does the Company's action to implement the Preferred Scenario in 2024 moot this proposed adjustment?

A. Yes. As just explained, the Reply Update does not include a new CSA with Black Butte for 2024, so Sierra Club's adjustment is moot.

Q. Sierra Club also advocates for selection of Scenario 4 in the 2023 Fuel Plan as the Preferred Scenario and proposes that BCC coal be limited to estimates in that scenario.[29] Why did the Company select Scenario 5/6 over Scenario 4 as the least cost-least risk fueling option?

A. As Sierra Club acknowledges, Scenario 5/6 has a PVRR that is $[redacted] million more

[27] PAC/200, Owen/28.
[28] Sierra Club/100, Burgess and Roumpani/20.
[29] Sierra Club/100, Burgess and Roumpani/2.

favorable than Scenario 4's PVRR. While Sierra Club challenges various components that make up this differential,[30] and that differential has been reduced by the modeling error I discuss below, Scenario 5/6 remains the least cost-least risk scenario by over $[redacted] million.[31]

Over the years, customers' rates have included the costs of the Bridger mine. Through this investment, PacifiCorp's customers have effectively purchased and are entitled to benefit from: (i) the option to acquire low-cost Bridger mine incremental production as needed, and (ii) the operational flexibility to prudently increase or decrease production as needed within reasonable operating limits. Sierra Club's recommendations to quickly close the Bridger mine, reduce consumption of low-cost incremental BCC coal, and arbitrarily dispatch the Jim Bridger plant on an average rather than incremental basis, unreasonably deprives customers of the cost-mitigating benefits of Bridger mine ownership at a time when NPC are generally increasing.

Q. Why is it unreasonable to limit BCC coal to the volumes in Scenario 4?

A. Limiting BCC coal volumes to those contained in Scenario 4 would increase NPC and harm customers. Scenario 4 assumes BCC delivers [redacted] tons of coal to Jim Bridger in 2024. Scenarios 5 and 6 assume BCC delivers approximately [redacted] tons of coal to Jim Bridger in 2024. In the 2023 Fuel Plan, [redacted] If BCC coal deliveries were reduced by approximately [redacted] tons, PacifiCorp would need to replace

[30] Sierra Club/100, Burgess and Roumpani/32.

[31] Even after correcting for the error discussed below related to market purchases and sales, the PVRR for Scenario 5/6 is [redacted].

approximately [redacted] megawatt-hours of lost generation with higher cost generation sourced from natural gas (if available), power market purchases or receive less revenue due to reduced wholesale power sales. These options all result in higher NPC and harm customers.

Q. Sierra Club challenges the reasonableness of the BCC coal costs included in the TAM and relies on this argument to support [redacted] Particularly considering current market conditions, are BCC coal costs reasonable?

A. Yes. Sierra Club either fails to understand or chooses to ignore that BCC operating costs are impacted significantly by mine planning assumptions, specifically the operating life of the mine and annual coal production levels. Sierra Club errantly compares the cost of closing BCC in 2023 with calendar year 2023 costs in other scenarios that assume BCC will operate through 2029. Sierra Club fails to recognize that prudently incurred costs for mine investment and reclamation costs are recovered during the mine's operating life. Operating costs will increase when these fixed costs are expensed or funded over a shorter period of time. Additionally, as annual coal production levels decrease, such as assumed in Scenario 4 (BCC's low production scenario), operating costs expressed on a cost per ton basis will increase because these same fixed costs are spread over fewer tons. Scenario 4 represents the minimum prudent operating level at BCC. Operating below this level, which is equivalent to a one dragline operating plan, would result in foregoing lower-cost incremental coal, and would reduce customer benefits from the BCC investment.

[32] Sierra Club/100, Burgess and Roumpani/20–21.

Q. Sierra Club claims that PacifiCorp has a disincentive to reduce coal volumes at BCC, even if this was in the best interest of customers.[33] Is this accurate?

A. No. PacifiCorp's planning processes are specifically designed to determine the least cost, risk-adjusted level of production from BCC. PacifiCorp's interests are best served by operating BCC in the most cost-effective manner possible, which aligns with its customers' interest in maintaining low-cost, reliable service. Sierra Club's allegations to the contrary are speculative and devoid of any evidentiary support.

Q. Please respond to Sierra Club's challenge to the Company's coal pricing assumptions in the 2023 Fuel Plan.

A. Sierra Club claims that the coal pricing assumptions in the 2023 Fuel Plan lack support, do not match those in the 2024 TAM, and change significantly between scenarios.[34] These claims are wrong. The pricing differentials appropriately reflect changes in assumptions among the scenarios. Most notably, scenarios that assume an earlier closure date for the Bridger mine necessarily include accelerated depreciation and reclamation costs. Sierra Club simply ignores the fact that an earlier closing date for the Bridger mine requires the accelerated collection of prudently incurred net investment and reclamation costs and associated coal price increases.

[33] Sierra Club/100, Burgess and Roumpani/21.
[34] Sierra Club/100, Burgess and Roumpani/23.

Q. Sierra Club also complains that 2023 costs were included in the PVRR calculation, even though 2023 is irrelevant for planning purposes and significantly inflates the benefits of the Preferred Scenario.[35] Why did the Company use 2023 as the first year of the 2023 Fuel Plan?

A. The Company commonly starts its planning horizon with the year in which the plan is filed. For example, the 20-year planning horizon for the 2023 IRP begins in 2023. Since the long-term fuel plan is now synced in timing with the IRP, it makes sense to use the same 2023 start date for the planning horizon for each 2023 plan.

Q. Sierra Club objects to the derivation of the Preferred Scenario by comparing the PVRR of each scenario using major net power cost components. Sierra Club asserts that this results in selection of the Preferred Scenario based on the Company's ability to sell power.[36] Please respond.

A. PacifiCorp has identified an error in the reporting of market purchases and sales in the 2023 Fuel Plan results, which made wholesale sales appear to be a larger portion of the benefits in Scenario 5 than was actually the case. This does not change the overall conclusion that Scenario 5 is the most cost-effective alternative available. Based on the corrected reporting of results, over the 2023-2029 study horizon, approximately 11 percent of the incremental Jim Bridger coal-fired generation in Scenario 5 relative to Scenario 4 took the form of additional market sales, including 21 percent in 2024. The majority of the incremental Jim Bridger coal-fired generation displaced higher-cost coal and gas-fired generation, as well as market purchases. In addition, even if market prices or other system conditions resulted in

[35] Sierra Club/100, Burgess and Roumpani/22–23.
[36] Sierra Club/100, Burgess and Roumpani/23.

lower demand for coal supply at Jim Bridger plant, Scenario 5 is utilizing nearly all possible deliveries from SPRB, which have a higher cost than incremental volumes from BCC. SPRB volumes are procured using short-term contracts and can readily be reduced in response to changing conditions. If a future reduction in Jim Bridger plant coal demand exceeds the projected SPRB volumes, PacifiCorp can also transition from Scenario 5 to operations consistent with Scenario 4 or Scenario 3 and will continue to evaluate its BCC operations in future long-term fuel plans and as part of Jim Bridger coal supply procurement.

Q. Do you have any general comments about the inclusion of wholesale sales in the 2023 Fuel Plan?

A. First, the Company's ability to sell power is directly related to investments in mining, generation, and transmission facilities that enable the Company to participate in wholesale power sales. This unique ability is a key component of the Company's strategy to reliably provide customers with electricity at reasonably priced rates. This ability means customers are less impacted by adverse and unexpected changes in the volatile power, natural gas, and coal markets. Second, wholesale power sales are a major component of NPC and are duly recognized as such by the Company and Commission. Sierra Club improperly cherry picks NPC components to support their flawed narrative. Lastly, while the present value of the wholesale power sales is a contributing factor to lower NPC in Scenarios 5 and 6, removing wholesale power sales from the PVRR calculation would not result in Scenario 4 being the Preferred Scenario. Sierra Club's assertion is without merit and flawed.

Q. Sierra Club challenges the 2023 Fuel Plan because the Company [redacted].[37] Sierra Club also recommends that PacifiCorp include this scenario in future fuel plans.[38] Did the Company include a similar scenario?

A. Yes. In Scenario 3, [redacted]. This scenario was much less cost-effective than the Preferred Scenario.

Q. Sierra Club recommends that the Company provide an updated Jim Bridger long-term fuel plan annually in each TAM.[39] Is this a reasonable recommendation?

A. No. The Commission has directed the Company to file the long-term fuel plan in conjunction with the IRP. As noted above, this makes sense because (1) the IRP relies upon data developed for the long-term fuel plan, and (2) the long-term fuel plan relies upon the resource mix in the preferred portfolio from the biennial IRP filing. Sierra Club's proposal for annual long-term fuel plans in the TAM would disconnect the IRP and the long-term fuel plan, which is both problematic and unnecessary.

[37] Sierra Club/100, Burgess and Roumpani/31.
[38] Sierra Club/100, Burgess and Roumpani/33.
[39] Sierra Club/100, Burgess and Roumpani/33.

Q. Sierra Club makes several other recommendations for future fuel plans. First, Sierra Club recommends that the Company use PLEXOS or Aurora, clearly identify all assumptions and inputs, and provide supporting workpapers.[40] Is the Company already following this recommendation?

A. Yes, the Company is already using PLEXOS in the 2023 Fuel Plan. The Company provides in discovery all assumptions, inputs, and workpapers for its long-term fuel plans as requested.

Q. Next, Sierra Club recommends that future fuel plans should allow Jim Bridger generation to be replaced by new resources.[41] Please comment.

A. The 2023 Fuel Plan was developed using a preliminary version of the 2023 IRP preferred portfolio, which includes new resources. Changes incorporated in later versions of the 2023 IRP preferred portfolio were primarily beyond the last year of the 2023 Fuel Plan in 2029 (the IRP has a 20-year planning horizon). The preferred portfolio includes over eight gigawatts of wind and solar resources and over seven gigawatts of storage resources added during the 2023 Fuel Plan horizon. While resource portfolio changes could impact the outcome of future long-term fuel plans, the results and conclusion of the 2023 Fuel Plan identifying Scenario 5 as the preferred scenario provide flexibility to accommodate such changes. Unlike some of the other scenarios considered, Scenario 5 does not require a long-term commitment, and allows for cost savings from a transition to lower production levels, such as those in Scenario 4, should such a transition become economic at a future date.

[40] Sierra Club/100, Burgess and Roumpani/33.
[41] Sierra Club/100, Burgess and Roumpani/28, 33.

Q. Sierra Club recommends that future fuel plans continue to include a scenario without minimum take or minimum burn requirements and using average prices for plant dispatch.[42] Please comment.

A. The Company will continue to review a range of scenarios in future long-term fuel plans. The scenario without a minimum take (Scenario 6), for which Sierra Club advocates here, has the same result as the Preferred Scenario (Scenario 5) and did not contribute meaningfully to the analysis in the 2023 Fuel Plan.

Q. Does this conclude your reply testimony?

A. Yes.

[42] Sierra Club/100, Burgess and Roumpani/33.

REDACTED
Docket No. UE 420
Exhibit PAC/501
Witness: James Owen

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Exhibit Accompanying Reply Testimony of James Owen

Hunter/Wolverine Coal Supply Agreement Analysis

July 2023

THIS EXHIBIT IS HIGHLY CONFIDENTIAL IN ITS ENTIRETY AND IS PROVIDED UNDER SEPARATE COVER

REDACTED
Docket No. UE 420
Exhibit PAC/502
Witness: James Owen

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Exhibit Accompanying Reply Testimony of James Owen

Jim Bridger Plant Long-Term Fueling Plan

July 2023

PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah Street, Suite 2000
Portland, Oregon 97232

May 31, 2023

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street SE, Suite 100
Salem, OR 97301-3398

Re: LC 82—PacifiCorp's Jim Bridger Long-Term Fuel Plan

In accordance with Order No. 23-131 issued in docket LC 82 on April 6, 2023, PacifiCorp d/b/a Pacific Power hereby submits for filing its Jim Bridger Long-Term Fuel Plan (LTFP).

The Jim Bridger LFTP contains highly commercially sensitive, non-public information related to PacifiCorp's fueling strategy at the facility. As a result, PacifiCorp classifies the Jim Bridger LTFP as containing both confidential and highly confidential information and provides it in accordance with the General Protective Order No. 16-128 and Modified Protective Order 23-120 in Docket No. UE 420, and General Protective Order 23-132 for Docket No. LC 82. A Revised Motion for Modified Protective Order in Docket LC 82 was filed on May 26, 2023, and an order is pending.

Please direct any inquiries about this filing to Cathie Allen, Regulatory Affairs Manager, at (503) 813-5934.

Sincerely,

Matthew McVee
Vice President, Regulatory Policy and Operations

Enclosure

cc: UE 420

PACIFICORP HIGHLY CONFIDENTIAL LONG-TERM FUEL SUPPLY PLAN FOR THE JIM BRIDGER PLANT

May 31, 2023

PACIFICORP
A BERKSHIRE HATHAWAY ENERGY COMPANY

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1 INTRODUCTION AND EXECUTIVE SUMMARY

In PacifiCorp's 2014 Transition Adjustment Mechanism (TAM) filing, the Public Utility Commission of Oregon (Oregon Commission) adopted PacifiCorp's proposal to prepare periodic fuel supply plans comparing affiliate mine supply to alternative fuel supply options, including market alternatives for the Jim Bridger Power Plant.[1] As set forth in PacifiCorp's compliance filing in the 2015 TAM, Docket UE 287, the purpose of long-term fuel supply plans for plants fueled from captive mines is to determine the least-cost, risk-adjusted coal supply evaluated on a multi-year basis. The long-term fuel plan is designed to ensure that fuel supplies are fair, just, and reasonable, and that they satisfy the Oregon Commission's prudence and affiliate interest standards.

PacifiCorp has previously filed long-term fuel plans in December 2015, March 2018, and April 2022. After the Company filed the 2018 Fuel Plan, the Oregon Commission directed PacifiCorp to develop an alternative analysis using a shortened plant life of January 1, 2030, instead of December 31, 2037, to comply with Oregon Senate Bill (SB) 1547 signed in 2016. PacifiCorp refreshed the 2018 Fuel Plan in March 2019 to evaluate the reasonableness of the Company's fueling strategy for the Jim Bridger plant using the shortened plant life. The 2023 Fuel Plan is consistent with Oregon SB 1547 as it contemplates consuming coal through 2029, in conformity with PacifiCorp's 2023 Integrated Resource Plan (IRP).

In the October 2021 final order in PacifiCorp's 2022 TAM, the Oregon Commission required PacifiCorp to provide an updated long-term fuel plan in 2022 and submit it with the 2023 TAM. In February of 2022, PacifiCorp sought to delay this filing because several events had created significant uncertainty which prevented the Company from definitively determining the least-cost, risk-adjusted coal supply for the Jim Bridger plant at that time.[2] Specifically, those events included actions by the United States Environmental Protection Agency (EPA) around Jim Bridger's regional haze obligations, revised dates for Idaho Power Company's exit from the Jim Bridger plant, and PacifiCorp's commitment to evaluate carbon capture, utilization and sequestration (CCUS) at the Jim Bridger plant.

Recognizing the uncertainties and difficulties, the Oregon Commission required PacifiCorp to file the 2022 Fuel Plan in April 2022 and clarified that the plan did not need to be a final strategy. While the 2022 Fuel Plan was preliminary, it considered the options available to PacifiCorp based on the best information available at the time. The 2023 Fuel Plan has confirmed the findings of the 2022 Fuel Plan and is likewise based on the best available information. Some uncertainties have been resolved in the last year, however uncertainty still exists surrounding many issues including the EPA's establishment of new nitrogen oxides (NOx) emissions budgets under Ozone National Ambient Air Quality Standards (Ozone Transport Rule) in the state of Wyoming, CCUS requirements, and coordination with Idaho Power Company on exit or gas conversion dates.

In the May 2022 final order in PacifiCorp's 2021 IRP Filing, the Oregon Commission directed PacifiCorp "to file an updated long-term fuel plan for Jim Bridger with its 2023 IRP… PacifiCorp agreed with that

[1] *In the Matter of PacifiCorp d/b/a Pacific Power, 2014 Transition Adjustment Mechanism*, Docket No. UE 264, Net Power Costs Approved Subject to Adjustments, Order No. 13-387 (Oct. 28, 2013).
[2] *In the Matter of PacifiCorp d/b/a Pacific Power, 2022 Transition Adjustment Mechanism*, Docket No. UE 390, Motion to Amend Order No. 21-379 (Feb. 11, 2019).

assessment and consented to provide the updated plan with the 2023 IRP"[3] which was released on March 31, 2023. In April 2023, the Oregon Commission extended the deadline to May 31, 2023.[4]

In the October 2022 final order of PacifiCorp's 2023 TAM, the Oregon Commission approved a stipulation where PacifiCorp agreed that "[m]odeling for the Long-Term Fuel Supply Plan will be conducted in a platform able to accept multiple fuel price tiers such as Aurora or PLEXOS. PacifiCorp will include the following scenarios:

i. Scenario that does not assume a minimum take at either the Black Butte or Bridger Mine; *(Refer to Scenario 6 below)*
ii. Scenario evaluating an alternative to the minimum take requirement in the Black Butte coal supply agreement signed in 2022; *(Refer to Scenario 1 below)*
iii. Scenario evaluating early closure of the Bridger mine (before 2028) and fueling Jim Bridger through end of life with stockpiled coal supplies. *(Refer to Scenario 3 below)*"[5]

To develop the 2023 Fuel Plan, PacifiCorp studied, reviewed, and evaluated different fueling options for the Jim Bridger plant. The evaluation of these fueling options provides valuable insight into [redacted] As part of its 2023 IRP, PacifiCorp assessed various long-term coal supply options as well as alternative options for Jim Bridger Units 3 and 4, including retrofit for CCUS, conversion to natural gas and/or other alternative fuels, and early retirement. The 2023 IRP preferred portfolio selected the conversion of Units 3 and 4 to natural gas in 2030 which requires the ending of coal consumption by December 31, 2029.

Within the 2023 Fuel Plan, the Company has presented several different fueling options. The fueling options consider varying delivery schedules sourced from Bridger Coal Company (Bridger mine), the Black Butte mine, and mines located in Wyoming's Southern Powder River Basin (SPRB). Additionally, the different coal delivery options for the Bridger mine contain various mine plan scenarios outlining specified delivery schedules. Included in these different mine scenarios are estimated shutdown dates for the Bridger mine.

The 2023 Fuel Plan provides third-party coal supply volume and pricing estimates based upon the current contract and ongoing discussions with the Black Butte mine, as well as recent coal pricing forecasts from Energy Ventures Analysis (EVA). The 2023 Fuel Plan provides estimated volumes and rail rates for transportation services based on agreements with the Union Pacific Railroad (UPR) for the transport of coal from third-party coal supply sources. The estimated plant modifications and capital requirements, defined by equipment category, as well as total costs needed to support large volumes of SPRB coal are derived from a detailed third-party study completed in 2017 by the engineering and consulting firm Burns & McDonnell, adjusted for inflation and to account for volumes associated with operating two coal units instead of four coal units.

After considering factors influencing the long-term fueling strategy and information available to PacifiCorp at this time, the Company developed and evaluated six Jim Bridger plant coal fueling options:

[3] *In the Matter of PacifiCorp d/b/a Pacific Power, 2021 Integrated Resource Plan*, Docket No. LC 77, 2021 IRP Acknowledged with Modifications and Exceptions, Order No. 22-178 (May 23, 2022).
[4] *In the Matter of PacifiCorp d/b/a Pacific Power, 2023 Integrated Resource Plan*, Docket No. LC 82, Order No. 23-131 (Apr. 6, 2023).
[5] *In the Matter of PacifiCorp d/b/a Pacific Power, 2023 Transition Adjustment Mechanism*, Docket No. UE 400, Comprehensive Stipulation Adopted: Directives for Future Filings, Order No. 22-389 (Oct. 25, 2022).

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- **Scenario 1** [redacted]
- **Scenario 2** [redacted]
- **Scenario 3** [redacted]
- **Scenario 4** [redacted]
- **Scenario 5** [redacted]
- **Scenario 6** [redacted]

As a preliminary indication of the cost-effectiveness of the proposed scenarios using recent assumptions, the Company completed a Present Value Revenue Requirement (PVRR) calculation, comparing major components of PacifiCorp's system costs resulting from the various fueling options, including a composite ranking considering both financial and risk weighting. These costs include coal purchases, natural gas purchases, and system power purchases offset by wholesale power sales (System Costs). Other components not considered in the analysis include costs associated with qualifying facilities, power purchase agreements, geothermal and wheeling. These items do not vary with system dispatch in the PLEXOS model and would not vary between scenarios. This analysis is based on the Company's forward price curve for power and natural gas, which does not include greenhouse gas costs, but does account for the impacts of certain recently proposed EPA emissions requirements, such as the Ozone Transport Rule. The results of the PVRR analysis and risk evaluation indicate that Scenario 5 and Scenario 6 are the current least-cost, risk-adjusted options. Option 6 was modeled assuming no minimum take-or-pay obligations for the Bridger mine or Black Butte Coal Company. Based on PacifiCorp's evaluation using the PLEXOS model, all of the available incremental coal from the Bridger mine would be cost-effective. As a result, the fueling plans in Scenario 5 and Scenario 6 are essentially the same. Therefore, Scenarios 5 and 6 will be referred to as the "Preferred Scenario" in this report going forward.

The benefits of pursuing the Preferred Scenario as the long-term fueling strategy for the Jim Bridger plant include the following:

- Provides the least-cost, risk-adjusted fuel supply for the Jim Bridger plant,
- [redacted]
- [redacted]
- [redacted]

Although the Preferred Scenario is the current least-cost, risk-adjusted fueling option for the Jim Bridger plant, PacifiCorp will continue to evaluate the best fueling option for the Jim Bridger plant, taking into consideration both cost and risk, and will update the long-term fuel supply plan after each IRP is released to reflect changing assumptions and expectations.

2 EVALUATION METHODOLOGY

In the 2023 Fuel Plan, PacifiCorp evaluated several different fueling options for the Jim Bridger plant. The methodology used to evaluate the fueling options is similar to the methodology used in the April 2022 long-term fuel plan. As noted above, the 2023 Fuel Plan considers the variable components of PacifiCorp's System Costs. The same production software used in the 2023 Integrated Resource Plan (IRP), PLEXOS, was used for the 2023 Fuel Plan. Prior plans used PacifiCorp's Generation and Regulation Initiative Decision Tools model (GRID) and costs for the consumed tons required to support the generation forecast under each fueling option were then calculated. The cost of coal for the Jim Bridger plant under each fueling option was then compared to the system benefits of incremental coal-fired generation from the PLEXOS model on a PVRR basis.

3 BACKGROUND

The Jim Bridger plant is a coal-fired plant located in Sweetwater County, Wyoming. The facility is located approximately eight miles north of Point of Rocks, Wyoming, and approximately 24 miles east of Rock Springs, Wyoming.

The Jim Bridger plant is the largest power plant on the PacifiCorp system (2,120 megawatts) and is jointly owned by PacifiCorp (66.7%) and Idaho Power Company (Idaho Power) (33.3%). The Jim Bridger plant consists of four almost identical units, each with a nominal 530 net megawatt capacity. Over the four-year period of 2019-2022, the Jim Bridger plant consumed approximately 24 million tons of coal, an average of six million tons per year. The plant is designed to consume coal sourced from southwest Wyoming with heat content in the range of 9,000 Btu/lb. to 10,000 Btu/lb.

The Bridger mine is located adjacent to the Jim Bridger plant. Having ceased underground mining operations in December 2021, the Bridger mine currently consists solely of surface mining operations. Like the Jim Bridger plant, the Bridger mine is jointly owned by PacifiCorp (66.7%) and Idaho Power (33.3%). The surface mine is a combination dragline and truck/loader operation that produces approximately [redacted] million tons of coal per year.

For regulatory purposes, the Bridger mine is consolidated with PacifiCorp's operations. PacifiCorp's share of the Bridger mine is included in the PacifiCorp rate base and its share of mining costs, including depreciation and depletion, is included in System Costs.

In addition to the Bridger mine deliveries, the Jim Bridger plant has historically received the remaining portion of its coal supply requirements from the nearby Black Butte mine. The UPR provides rail access for all the coal delivered from the Black Butte mine to the plant.

4 ASSUMPTIONS

Currently, the Jim Bridger plant has three potential sources for coal supply:

- The Bridger mine
- The Black Butte mine

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- Wyoming's SPRB mines

As demand for generation from the Jim Bridger plant is expected to decline significantly after Units 1 and 2 convert to natural gas in 2024, the 2023 Fuel Plan examines scenarios ranging from [redacted]

To assist with the characterization of the potential supply changes over time, the fueling options have been separated into "near-term" and "long-term" periods for discussion purposes. For purposes of the 2023 Fuel Plan, the near-term period has been defined as 2023 and corresponds to the time that Units 1 and 2 are consuming coal before the conversion of those units to gas operation. The key assumptions in the 2023 Fuel Plan are explained below:

4.1.1 Generation

As mentioned above, generation forecast assumptions are provided by PacifiCorp's PLEXOS model for each fueling option studied. To ensure compliance with the Regional Haze Consent Decree with the State of Wyoming, the 2023 Fuel Plan assumes Jim Bridger Units 1 and 2 will stop consuming coal December 31, 2023, and convert to natural gas in 2024. Consistent with the outcome of the 2023 IRP, Jim Bridger Units 3 and 4 will continue to consume coal until December 31, 2029, and then also convert to natural gas in 2030.

On a total plant basis (i.e., including Idaho Power's expected consumption), coal consumption is forecast to be in the range of [redacted] million to [redacted] million tons for 2023.

4.1.2 Plant Depreciable Life

The assumed depreciable life in Oregon of PacifiCorp's share of the Jim Bridger plant extends through 2029 for Units 1 and 2 and through 2025 for Units 3 and 4. Other states in PacifiCorp's service territory use differing depreciable lives for different units ranging from 2023 to 2037, based upon PacifiCorp's 2018 depreciation study and other regulatory agreements.

4.1.3 Bridger Mine Plans

In early 2023, the Bridger mine prepared three operating mine plans; [redacted]

[redacted]

[redacted]

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[redacted]

[redacted]

[redacted]

4.1.4 Third Party Coal

Due to the geographic location of the Jim Bridger plant, economic fuel supply alternatives other than the Bridger mine are limited to one additional operating mine located in southwest Wyoming and the SPRB mines of Campbell County, Wyoming.

The Black Butte mine, located 20 miles southeast of the Jim Bridger plant, is operated by Lighthouse Resources Inc. (Lighthouse). Lighthouse emerged from bankruptcy in 2020. The mine is a multiple seam, multiple pit operation with the overburden removed by draglines and a truck/loader fleet. In recent years, the mine has produced less than [redacted] tons per year and the Jim Bridger plant has been the mine's primary customer. Between 2019 and 2022 the Jim Bridger plant received approximately [redacted] tons, an average of [redacted] tons per year, from the Black Butte mine. Coal from the Black Butte mine is delivered by rail to the Jim Bridger plant under an agreement with UPR.[6]

The Powder River Basin is the largest coal mining region in the United States. Coal from the SPRB is classified as sub-bituminous coal. SPRB coal contains an average heat content of approximately 8,800 Btu/lb. The coal mined in the SPRB is low sulfur and low ash. Due to its unique quality characteristics, SPRB coal has been consumed by energy markets in multiple states across the country. In 2022, there were seven mining companies operating twelve active mines in Wyoming's Powder River Basin, producing roughly 238 million tons. SPRB mines contain the highest heat content coal in the basin ranging between 8,600 Btu/lb. and 8,950 Btu/lb. These mines are located about 550 miles from the Jim Bridger plant. SPRB mines and the Jim Bridger plant are served by UPR. Consumption of SPRB coal requires UPR delivery.

4.1.5 Black Butte Pricing

As of May 2023, coal from the Black Butte mine is purchased under a Coal Supply Agreement (CSA) signed June 19, 2022, that ends December 31, 2023. [redacted]

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[6] Due to limited coal reserves, estimated production costs, transportation difficulties, and the planned closure of the Naughton plant in 2025, Kemmerer Operations, LLC's Kemmerer mine is not considered a viable fuel source for the Bridger plant.

[redacted]

4.1.6 Black Butte Mine Volume

PacifiCorp conducted a high-level review of the Black Butte mine coal resource and reserve estimates in 2015. The study consisted of reviewing available third-party Black Butte reserve and geology documents, along with Black Butte's geology information and permitting status. At the time, based on the information reviewed, the conclusion of the review was that the Black Butte mine had [redacted] tons that could be considered economic coal reserves under the terms and conditions of the then-current contract.

PacifiCorp and Idaho Power purchased 14 million tons between 2016 and 2022. The scenario that consumes the highest volume of Black Butte coal, assumes purchases of [redacted] tons by PacifiCorp and Idaho Power between 2023 and 2029. Therefore, this study assumes that Black Butte has sufficient coal reserves to satisfy the Jim Bridger plant. Note that the reserve estimate includes the expansion of Black Butte mine into the Pit 15 area. As of May 2023, the permitting process for this area is still pending with federal government agencies. If Pit 15 is not permitted, the risk exists that sufficient reserves may not be available from the Black Butte mine under [redacted]

4.1.7 Assumed SPRB Coal Pricing

Coal pricing for 2023 comes from a coal supply agreement with [redacted]. Volumes purchased by PacifiCorp range from [redacted]. SPRB coal pricing in the 2023 Fuel Plan beyond 2023 is based on a long-term coal forecast published by EVA in spring 2023.

4.1.8 Powder River Basin Coal in the Near-Term

Powder River Basin coal has a high propensity to spontaneously combust and is the most friable coal type consumed in the power industry. While major plant modifications would be required to receive and consume large volumes of SPRB coal safely and reliably at the Jim Bridger plant, currently the plant is likely capable of consuming SPRB coal on a limited scale without major modification to the plant's coal unloading or coal consuming infrastructure. For example, in a test during 2015, the plant handled and consumed 10 trains totaling 140,540 tons of SPRB coal. Based on knowledge gained from that test and PacifiCorp's professional judgment, PacifiCorp believes that up to a total of 800,000 tons of SPRB coal per year can be safely and reliably consumed without major modifications to the plant infrastructure. This estimate is considered aggressive, as issues with scheduling or handling coal could result in lower maximum annual SPRB volumes using the existing infrastructure. The current 800,000-ton assumption could be adjusted based upon the results of actual coal deliveries in 2023 from the [redacted]

4.1.9 Transportation

Coal from the Bridger mine is delivered to the Jim Bridger plant via conveyor belt, and the cost of conveying the coal is included in the delivered coal cost. The Jim Bridger plant is also connected by a rail spur to the UPR mainline track. UPR has the trackage rights to the mainline and spur to the Jim Bridger plant and, as a result, the Jim Bridger plant is captive to UPR for deliveries by rail. Deliveries from all sources other than the Bridger mine are assumed to be delivered by the UPR. As mentioned above, the transportation rates for delivery of Black Butte and SPRB coal are based upon the current rail transportation agreement with UPR and escalated beyond 2023.

4.2 Jim Bridger Plant Capital

PacifiCorp selected the consulting firm Burns & McDonnell (B&M) to perform an independent capital evaluation of the plant modifications and capital expenditures required at the Jim Bridger plant to consume volumes, up to 100%, of SPRB coal. B&M completed a comprehensive study in June 2017. The study outlined high priority plant modifications and the estimated costs in converting the Jim Bridger plant's main fuel source to SPRB coal. The study focused on required modifications to several systems including coal handling and storage, rail delivery, mechanical process/power island, electrical, substation and overhead distribution and air permitting.

The required coal handling system modifications identified engineering controls that would be needed and relied upon to reduce and mitigate coal dust throughout the coal handling system. The study emphasized the importance of having adequate wash down capability by installing and utilizing fixed pipe wash down systems in existing coal reclaim and conveyor tunnels, crusher houses, tripper bays and in the rail unloading hopper facilities. The study also assumed a loop track and thaw shed would be required. Recommendations were made on how to safely and reliably handle SPRB coal: keep areas clean, eliminate ignition sources and detect spontaneous combustion with accumulated SPRB coal dust. These safety steps are designed to protect people, equipment, and enclosures from explosions due to the dangerous spontaneous combustion tendencies of SPRB coal.

Required modifications to the rail delivery system outlined in the 2017 study indicate that the current unloading configuration is [redacted]

In the 2023 Fuel Plan, the capital modifications for [redacted] The 2023 Fuel Plan assumes that Idaho Power will participate in the capital modifications. PacifiCorp's estimated cost of the capital modifications based on B&M's June 2017 study is approximately [redacted], as provided in Table 1.

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TABLE 1
Jim Bridger Plant Capital Costs

[redacted]

5 FUEL SUPPLY MIX

PacifiCorp evaluated six fueling scenarios for the Jim Bridger plant for the 2023 Fuel Plan. Those scenarios are described below. Please refer to Appendices 1-13 for detailed fueling mix and pricing information for each fueling option considered. Summaries of the fuel supply mix, including average volumes for the near-term and long-term, for each fueling option evaluated are provided below. Note that Scenarios 5 and 6 result in the same solution but were run in PLEXOS with different assumptions as seen below.

5.1 SCENARIO 1 [redacted]

Scenario 1 considers [redacted]

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5.2 Scenario 2 [redacted]

Scenario 2 considers [redacted]

5.3 Scenario 3 [redacted]

Scenario 3 considers [redacted]

5.4 Scenario 4 [redacted]

Scenario 4 considers [redacted]

5.5 Scenario 5 [redacted]

Scenario 5 considers [redacted]

5.6 Scenario 6 [redacted]

Scenario 6 considers [redacted]

6 PVRR ANALYSIS AND RESULTS

6.1 Jim Bridger Coal Fueling Cost Analysis

The PVRR analysis represents a present value revenue requirement using major NPC components for the PacifiCorp system. The fuel costs for all coal and gas plants are included along with power purchase costs offset by power sales revenues. Scenario 2 [redacted] The PVRR results have been discounted using PacifiCorp's weighted average cost of capital. A total PVRR

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differential has been calculated for each of the six fueling scenarios comparing the total PVRR for each option against the Preferred Scenario, the fueling option with the lowest PVRR dollar amount.

Table 2 below shows the results of the PVRR analysis for each fueling option in the 2023 Fuel Plan supplying the Jim Bridger plant with coal through December 2029. Also included in Table 2 is a financial ranking from 1 to 6 for each of the fueling options. Table 2 also shows the Preferred [redacted] The other fueling options range between these options. Additional discussion on risk assessment for each fueling option is presented in the next section below.

TABLE 2
PVRR Analysis Through December 2029

[redacted]

6.2 Risk Analysis

The following table provides a risk assessment for each scenario and outline the specific categories that have been considered in the risk evaluation analysis. Table 3 illustrates a risk assessment of Scenarios 1 through 6 through December 2029.

TABLE 3
Risk Evaluation Through 2029

[redacted]

The defined risk profile categories include (1) Incremental Capital – the risks associated with the total costs of incremental capital expenditures related to each fueling scenario, (2) Coal Market – risks associated with adequate coal supplies, as well as coal and transportation price, (3) Power and Natural Gas Market Volatility – risks associated with power market price volatility driven by changing natural gas prices, availability of hydro generation, impacts of renewable energy sources, load demand, and (4) Jim Bridger Plant Environmental Compliance – risks associated with new environmental regulations that could change generation at the Jim Bridger plant.

For each fueling scenario under each risk category, a number ranging between 1 and 4 has been assigned. Number 1 is designated as "favorable and low risk." Number 2 is "favorable and moderate risk," and number 3 is "less favorable and high risk." Number 4 is designated as "least favorable and highest risk." The sum of the risk numbers for each category for each scenario, results in an overall "composite project risk" score.

[redacted]

[redacted]

[redacted]

[redacted]

7 REMAINING UNCERTAINTIES

Recent and ongoing events have increased uncertainty around the future of Jim Bridger plant's fuel plans in a way that make definitive Jim Bridger long-term coal supply decisions or commitments high risk at this time. The following is a short summary of some of the major uncertainties that impact the 2023 Fuel Plan and an explanation of how the plan may change depending on the resolution of the uncertainties.

7.1 Jim Bridger Gas Conversions

Jim Bridger Units 1 and 2 are scheduled to be converted to natural gas in 2024 as required by a Regional Haze Consent Decree with the State of Wyoming. Based on the Company's 2023 IRP, Units 3 and 4 are scheduled to be converted to natural gas in 2030. The 2023 IRP analyzed a scenario where Jim Bridger Units 3 and 4 were not converted to natural gas, which resulted in significantly higher costs to PacifiCorp customers.[7] The natural gas conversion of Jim Bridger Units 1 and 2 is an enforceable environmental compliance requirement (Regional Haze requirements under the Clean Air Act (CAA)) under a consent decree entered into by the state of Wyoming and the Company[8] and an administrative consent order with EPA. The state of Wyoming issued an air permit for the natural gas conversion of Jim Bridger Units 1 and 2 in December 2022, as well as submitted a state-approved revised regional haze state implementation plan to EPA requiring the natural gas conversion. EPA is reviewing the submission and is expected to conduct a separate federal public comment process on the plan in summer of 2023. PacifiCorp submitted a notice of compliance and request for termination of the EPA order in March of 2023, which is currently under EPA review. While some of these processes have not yet been finalized, and uncertainty remains, the gas conversion process is underway and any alternative compliance scenarios will be based on Units 1 and 2 converting to gas. The conversion of Units 3 and 4 is further out in time and thus subject to more uncertainty. Due to these uncertainties, [redacted]

7.2 PacifiCorp's commitment and requirement to evaluate CCUS at Jim Bridger

Pursuant to Wyoming Statute §§ 37-18-101 and -102 and the Wyoming Public Service Commission Administrative Rules, PacifiCorp is required to analyze the suitability of CCUS at coal fired electric generation facilities, owned in whole or in part with another utility or utilities subject to the provisions of Wyo. Stat. § 37-18-102(a). The Company has determined that Jim Bridger Units 3 and 4 are potentially suitable candidates for CCUS. Additionally, the consent decree entered into by the state of Wyoming and the Company required the Company to issue request(s) for proposals (RFP) for the installation of CCUS at Jim Bridger Units 3 and 4 no later than January 1, 2023. PacifiCorp released the CCUS RFP to qualified bidders in November of 2022 for the Jim Bridger facility. [redacted]

CCUS installation at Jim Bridger Units 3 and/or 4 has the potential to significantly impact coal burn and dispatch. The generation forecast and coal requirement at the Jim Bridger plant will likely increase if PacifiCorp elects to, or is required to, install CCUS at Bridger Units 3 and/or 4. Proceeding with the Preferred Scenario in the near-term would not preclude the future installation of CCUS at the Jim Bridger plant while PacifiCorp continues to evaluate options and work to comply with Wyoming's CCUS regulations. Fueling strategies for CCUS scenarios would focus on availability and reliability of coal supply.

[7] PacifiCorp's 2023 IRP, Chapter 9 – Modeling and Portfolio Selection Results, pages 266-267.
[8] Wyoming Consent Decree, Docket No. 2022-CV-200-333 (February 14, 2022).

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7.3 PROPOSED EPA RULES

Ozone Transport Rule

The EPA proposed a federal implementation plan for 26 states, including Wyoming, in April of 2022, to eliminate significant contributions to nonattainment of the 2015 ozone National Ambient Air Quality Standard (NAAQS) in neighboring states, known as the Ozone Transport Rule, "good neighbor rule," or "interstate transport" provision of the CAA.[9] However, on January 31, 2023, EPA delayed final action on Wyoming's ozone interstate transport state implementation plan to December of 2023. Wyoming cannot be included in the federal plan until EPA disapproves the state plan. EPA finalized its federal ozone plan on March 15, 2023, but deferred action on Wyoming, meaning the state is currently not subject to the federal plan but could be once EPA finalizes its determination on the state plan. EPA's deferral of Wyoming is currently under litigation. EPA's federal plan is focused on reducing NOx, a precursor to ozone formation, and requires fossil-fuel-fired power plants to participate in an allowance-based ozone season trading program beginning in 2023. The federal rule includes SCR-like NOx budgets for each generating unit and will impact the Company and its operations. The final rule has been released by EPA but has not yet been published in the Federal Register, meaning compliance timelines are not yet established.

Jim Bridger Units 3 and 4 are currently equipped with SCR. Given the impacts of the federal plan on PacifiCorp's Utah coal plants, and depending on EPA's determination on Wyoming's state plan, these units may take on a more critical role in the compliance and reliability strategy for PacifiCorp's fleet and may operate at higher levels than previously forecasted during the ozone season (May – September). Proceeding with the Preferred Scenario, as explained above when discussing the possibility of CCUS at the Jim Bridger plant, keeps all the fueling alternatives on the table as PacifiCorp determines the most effective course of action for compliance with the rule and preserving reliability. Litigation of Utah and other state plan disapprovals is currently underway, and the final rule is also expected to be heavily litigated.

EPA's deferred action on Wyoming's state plan creates a great deal of uncertainty about how the Ozone Transport Rule will impact PacifiCorp's coal fleet. While this is pending, the Preferred Scenario is the most economical in the interim and will provide PacifiCorp time to better understand this potential regulation and its impacts on the generation fleet.

Greenhouse Gas Rule

EPA issued proposed regulations under section 111 of the CAA on May 23, 2023, to address greenhouse gas emissions from fossil-fuel fired electric generating units (the "Greenhouse Gas Rule"). The standards proposed in the rule would regulate new gas-fired combustion turbines and set standards for states to regulate existing coal plants, converted natural gas plants and certain large and frequently used existing gas turbine plants. The standards vary significantly based on facility-specific factors – including whether the unit is new or existing, whether it is fueled by coal or natural gas, how frequently it operates, and whether it is scheduled to retire in the coming years. Coal units operating beyond 2032 face increasingly stringent emission limits, and those operating beyond 2040 must comply with emission limits consistent with carbon capture and sequestration starting in 2030. PacifiCorp is evaluating the specific impacts of the proposal and how they impact the Bridger Units and the fueling plan. The impacts from the Greenhouse Gas Rule create some uncertainty due to changing future requirements for coal and gas units and because these requirements could be adjusted when the rule is finalized. The Preferred Scenario allows PacifiCorp

[9] *See* 42 U.S.C. 7410(a)(2)(D)(i)(I); 87 Fed. Reg. 20036 (April 6, 2022).

to maintain options to address the impacts and system-wide adjustments that may result from the proposed rule.

7.4 IDAHO POWER COMPANY'S PLANNED EXIT DATES

PacifiCorp's 2023 IRP Preferred Portfolio plans for Jim Bridger plant Units 1 and 2 to cease consuming coal on December 31, 2023, and convert to natural gas consumption. PacifiCorp's IRP also anticipates that Units 3 and 4 will cease consuming coal on December 31, 2029, and convert to natural gas. The IRP also provides December 31, 2037, as the closure date for all units. PacifiCorp and Idaho Power Company (Idaho Power) are aligned in the decision to consume coal in Units 1 and 2 through 2023, since Idaho Power's 2021 IRP calls for the conversion of two units to natural gas consumption in 2024. However, PacifiCorp and Idaho Power currently differ on the operation of Jim Bridger plant Units 3 and 4. Idaho Power's 2021 IRP provides December 31, 2025, as the closure date for a third Jim Bridger plant unit and December 31, 2028, as the closure date for a fourth Jim Bridger plant unit. Currently, these differences make modeling the Jim Bridger plant's future fueling needs difficult. Idaho Power is preparing an updated IRP which is scheduled to be released later in 2023. For purposes of the 2023 Fuel Plan, PacifiCorp has assumed the information in Idaho Power's 2021 IRP will remain the same. Ultimately, as co-owners of Jim Bridger plant and Bridger mine, PacifiCorp and Idaho Power will need to align their plans to best accommodate the unique needs of their respective customers. The solutions will impact each owner's access to and usage of the Jim Bridger plant and Bridger mine in the future.

8 CONCLUSION

In this 2023 Fuel Plan, PacifiCorp has identified a long-term fueling plan for the Jim Bridger plant that aligns with the Company's 2023 IRP, responds to changing fuel requirements, and allows flexibility to deal with uncertainty. This plan is PacifiCorp management's current strategy and lays out the various considerations and options available to PacifiCorp based on the best information available at this time. Alternative mine plans have been developed, evaluated, and reviewed for the Bridger mine which provided information and direction in determining the optimal volume at the Bridger mine.

After considering factors influencing this long-term fueling strategy and information available to the Company at this time, six different fueling options have been developed and evaluated. Based upon the results of the detailed PVRR analysis, which was further enhanced by utilizing a risk profile, the Preferred Scenario (Scenarios 5 and 6) provides the least-cost, risk-adjusted option and informs PacifiCorp's 2023 Jim Bridger plant fueling strategy. The Preferred Scenario assumes BCC operates two draglines. This plan would allow PacifiCorp [redacted]

[redacted]

[redacted]

Although the Preferred Scenario is the current least-cost, risk-adjusted fueling option for the Jim Bridger plant, energy market volatility and changing environmental legislation continues to create uncertainty around the future of Jim Bridger. PacifiCorp will continue to evaluate the best fueling options for the Jim Bridger plant as conditions change and as decision points for various supply options approach. PacifiCorp will update the long-term fuel supply plan after the 2025 IRP is finalized.

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APPENDIX 1 – SCENARIO 1 – [redacted]

[redacted]

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APPENDIX 2 – SCENARIO 2 – [redacted]

[redacted]

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APPENDIX 3 – SCENARIO 3 – [redacted]

[redacted]

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APPENDIX 4 – SCENARIO 4 – [redacted]

[redacted]

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APPENDIX 5 – SCENARIO 5 – [redacted]

[redacted]

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APPENDIX 6 – SCENARIO 6 – [redacted]

[redacted]

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APPENDIX 7 – JIM BRIDGER PLANT CONSUMED FUEL SUMMARY

[redacted]

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APPENDIX 7 – JIM BRIDGER PLANT CONSUMED FUEL SUMMARY (CONT'D.)

[redacted]

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APPENDIX 8 – SCENARIO 1 – JIM BRIDGER PLANT

[redacted]

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APPENDIX 8 – SCENARIO 1 – JIM BRIDGER PLANT (CONT'D.)

[redacted]

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APPENDIX 9 – SCENARIO 2 – JIM BRIDGER PLANT

[redacted]

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APPENDIX 9 – SCENARIO 2 – JIM BRIDGER PLANT (CONT'D.)

[redacted]

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APPENDIX 10 – SCENARIO 3 – JIM BRIDGER PLANT

[redacted]

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APPENDIX 10 – SCENARIO 3 – JIM BRIDGER PLANT (CONT'D)

[redacted]

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APPENDIX 11 – SCENARIO 4 – JIM BRIDGER PLANT

[redacted]

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APPENDIX 11 – SCENARIO 4 – JIM BRIDGER PLANT (CONT'D.)

[redacted]

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APPENDIX 12 – SCENARIO 5 – JIM BRIDGER PLANT

[redacted]

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APPENDIX 12 – SCENARIO 5 – JIM BRIDGER PLANT (CONT'D.)

[redacted]

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APPENDIX 13 – SCENARIO 6 – JIM BRIDGER PLANT

[redacted]

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APPENDIX 13 – SCENARIO 6 – JIM BRIDGER PLANT (CONT'D.)

[redacted]

CERTIFICATE OF SERVICE

I certify that I delivered a true and correct copy of PacifiCorp's **Jim Bridger Long Term Fuel Plan** on the parties listed below via electronic mail in compliance with OAR 860-001-0180.

Service List
LC 82

LANCE KAUFMAN 2623 NW BLUEBELL PL CORVALLIS OR 97330 lance@aegisinsights.com	AMY SCHLUSSER OREGON DEPARTMENT OF ENERGY amy.r.schlusser@energy.oregon.gov
AWEC	
JESSE O GORSUCH DAVISON VAN CLEVE, PC 1750 SW HARBOR WAY STE 450 PORTLAND OR 97201 jog@dvclaw.com	BRENT COLEMAN **(C)** **(HC)** DAVISON VAN CLEVE, PC 1750 SW HARBOR WAY STE 450 PORTLAND OR 97201 blc@dvclaw.com
JESSE O GORSUCH **(C)** **(HC)** DAVISON VAN CLEVE 1750 SW HARBOR WAY STE 450 PORTLAND OR 97201 jog@dvclaw.com	
OREGON CITIZENS UTILITY BOARD	
OREGON CITIZENS' UTILITY BOARD 610 SW BROADWAY, STE 400 PORTLAND, OR 97205 dockets@oregoncub.org	JOHN GARRETT OREGON CITIZENS' UTILITY BOARD610 SW BROADWAY STE 400 PORTLAND, OR 97205 john@oregoncub.org
MICHAEL GOETZ OREGON CITIZENS' UTILITY BOARD610 SW BROADWAY, STE 400 PORTLAND, OR 97205 mike@oregoncub.org	
NEWSUN ENERGY	
MARIE P BARLOW NEWSUN ENERGY LLC 550 NW FRANKLIN AVE STE 408 BEND OR 97703 mbarlow@newsunenergy.net	JACOB (JAKE) STEPHENS NEWSUN ENERGY LLC 550 NW FRANKLIN AVE STE 408 BEND OR 97703 jstephens@newsunenergy.net

LESLIE SCHAUER NEW SUN ENERGY LLC 2033 E. SPEEDWAY BLVD, SUITE 200 TUCSON AZ 85719 leslie@newsunenergy.net	
PACIFICORP	
PACIFICORP, DBA PACIFIC POWER 825 NE MULTNOMAH ST, STE 2000 PORTLAND, OR 97232 oregondockets@pacificorp.com	AJAY KUMAR **(C)** **(HC)** PACIFICORP 825 NE MULTNOMAH ST STE 2000 PORTLAND, OR 97232 ajay.kumar@pacificorp.com
MATTHEW MCVEE PACIFIC POWER 825 NE MULTNOMAH ST STE 2000 PORTLAND, OR 97232 matthew.mcvee@pacificorp.com	
SIERRA CLUB	
LEAH BAHRAMIPOUR SIERRA CLUB 2101 WEBSTER STREET SUITE 1300 OAKLAND CA 94612 Leah.bahramipour@sierraclub.org	ROSE MONAHAN SIERRA LCU 2101 WEBSTER ST STE 1300 OAKLAND CA 94612 rose.monahan@sierraclub.org
STAFF	
ROSE ANDERSON (C) PUBLIC UTILITY COMMISSION OF OREGON PO BOX 1088 SALEM OR 97308 rose.anderson@puc.oregon.gov	JP BATMALE (C) PUBLIC UTILITY COMMISSION OF OREGON 201 HIGH ST SE SALEM OR 97301 jp.batmale@puc.oregon.gov
JOHANNA RIEMENSCHNEIDER (C) Oregon Department of Justice BUSINESS ACTIVITIES SECTION 1162 COURT ST NE SALEM OR 97301-4796 johanna.riemenschneider@doj.state.or.us	
RENEWABLE NORTHWEST	
DIANE BRANDT RENEWABLE NORTHWEST 421 SW 6TH AVE STE 1400 PORTLAND OR 97204 diane@renewablenw.org	MAX GREENE RENEWABLE NORTHWEST 421 SW 6TH AVE STE 975 PORTLAND OR 97204 max@renewablenw.org

SWAN LAKE NORTH HYDRO	
MICHAEL ROONEY RYE DEVELOPMENT 830 ZNE HOLLADAY ST PORTLAND OR 97232 michael@ryedevelopment.com	ERIK STEIMLE SWAN LAKE NORTH HYDRO LLC 220 NW 8TH AVE PORTLAND OR 97209 erik@ryedevelopment.com
CHRIS ZENTZ VAN NESS FELDMAN LLP cdz@vnf.com	

Dated this 31st day of May, 2023.

Santiago Gutierrez
Coordinator, Regulatory Operations

CERTIFICATE OF SERVICE

I certify that I delivered a true and correct copy of PacifiCorp's **Jim Bridger Long Term Fuel Plan** on the parties listed below via electronic mail in compliance with OAR 860-001-0180.

Service List
UE 420

AWEC	
BRENT COLEMAN **(C)** **(HC)** DAVISON VAN CLEVE, PC 1750 SW HARBOR WAY STE 450 PORTLAND OR 97201 blc@dvclaw.com	
CALPINE SOLUTIONS	
GREGORY M. ADAMS **(C)** RICHARDSON ADAMS, PLLC 515 N 27th ST BOISE ID 83702 greg@richardsonadams.com	GREG BASS CALPINE ENERGY SOLUTIONS, LLC 401 WEST A ST, STE 500 SAN DIEGO CA 92101 greg.bass@calpinesolutions.com
KEVIN HIGGINS **(C)** ENERGY STRATEGIES LLC 215 STATE ST - STE 200 SALT LAKE CITY UT 84111-2322 khiggins@energystrat.com	
OREGON CITIZENS UTILITY BOARD	
OREGON CITIZENS' UTILITY BOARD 610 SW BROADWAY, STE 400 PORTLAND, OR 97205 dockets@oregoncub.org	MICHAEL GOETZ **(C)** **(HC)** OREGON CITIZENS' UTILITY BOARD 610 SW BROADWAY STE 400 PORTLAND, OR 97205 mike@oregoncub.org
ROBERT JENKS **(C)** **(HC)** OREGON CITIZENS' UTILITY BOARD 610 SW BROADWAY, STE 400 PORTLAND, OR 97205 bob@oregoncub.org	
KWUA	
KLAMATH BASIN WATER USER PROTECTIVE ASSOCIATION 2312 SOUTH SIXTH STREET, STE A KLAMATH FALLS OR 97601 assist@kwua.org	PAUL S SIMMONS **(C)** **(HC)** SOMACH SIMMONS & DUNN 500 CAPITOL MALL STE 1000 SACRAMENTO CA 95814 psimmons@somachlaw.com

PACIFICORP	
PACIFICORP, DBA PACIFIC POWER 825 NE MULTNOMAH ST, STE 2000 PORTLAND, OR 97232 oregondockets@pacificorp.com	AJAY KUMAR **(C)** **(HC)** PACIFICORP 825 NE MULTNOMAH ST STE 2000 PORTLAND, OR 97232 ajay.kumar@pacificorp.com
SIERRA CLUB	
LEAH BAHRAMIPOUR SIERRA CLUB 2101 WEBSTER STREET SUITE 1300 OAKLAND CA 94612 Leah.bahramipour@sierraclub.org	ROSE MONAHAN **(C)** **(HC)** SIERRA LCU 2101 WEBSTER ST STE 1300 OAKLAND CA 94612 rose.monahan@sierraclub.org
STAFF	
STEPHANIE S ANDRUS **(C)** **(HC)** PUC STAFF - DEPARTMENT OF JUSTICE 1162 COURT ST NE SALEM, OR 97301 stephanie.andrus@doj.state.or.us	
VITESSE LLC	
DENNIS BARTLETT **(C)** META PLATFORMS INC 1 HACKER WAY MENLO PARK CA 94025 dbart@fb.com	LIZ FERRELL **(C)** META PLATFORMS INC 1 HACKER WAY MENLO PARK CA 94025 eferrell@fb.com
IRION SANGER **(C)** SANGER LAW PC 4031 SE HAWTHORNE BLVD PORTLAND OR 97214 irion@sanger-law.com	

Dated this 31st day of May, 2023.

Santiago Gutierrez
Coordinator, Regulatory Operations

Docket No. UE 420
Exhibit PAC/600
Witness: Zepure Shahumyan

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Reply Testimony of Zepure Shahumyan

July 2023

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I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or Company).

A. My name is Zepure Shahumyan. My business address is 825 NE Multnomah, Suite 2000, Portland, Oregon 97232. I am employed by PacifiCorp as the Director of Energy and Environmental Policy.

Q. Please describe your education and business experience.

A. I have a Bachelor of Science in Biochemistry from Portland State University. I have been employed by PacifiCorp since 2017, initially as a net power cost (NPC) specialist, and for the last five years in Environmental Policy and Strategy functions. Prior to PacifiCorp, I worked for the Bonneville Power Administration from 2010 in various positions of responsibility including enterprise risk management consulting and utility management strategy.

Q. Please explain your responsibilities as PacifiCorp's Director of Energy and Environmental Policy.

A. My current responsibilities include developing PacifiCorp's environmental policy, strategy, and programs to ensure compliance with clean energy laws and regulations including for Company-wide renewable portfolio standards and greenhouse gas (GHG) emissions for California, Oregon, and Washington. I manage PacifiCorp's compliance reporting with the California Air Resources Board Mandatory Reporting

Regulation and Cap and Trade Program. Relevant to this proceeding, I manage PacifiCorp's implementation of Washington's Climate Commitment Act (CCA).[1]

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide a response to the Public Utility Commission of Oregon (Commission) Staff witness Rose Anderson's testimony pertaining to the CCA.[2]

III. BACKGROUND OF THE CCA

Q. What is the CCA, and what is it trying to accomplish?

A. The CCA was signed into Washington law by Governor Inslee on May 17, 2021, and established a cap and invest program for the state that is overseen and implemented by the Washington Department of Ecology (Ecology). The CCA establishes regulatory requirements to reduce carbon emissions in the state.

Q. How does the CCA work?

A. The law attempts to reduce carbon emissions by establishing a market incentive for covered entities to reduce emissions. Generally speaking, the CCA accomplishes this by: (1) setting emissions targets (95 percent below 1990 levels by 2050); (2) establishing an annually decreasing "cap" on the amount of emissions that are permitted in the state (emissions are capped at 93 percent of 2023 baseline emissions, and generally decrease annually until 2050); (3) creating financial instruments for

[1] S.B. 5126, 67th Leg., 2021 Reg. Sess. (Wash. 2021)(codified at RCW 70A.65.005, *et seq*), *available at* https://lawfilesext.leg.wa.gov/biennium/2021-22/Pdf/Bills/Session%20Laws/Senate/5126-S2.SL.pdf?cite=2021%20c%20316%20%C2%A7%201).
[2] Staff/400, Anderson/1–14.

permitted emissions, or "allowed" emissions that fall under the "cap;" and (4) establishing a market for entities to buy, sell, and trade allowances associated with permitted CCA emissions to comply with the emissions limits.

As the emissions cap decreases, the available allowances will decrease, and covered entities will either have to reduce emissions, secure extra allowances, or pursue alternative compliance options.

Q. What entities are obligated to comply with the CCA?

A. Starting January 1, 2023, the CCA applies to industrial facilities, certain fuel suppliers, in-state electricity generators, electricity importers, and natural gas distributors with annual GHG emissions above 25,000 metric tons of carbon dioxide equivalent.[3] The CCA applies to PacifiCorp because it is an in-state electricity generator and electricity importer.

Q. How does the CCA impact the Company's load service in Oregon?

A. The CCA requires that the Company demonstrate compliance by retiring GHG allowances for any GHG emissions output from a thermal generator within the state of Washington even if the energy exports outside the state of Washington.[4] The only source of GHG emitting energy owned by the Company in the state of Washington is the Chehalis gas-fired generation plant (Chehalis). For energy from the Chehalis plant allocated to serve customers outside of Washington there is an associated GHG obligation proportionate to the cost allocation share of Chehalis. Therefore, for all

[3] RCW 70A.65.080(1)(a).
[4] It is possible that exported energy from a Washington thermal generator could be covered by allowances by a "linked" cap and trade program in another state in the future, however, no programs from other states have been "linked" to Washington.

energy allocated to Oregon from the Chehalis plant, the Company applied an incremental dollar-per-megawatt-hour cost based on the GHG allowance price for the test period.

Q. Can you please explain the no-cost allowances within the CCA?

A. The CCA directs Ecology to design and implement a cap and invest program to reduce statewide greenhouse gas emissions. As part of this program, Ecology will distribute no-cost allowances to qualifying electric utilities to mitigate the cost burden of the program to electric utility customers who are also subject to the Clean Energy Transformation Act.[5] The allocation of no-cost allowances to each eligible investor-owned electric utility must be consistent with a four-year forecast of a utility's supply and demand approved by the Washington Utilities and Transportation Commission (WUTC), as well as the cost burden resulting from the inclusion of covered entities in the first compliance period of the CCA.[6]

Q. Has PacifiCorp been granted no-cost allowances?

A. Yes. Ecology granted PacifiCorp no-cost allowances for compliance year 2023 consistent with a four-year forecast of PacifiCorp's supply and demand for its Washington retail service area. This forecast was approved by the WUTC. [7]

[5] RCW 70A.65.120(1).
[6] RCW 70A.65.120(2)(b).
[7] *In the Matter of the Petition of PacifiCorp dba Pacific Power & Light Co., Requesting Approval of Forecasts under RCW 70A.65.120*, WUTC Docket No. UE-220789, Order No. 01 at 5 (Jan. 24, 2023).

Q. Has Ecology interpreted the no-cost allowances to only be allocated to Washington retail load?

A. Yes. In the Concise Explanatory Statement Chapter of the Climate Commitment Act Program,[8] Ecology addressed a comment submitted by PacifiCorp regarding the provision of no-cost allowances for the emissions associated with Washington thermal generation allocated outside the state of Washington.[9] PacifiCorp requested guidance for these allowances to be available not only for Washington customers but also for emissions associated with thermal generation (i.e., Chehalis) allocated to customers in other states. Ecology responded to this comment by stating that the CCA primarily focuses on regulating GHG emissions within the state. As a result, the provisions for no-cost allowances are intended to be allocated to Washington retail load:

> **Summary**: Allowances for cost burden should be provided for exported electricity, not just for electricity that serves Washington customers.
> **Response**: A commenter that is a vertically-integrated utility serving customers in multiple states comments that the cost burden of the program should include all costs associated with the program, including costs associated with a generating resource that is not used solely to serve Washington customers. However, *the plain language of the law and legislative intent is clear that the concept of cost burden relates to how the costs associated with covered emissions are passed on to customers in the State of Washington*. Ecology recognizes that the concept of splitting costs among multiple states is complicated, and that long-standing cost-sharing agreements and protocols exist for regulated utilities serving multiple states and the rule language provides for the application of such protocols. It is expected that those protocols will be applied through the existing

[8] State of Washington, Dep't. of Ecology, Publication 22-02-046, Concise Explanatory Statement Chapter 173-446 WAC Climate Commitment Act Program, (Sept. 2022), *available at:* *https://apps.ecology.wa.gov/publications/documents/2202046.pdf*.
[9] Ecology refers to this allocation as an "export".

> means in the rule language, and that a Washington-specific allocation is possible. (emphasis added). [10]

Q. Can you please summarize the testimony of Staff witness Anderson pertaining to the Washington CCA?

A. Yes. Witness Anderson suggests that the no-cost allowances distributed by Ecology to PacifiCorp should be allocated to Oregon customers based on a System Generation allocation factor. According to Witness Anderson, upon Staff's review of the legislation and rules, there is no explicit requirement stating that these allowances should be exclusively provided to Washington customers. Furthermore, even if Washington law mandates that they should only be allocated to Washington customers, Witness Anderson recommends that the Commission should direct PacifiCorp to deviate from such a law.[11]

Q. Could PacifiCorp allocate no-cost allowances to mitigate the cost burden effect of this program on Oregon customers if the Commission directs PacifiCorp to do so?

A. Allocating the no-cost allowances in this manner is inconsistent with the guidance that PacifiCorp has received from Ecology. Staff's proposal could require this Commission to order the Company to violate explicit guidance received from another state agency. It is essential to emphasize that the Company must comply with all applicable laws, including both Oregon and Washington law, which encompasses the CCA. If the Commission were to issue an order contradicting these legal obligations, it would place the Company in an untenable situation.

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[10] Publication 22-0-046 at 248.
[11] Staff/400, Anderson/14.

Q. Does this conclude your reply testimony?

A. Yes.

Docket No. UE 420
Exhibit PAC/700
Witness: Matthew D. McVee

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Reply Testimony of Matthew D. McVee

July 2023

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I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or Company).

A. My name is Matthew D. McVee and my business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. I am currently employed as Vice President, Regulatory Policy and Operations.

Q. Please describe your education and professional experience.

A. I have a Bachelor of Science Degree in Biology from Lewis and Clark College and a Juris Doctorate Degree from Lewis and Clark Law School. I have provided legal counsel to various clients in regulatory matters at both state regulatory commissions and the Federal Energy Regulatory Commission, and acted as administrative attorney to a commissioner at the Nevada Public Utilities Commission. I joined PacifiCorp in 2005 as senior legal counsel for transmission. I became General Counsel for the Western Electricity Coordinating Counsel in 2008. I rejoined the PacifiCorp legal department in 2013. Before taking my current position, I was Chief Regulatory Counsel for PacifiCorp. My current responsibilities include managing regulatory relations with the California, Oregon, and Washington state regulatory commissions, staffs, and stakeholders; developing regulatory policy strategies for PacifiCorp; and managing PacifiCorp's regulatory discovery and filings group.

II. PURPOSE AND SUMMARY OF TESTIMONY

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

A. I respond to the opening testimony of Bob Jenks, filed on behalf of the Oregon Citizens' Utility Board (CUB).

Q. Please summarize your testimony.

A. I respond to CUB's concerns regarding rate shock and explain that PacifiCorp is dedicated to keeping its rates as low as possible for customers, while still ensuring that the forecasted net power costs (NPC) are as accurate as possible, consistent with long-standing Commission policy. The Company recognizes that current market conditions—which are entirely outside the Company's control—are driving higher NPC and the Company is committed to working to keep costs down where possible. However, denying recovery of prudently incurred costs over rate shock concerns is counter to well established Commission precedent and the purpose of the transition adjustment mechanism (TAM). Delaying recovery of costs that are already included in rates and not at issue in this case goes well beyond the scope of the TAM, is largely unnecessary given customer's access to equal payment plans, and will place financial pressure on PacifiCorp's credit metrics to the ultimate detriment of customers.

III. REPLY TESTIMONY

Q. Please describe CUB's concern related to rate shock.

A. CUB is concerned that the proposed rate increase in this case, coupled with the potential rate increases from the Company's "wildfire mitigation, Power Cost Adjustment Mechanism [PCAM], and other assorted single-issue ratemaking mechanisms" will cause rate shock.[1]

Q. How do you respond to this concern?

A. The Company understands CUB's concern and takes seriously the impact on customers associated with rate increases of any magnitude. In this case, however, the

[1] CUB/100, Jenks/4.

increased rates are largely the product of forces that are outside the Company's control, like current market conditions, and reflective of the costs to serve customers and advance Oregon state energy policies that CUB expressly supports. The purpose of the TAM is to accurately forecast NPC even when that forecast increases rates because of expected market conditions. Furthermore, artificially dampening the costs of power creates inefficient price signals to customers and undermines the potential value of conservation measures and efforts.

Setting accurate NPC is also critical in the TAM because significant under-recovery will lead to rate increases in subsequent years through the PCAM. Indeed, CUB cites the potential rate increase from the PCAM to support its concern over rate shock.[2] To avoid compound rate increases such as the one that is occurring this year because of the under-recovery in 2022, it is essential that NPC be accurately forecast even if the forecast results in a rate increase.

Q. CUB recommends a 15 percent cap on residential rate increases that occur during the winter, like the January 1 rate change associated with the TAM.[3] Is rate shock a reasonable basis for decreasing the NPC forecast in this case in order to limit the residential rate increase to 15 percent?

A. No. I understand that the Commission does not consider rate shock in determining revenue requirement, only in developing rate spread and rate design. For example, in Order No. 01-988 in docket UE 115, the Commission stated that "'[r]ate shock' is not a legal principle; rather, it is a factor the Commission has considered in the rate

[2] CUB/100, Jenks/4.
[3] CUB/100, Jenks/7.

spread and rate design stage of various rate proceedings."[4] The Commission explained, "[r]ate shock is a factor the Commission may, but is not required to, consider in the rate spread and rate design stage of the case. Rate shock plays no role in the first phase of ratemaking—the determination of a utility's revenue requirement."[5]

Q. Has the Commission ever made a rate shock determination by looking at multiple pending cases and summing their results?

A. Not to my knowledge. My understanding is that the Commission has reviewed rate shock issues in a particular rate case—and potential rate design solutions—without considering the impact of a utility's other pending or future filings in that review.[6] Focusing on only the present case is reasonable because the other matters CUB lists as contributing to potential rate shock are outside the scope of the TAM.

[4] *In the Matter of Portland General Electric Company's Proposal to Restructure and Reprice Its Services in Accordance with the Provisions of SB 1149*, Docket No. UE 115, Order No. 01-988, at 5 (Nov. 20, 2001).

[5] *In the Matter of Portland General Electric Company's Proposal to Restructure and Reprice Its Services in Accordance with the Provisions of SB 1149*, Docket No. UE 115, Order No. 01-842, at 4 (rejecting the argument that "regardless of the prudency of the utility's expenditures, rate increases that cause rate shock are not just and reasonable"); see also Order No. 01-988 (discussing rate shock generally); *In the Matter of Pacific Power & Light (dba PacifiCorp), Request for a General Rate Increase*, Docket No. UE 170, Order No. 06-172, at 18 (Apr. 12, 2006) (noting that the Commission "may *mitigate* the impact of rate changes to help avoid rate shock," but applying that authority only to the principle of gradualism in allocating rates among different customer classes) (emphasis added).

[6] *See, e.g.*, *In the Matter of the Application of Portland General Electric Company for an Investigation into Least Cost Plan Plant Retirement*, Docket Nos. DR 10, UE 88, UM 989, Order No. 08-487, at 76 (Sept. 30, 2008) (rejecting the proposal of CUB and Staff to adjust the amount of recovery in other dockets to balance rate shock in the current docket).

Q. CUB is also concerned that the ultimate rate increase in the TAM is unknown when the Commission issues its final order because the decision is based on stale market information.[7] How do you respond to this concern?

A. The Company agrees that forward market prices—which are entirely outside the Company's control—can change dramatically between the Reply Update and the indicative November update that follows the Commission's final order. In this case, the Company is using the June 30 official forward price curve for the Reply Update, which will mitigate CUB's concern to some extent. However, the purpose of the TAM is to accurately forecast NPC and determine the direct access transition adjustments and the accuracy of both requires use of the most up-to-date information available, including up-to-date forward prices.

Q. Does CUB have any specific recommendations in response to its concerns over rate shock?

A. Yes. CUB has two recommendations. First, CUB recommends that the Commission direct PacifiCorp, through a bench request or other mechanism, to provide updated "information" before the Commission issues its final order in the TAM.[8] Although CUB's testimony is not specific, it appears that the updated information it requests would be an updated official forward price curve and, potentially, an updated Aurora run so that the Commission would understand the magnitude of the NPC forecast it was approving in the final order.

[7] CUB/100, Jenks/4.
[8] CUB/100, Jenks/7.

Q. How do you respond to CUB's first recommendation?

A. It is neither feasible nor useful for the Commission to require an NPC update immediately before issuing its final order and then again immediately after issuing the final order as part of the November update, as discussed in more detail in Company witness Ramon Mitchell's testimony.

Moreover, the implication underlying CUB's recommendation appears to be that the Commission would approve a different TAM revenue requirement based on the results of a pre-final-order update. But, as noted above, setting the TAM revenue requirement artificially low to address concerns over rate shock runs directly counter to well established Commission precedent and the purpose of the TAM.

Q. What is CUB's second recommendation?

A. CUB's second recommend is that the Commission "be prepared to suspend the collection of certain single issue cost recovery items during the winter heating season, if necessary, to reduce the impact of the TAM."[9] CUB identifies a list of potential items and clarifies that it is not recommending eliminating cost recovery, only delaying it to keep the overall rate increase on January 1, 2024, to less than 15 percent.

Q. How do you respond to CUB's second recommendation?

A. Again, the Company appreciates CUB's concern over the potential impact of rate increases during the winter heating season. But CUB's recommendation here is far beyond the scope of the TAM. CUB acknowledges that each of the potential cost

[9] CUB/100, Jenks/8.

recovery items that it proposes to suspend are not part of this case,[10] which is why it is unclear how the Commission could adjust a multitude of other rate schedules that are not at issue in this case through a final order in the TAM.

Moreover, the Company is concerned that shifting even more costs into the summer season may provide temporary winter relief but will create its own issues when customers are faced with higher-than-expected summer bills. To the extent that CUB's proposal seeks to smooth out bills over the course of the year, customers can already take advantage of equal payment plans to achieve the same basic outcome. The Company also has a low-income bill assistance program to help alleviate the pressure on low-income customers caused by increasing rates. As of the end of June, PacifiCorp has approximately 30,000 customers enrolled in these programs.

Finally, delaying recovery of prudently incurred costs to serve customers places additional pressure on the Company's credit metrics, which can result in longer-term and potentially more significant customer rate impacts in the future.

Q. Does this conclude your reply testimony?

A. Yes.

[10] CUB/100, Jenks/8.