PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah Street, Suite 2000
Portland, Oregon 97232

February 14, 2024

*VIA ELECTRONIC FILING*

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

**Re: Advice No. 24-002/UE 434—PacifiCorp's 2025 Transition Adjustment Mechanism**

In compliance with ORS 757.205, OAR 860-022-0025, and OAR 860-022-0030, PacifiCorp d/b/a Pacific Power submits for filing the following proposed tariff pages associated with Tariff P.U.C. OR No. 36, which sets forth all rates, tolls, charges, rules, and regulations applicable to electric service in Oregon. PacifiCorp requests an effective date of January 1, 2025.

**A. Description of Filing**

The purpose of the Transition Adjustment Mechanism (TAM) is to update net power costs for 2025 and to set transition credits for Oregon customers who choose direct access in the November open enrollment window. The proposed tariff sheets listed in Section B below are provided in Ms. Ridenour's Exhibit PAC/302. This tariff filing is supported by testimony and exhibits from the following witnesses:

- Ramon J. Mitchell, Manager, Net Power Costs
- James Owen, Senior Vice President, Environmental, Fuels, and Mining
- Judith M. Ridenour, Specialist, Pricing and Cost of Service

**B. Tariff Sheets**

| Tariff Sheet | Schedule | Title |
|---|---|---|
| Nineteenth Revision of Sheet No. 201-1 | Schedule 201 | Net Power Costs – Cost-Based Supply Service |
| Nineteenth Revision of Sheet No. 201-2 | Schedule 201 | Net Power Costs – Cost-Based Supply Service |
| Nineteenth Revision of Sheet No. 201-3 | Schedule 201 | Net Power Costs – Cost-Based Supply Service |

PacifiCorp will file changes to the transition adjustment tariffs—Schedules 294, 295, and 296—along with any needed changes to Schedule 293 – New Large Load Direct Access Program and Schedule 220 – Standard Daily Offer once the final TAM rates have been posted and are known. The final TAM rates will be established in November, just before the open enrollment window.

**C. Requirements of OAR 860-022-0025 and OAR 860-022-0030**

To support the proposed rates and meet the requirements of OAR 860-022-0025 and OAR 860-022-0030, PacifiCorp provides the description and support indicated in Section A above. Please refer to the exhibits of Ms. Ridenour for the calculation of the proposed rate changes and impacts of proposed price changes by rate schedule.

This proposed change will affect approximately 627,000 customers and would result in an overall annual rate decrease of approximately $18.3 million or 1.0 percent. The average residential customer using 950 kilowatt-hours per month would see a monthly bill decrease of $1.19 per month as a result of this change.

**D. Correspondence**

PacifiCorp respectfully requests that all communications related to this filing be addressed to:

| | |
|---|---|
| Oregon Dockets | Ajay Kumar |
| PacifiCorp | Assistant General Counsel |
| 825 NE Multnomah Street, Suite 2000 | 825 NE Multnomah Street, Suite 2000 |
| Portland, OR 97232 | Portland, OR 97232 |
| oregondockets@pacificorp.com | ajay.kumar@pacificorp.com |

Additionally, PacifiCorp requests that all data requests regarding this matter be addressed to:

| | |
|---|---|
| By e-mail (preferred): | datarequest@pacificorp.com |
| By regular mail: | Data Request Response Center<br>PacifiCorp<br>825 NE Multnomah Street, Suite 2000<br>Portland, OR 97232 |

Please direct informal correspondence and questions regarding this filing to Cathie Allen at (503) 813-5934.

A copy of this filing has been served on all parties to PacifiCorp's 2024 TAM proceeding, docket UE 420. Confidential material in support of the filing has been provided to parties under Order No. 23-132. Highly confidential material in support of this filing has been provided to parties under Order No. 24-033.

Sincerely,

Matthew McVee
Vice President, Regulatory Policy and Operations

Enclosures

Cc: UE 420 Service List

## CERTIFICATE OF SERVICE

I certify that I delivered a true and correct copy of **PacifiCorp's 2025 Transition Adjustment Mechanism** on the parties listed below via electronic mail in compliance with OAR 860-001-0180.

**Service List**
**UE 420**

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Dated this 14th day of February, 2024.

Carrie Meyer

Carrie Meyer
Advisor, Regulatory Operations

**REDACTED**
Docket No. UE 434
Exhibit PAC/100
Witness: Ramon J. Mitchell

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**REDACTED**
Direct Testimony of Ramon J. Mitchell

February 2024

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## ATTACHED EXHIBITS

## 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 Ramon J. Mitchell, and my business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My title is Manager, Net Power Costs.

**Q. Please describe your education and professional experience.**

A. I received a Master of Business Administration degree from the University of Portland and a Bachelor of Arts degree in Economics from Reed College. I was first employed by the Company in 2015 and during my time at the Company I have held various positions in the regulation, merchant, and transmission departments. After a brief departure from the Company, in 2022 I returned to the Company and now serve as Manager, Net Power Costs. In my current role I am responsible for leading and overseeing various efforts associated with the Company's net power costs (NPC) filings.

**Q. Have you testified in previous regulatory proceedings?**

A. Yes. I have previously provided testimony to the Public Utility Commission of Oregon (Commission), as well as commissions in California, Washington, and Wyoming.

## II. PURPOSE OF TESTIMONY

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

A. I present the Company's proposed 2025 Transition Adjustment Mechanism (TAM) NPC. Specifically, my testimony:

- Defines NPC and summarizes the content of the filing;

- Describes the NPC forecast in the 2025 TAM compared to actual NPC in calendar year 2023;
- Describes changes the Company is proposing in this TAM filing; and
- Provides an update on provisions from prior Commission orders.

**Q. Please identify the other Company witnesses supporting the 2025 TAM.**

A. Two additional Company witnesses provide testimony supporting the Company's filing. James Owen, Vice President, Environmental, Fuels and Mining, provides testimony supporting the coal fuel costs and supply included in the 2025 TAM. Judith M. Ridenour, Regulatory Specialist, Pricing & Cost of Service, presents the Company's proposed prices and tariffs and provides a comparison of existing and estimated customer rates.

## III. SUMMARY OF THE COMPANY'S 2025 TAM FILING

**Q. Please explain NPC.**

A. NPC are the sum of fuel expenses, wholesale purchase power expenses, and wheeling expenses, less wholesale sales revenue.

**Q. How does the TAM relate to NPC?**

A. In the 2017 TAM Order, the Commission described the TAM and its purpose as follows:

> PacifiCorp's TAM is an annual filing in which PacifiCorp projects the amount of [NPC] to be reflected in customer rates for the following year, as well as to set transition charges for customers electing to move to direct access. The TAM effectively removes regulatory lag for the company because the forecasts are used to adjust rates. For that reason, the accuracy of the forecasts is of significant importance to setting fair, just and reasonable rates. Our

> goal, therefore, is to achieve an accurate forecast of PacifiCorp's [NPC] for the upcoming year.[1]

**Q. Please explain how the Company calculates NPC.**

A. The Company calculates NPC for a future test period based on a forecast using Aurora, which is a production cost model. Aurora simulates the operation of the Company's power system on an hourly basis and provides an hourly forecast of NPC for the future test period.

**Q. Which version of Aurora was used to prepare this initial filing?**

A. The Aurora version used to prepare this initial filing was version 15.0.1005.[2] No other version of Aurora is assured to be able to identically reproduce the NPC proposal in this initial filing.

**Q. Has the Company proposed any modeling changes in the 2025 TAM?**

A. Yes. The Company proposed the following modeling changes in addition to modeling changes proposed in the 2023 and 2024 TAM:

- The NPC forecast will simulate power hedging transactions in order to maintain compliance with PacifiCorp's current Energy Risk Management Policy.
- Multi-stage gas generators (combined cycle gas turbine resources) will further differentiate between operating configurations.
- Emergency purchases will satisfy all system obligation deficits.

**Q. Did the Company provide advance notice to the parties regarding the modeling changes proposed in this case?**

A. Yes. In compliance with the TAM Guidelines, the Company provided notice of

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[1] *In the Matter of PacifiCorp, d/b/a Pacific Power, 2017 Transition Adjustment Mechanism*, Docket No. UE 307, Order No. 16-482 at 2-3 (Dec. 20, 2016).
[2] Specifically, Aurora version 15.0.1005.8825 released on December 22, 2023.

changes to the Company's modeling of NPC in the 2025 TAM. This notice was provided on January 12, 2024, and is included as Exhibit PAC/105.

**Q. Has the Company implemented all modeling changes referenced in Exhibit PAC/105?**

A. No. The 'multi-stage gas generators' modeling change was not able to be developed and implemented in time for this TAM's filing deadline.

**Q. What non-precedential changes were raised as issues in the 2024 TAM?[3]**

A. The following non-precedential changes were raised as issues in the 2024 TAM:

- Modeling improvement: wholesale sales market capacity limits (market caps) were based on the four-year historical average of short-term firm balancing and spot sales, differentiated by on and off-peak hours. This was completed consistent with the Commission's continued review of this issue as identified in Order No. 21-379;[4]
- Modeling improvement: the day-ahead/real-time (DA/RT) price component was changed to a percentage of market prices;
- Correction: the day-ahead/real-time (DA/RT) volume component was corrected to remove artificial arbitrage revenue and associated erroneous results.

**Q. Are those changes from the 2024 TAM, referenced above, implemented in this filing?**

A. Yes. As an initial matter, all changes proposed in the 2023 and 2024 TAM are implemented in this filing. More specifically, those changes from the 2024 TAM,

[3] *In the Matter of PacifiCorp d/b/a Pacific Power 2024 Transition Adjustment Mechanism*, Docket No. UE 420, Order No. 23-404, Appendix A at 20 (Oct. 27, 2023).
[4] *In the Matter of PacifiCorp d/b/a Pacific Power 2022 Transition Adjustment Mechanism*, Docket No. UE 390, Order No. 21-379 at 28 (Nov. 1, 2021).

referenced above, have been implemented in this year's filing. Please refer to Exhibit PAC/107 for support of those changes and please refer to Exhibit PAC/108 for the NPC impact of those changes.

**Q. What inputs were updated for this filing?**

A. The Company updated all inputs to the 2025 TAM, including system load, wholesale sales and purchase contracts for electricity, natural gas and wheeling, the official forward price curve (OFPC) market prices for electricity and natural gas, fuel expenses, and the characteristics and availability of the Company's generation facilities.

**Q. What is the date of the OFPC the Company used in this filing?**

A. The Company's filing uses the OFPC dated December 29, 2023.

**Q. Will the Company continue to update the OFPC through the pendency of this proceeding?**

A. Yes. In accordance with the current TAM Guidelines, the Company's reply update will incorporate the most recent OFPC that is available at the time the update is prepared. The November indicative update will incorporate an OFPC from within nine days of the filing, and the November final update will incorporate an OFPC from within seven days of the filing. This ensures that the most up-to-date market information is used in the forecast, providing a more accurate estimate of NPC for the test period.

**Q. Please provide background on the Company's 2025 TAM filing.**

A. The TAM is an annual filing that the Company makes to update its NPC in rates and to set the transition adjustments for direct access customers. Along with the forecast

NPC, the 2025 TAM also includes test period forecasts for: (1) incremental benefits and costs related to the Company's participation in the western energy imbalance market (WEIM) with the California Independent System Operator (CAISO); and (2) renewable energy production tax credits (PTCs).

**Q. What is the total-Company NPC in the TAM for calendar year 2025?**

A. The forecast total-Company NPC for calendar year 2025 is approximately $2.533 billion.[5] This is approximately $55 million lower than the total-Company 2024 NPC forecast of approximately $2.588 billion in the 2024 TAM and approximately $100 million lower than the total-Company 2024 NPC forecast before application of the unspecified monetary adjustment in the 2024 TAM.[6] Further details on the total-Company NPC forecast for 2025 are provided in Exhibit PAC/102.

**Q. What is the increase to the Oregon-allocated NPC and the impact to Oregon rates?**

A. As shown in Exhibit PAC/101, there is a decrease to Oregon-allocated NPC of approximately $66 million and an increase in PTCs (decrease to rates) of approximately $7.6 million. After adjusting for the variance from loads, the 2025 TAM results in a decrease to Oregon rates of approximately $18 million. Unless otherwise specified, references to NPC throughout my testimony are expressed on an Oregon-allocated basis. As explained in the testimony of Company witness Ridenour, the 2025 TAM results in an overall average rate decrease of approximately 1.0 percent.

[5] Exhibit PAC/101, Mitchell/1, line 35.
[6] Order No. 23-404, Appendix A at 18.

**Q. Does the proposed rate decrease for the 2025 TAM reflect changes in Oregon load since the 2024 TAM?**

A. Yes. The 2025 load forecast used in the Company's calculation of NPC reflects a decrease in Oregon load compared to the 2024 forecast loads in the 2024 TAM. Due to the decrease in Oregon load, the Company anticipates it will collect approximately $56 million less than what was approved in the 2024 TAM, decreasing the overall requested rate decrease.

**Q. Please explain how the WEIM inter-regional transfer benefits and greenhouse gas benefits are treated in the 2025 TAM.**

A. The Company's initial filing includes a forecast of both the inter-regional transfer benefits and greenhouse gas (GHG) benefits from participation in the WEIM. The expected incremental inter-regional WEIM transfer benefits relative to the optimized NPC modeled by Aurora are reflected as a reduction to the NPC forecast. The total-Company inter-regional WEIM transfer benefits included in the 2025 TAM are [redacted], a [redacted] of [redacted] from the 2024 TAM. The WEIM GHG benefits are [redacted], a [redacted] from the 2024 TAM.

## IV. NPC VALIDATION

**Q. Is $2.533 billion a reasonably accurate forecast for total-Company NPC?**

A. Yes. Preliminary data indicates that 2023 Actual NPC is $2.552 billion. In 2025, as compared to 2023:

(1) For comparison purposes, 2025 Forecast NPC with the inclusion of the Washington Cap and Invest Program is $2.592 billion, or $38.95/megawatt-hour (MWh). 2023 Actual NPC with the inclusion of the Washington Cap

and Invest Program is $2.552 billion, or $41.30/MWh;

(2) 2025 Pacific Northwest summer and winter peak power prices **increase** by 23 percent and Desert Southwest summer and winter peak power prices **increase** by 25 percent;

(3) 2025 Pacific Northwest summer and winter natural gas prices **increase** by 41 percent and Rocky Mountain region summer and winter natural gas prices **increase** by 13 percent (both calculations excluding the anomalous January 2023 price excursion);[7] and

(4) New Company-owned wind is estimated to increase total-Company wind generation by 1.7 million MWh, as compared to 2023. However, load increases by 4.8 million MWh at the total-Company level, as compared to 2023. This increase in load completely absorbs the increased wind generation. After subtracting the wind generation increase from the load increase, the remaining load increase is 3.1 million MWh.

These fundamentals indicate that 2025 total-Company NPC will be higher than 2023 total-Company NPC. All else equal, the remaining load increase valued at the average NPC of $38.95/MWh suggests that 2025 NPC should be an increase of $121 million relative to 2023 NPC; far more than the $40 million increase implied in this TAM.

**Q. Why are summer and winter prices particularly critical when comparing prices?**

A. Summer and winter peak periods are periods of high customer demand and stressed system conditions. Higher power prices in those periods will produce NPC that is

[7] The Company excluded the outlier data from January 2023 because inclusion of that anomalous price spike skews the comparison of 2023 to 2025 data. However, in the interest of complete analysis for the record, from 2023 to 2025, *January* natural gas prices in the Pacific Northwest and in the Rocky Mountain region decreased by 35 percent and 59 percent respectively.

substantially higher relative to any decrease in NPC that may result from lowered prices in spring and fall months, which have light load and relatively mild system conditions.

## V. DISCUSSION OF NPC CHANGES IN THE TAM

**Q. Please generally describe the changes in this 2025 NPC forecast compared to 2023 Actual NPC.**

A. The increase in 2025 Forecast NPC relative to 2023 Actual NPC is driven by increased purchased power expense, increased natural gas fuel expense, and increased wheeling and other expense. This is partially offset by a reduction in coal fuel expense and an increase in wholesale sales revenue (*which continues to be severely over-estimated*).[8] Table 2 for dollars and Table 3 for energy illustrate the changes in total-Company NPC by category from the 2023 Actual NPC to the 2025 Forecast NPC.

**Table 1: NPC Reconciliation Dollars**

| Net Power Cost Reconciliation | | |
|---|---|---|
| | **($ millions)** | **$/MWh** |
| **2023 Preliminary Actual NPC** | **2,552** | **41.30** |
| | | |
| Increase/(Decrease) to NPC: | | |
| Wholesale Sales Revenue | (169.2) | |
| Purchased Power Expense | 101.5 | |
| Coal Fuel Expense | (27.2) | |
| Natural Gas Fuel Expense | 74.7 | |
| Wheeling and Other Expense | 1.5 | |
| **Total Change to NPC** | **(18.7)** | |
| | | |
| **OR 2025 TAM Forecast** | **2,533** | **38.06** |

[8] Please refer to Confidential Figure 2 and Exhibit PAC/107.

**Table 2: NPC Reconciliation Energy**

| Net Power Cost Reconciliation | | |
|---|---|---|
| | **MWh** | **$/MWh** |
| **2023 Preliminary Actual NPC** | **61,781,764** | **41.30** |
| | | |
| Change to Net System Load: | | |
| Wholesale Sales Increase | (1,728,399) | |
| Purchased Power Increase | 5,579,727 | |
| Coal Generation Decrease | (3,165,956) | |
| Natural Gas Generation Increase | 2,713,506 | |
| Other Generation Increase | 1,365,947 | |
| **Total Change to Net System Load** | **4,764,824** | |
| | | |
| **OR 2025 TAM Forecast** | **66,546,588** | **38.06** |

**Q. Please explain the increase in purchased power expense and the increase in wholesale sales revenue.**

A. The purchased power expense increases in tandem with new power purchase agreements and increased load relative to 2023, offset by the removal of costs related to the Washington Cap and Invest Program. For wholesale sales revenue, Aurora produces unrealistically high wholesale sales revenue,[9] and the increase in wholesale sales revenues reflect this difference between recent 2023 actuals and the current 2025 NPC forecast.

**Q. Please explain the decrease in coal fuel expense and the increase in natural gas fuel expense.**

A. The gas conversion of Jim Bridger units 1 and 2 removes two generating units out of the coal fuel expense category and therefore, the expense decreases. Inversely, natural gas expense increases due to: (1) the gas conversion of Jim Bridger units 1 and 2

[9] Please refer to Confidential Figure 2 and Exhibit PAC/107.

which adds two generating units into the natural gas fuel expense category; and (2) increased load relative to 2023.

**Q. Please explain the increase in wheeling and other expense.**

A. Wheeling expenses reflect historical wheeling expenses supporting recent actual purchased power volumes, which have increased over time.

## VI. MODELING IMPROVEMENTS

**Q. In addition to the modeling improvements proposed in the 2023 TAM and the 2024 TAM, has the Company incorporated any additional modeling improvements into this year's TAM?**

A. Yes. The Company is proposing the following modeling improvements:

- The NPC forecast will simulate power hedging transactions in order to maintain compliance with PacifiCorp's current Energy Risk Management Policy.
- Emergency purchases will satisfy all system obligation deficits.

### A. <u>Hedging Requirements</u>

**Q. Please briefly provide an overview of the Company's power hedging requirements.**

A. The Company revised its risk management policy in 2021 with the specific and stated goal of guiding the front office (energy supply management) to purchase increasing amounts of power in periods with short positions. This is intended to limit the possibility of being short during periods of peak demand and peak pricing. This revised policy imposes power hedge percentage limits that are applied independently to each side of the system,[10] varying by quarter, and escalating as the time to delivery

[10] PacifiCorp West and PacifiCorp East.

of power approaches. The most relevant requirement in relation to the Company's NPC forecast is the requirement that positions be hedged at a level where, on average, a minimum of 75 percent of each month's peak hour is hedged in the first quarter of the future (e.g., in December 2024 this would apply to the first quarter of 2025).

**Q. In its original form, is the NPC forecast in compliance with the Company's power hedging requirements?**

A. No. Aurora has no knowledge of the Company's hedging requirements or how they evolve over time. While some quarters may be in compliance without this modeling improvement, that is coincidental, not an indication that the model intentionally satisfies the requirements imposed by the Company's risk management policy.

**Q. What change was made to align the NPC forecast with the Company's power hedging requirements?**

A. To reflect the fact that the Company will eventually need to hedge each quarter at a minimum average of 75 percent, additional short-term firm transactions are calculated, in quarterly 25 megawatt (MW) energy blocks of heavy or light load hour products, and loaded into the model to ensure that the quarterly average hedge ratio in the peak hour of each month satisfies the policy-dictated minimum requirements for the first quarter. In that way, the inputs to the model are created in a manner which recognizes that all four quarters in the test period will eventually be the first quarter in actual operations and the Company will need to execute forward transactions to satisfy its hedging policy requirements.

**Q. Does this change conform to the realities of actual operations?**

A. Yes. As noted above, each month in the test period will eventually be part of a quarter that needs to be hedged at a minimum average of 75 percent in actual operations, as measured against the peak hour load, by side of system.

**Q. Are these simulated hedge volumes subject to the DA/RT price component?**

A. No. The prices used in the DA/RT price component are created in recognition of the fact that, in actual operations, the Company purchases at prices above the OFPC and sells at prices below the OFPC *in the spot market*; and Aurora's optimization is fundamentally a spot market simulation. Because this modeling update is intended to simulate forward transactions, the prices for the simulated hedges are added to the model with no price adjustment. This is reflective of the Company's transaction history, which indicates that forward hedges are executed at or about the prevailing market price at the time of execution, on average.

**Q. Why was no change made to the NPC forecast for the Company's gas hedging requirements?**

A. Because such a change would have no impact to the NPC forecast. Aurora does not physically balance the gas system, and the impact of gas hedges consists entirely of the mark-to-market (MTM) value of those hedges. Were the Company to simulate gas hedge transactions at expected market prices (i.e., the OFPC), they would show—by definition—no MTM impact and additionally, the associated gas volumes are not modeled in Aurora, so there would be no change to the NPC forecast.

**Q. Please quantify the impact of this modeling improvement.**

A. On an isolated basis, the NPC impact is a $6.3 million increase to Oregon-allocated NPC; $23.2 million total-Company.

**B. Unspecified Purchased Power**

**Q. What is unspecified purchased power within the Company's NPC forecast?**

A. Unspecified purchased power is a simulation of regular firm purchased power, with the caveat that no modeled transmission is required to move the purchased power to the point of delivery.

**Q. How is unspecified purchased power related to the longstanding concept of emergency purchases within the NPC forecast?**

A. Whereas emergency purchases were a modeling technique primarily designed to remedy energy deficits with modeled firm purchased power, unspecified purchased power expands and renames the concept of emergency purchases to remedy energy deficits, ramp capability deficits and capacity deficits with modeled firm purchased power.

**Q. Why are there energy deficits in the NPC forecast that require the longstanding usage of emergency purchases as remedy?**

A. The test period short-term transmission capacity modeled in the NPC forecast is based on a four-year average of historical short-term transmission capacity. However, the load and generation in the NPC forecast is based on actual test period expectations (example, includes upcoming new wind and solar resources).

This creates a mismatched scenario wherein there can be more load or generation than there is transmission to fully satisfy the needs of that load or generation. This mismatch occurs because the short-term transmission capacity required in 2025 will be more than the four-year average of historical short-term transmission capacity after accounting for year-over-year growth in load and generation.

**Q. Why does this renamed unspecified purchased power need to incorporate ramp capability deficits and capacity deficits in addition to energy deficits?**

A. The need for up-dispatchable capacity resources to regulate the supply/demand balance is substantially increased as additional amounts of load, wind resources and solar resources are integrated into the Company's system. Increased energy from firm purchased power is required to free up ramp and capacity on existing up-dispatchable capacity resources to integrate that additional load, wind or solar. However, the modeled short-term transmission capacity lags behind reasonable expectations of test period short-term transmission capacity needs due to the usage of four-year historical averages.

In prior NPC forecasts, the forecast capacity deficits were within reason. However, in this 2025 NPC forecast, these capacity deficits have become unreasonable large and indicative of an unreliable NPC forecast. The use of unspecified purchased power to free up ramp and capacity on existing up-dispatchable capacity resources remedies this problem in this TAM and simultaneously resolves the issue wherein the modeled short term transmission capacity is not reflective of test period expectations in this TAM.

**Q. Is this a new modeling improvement?**

A. No. In the 2023 TAM, emergency purchases were used to satisfy energy deficits, ramp capability deficits and capacity deficits. In the 2024 TAM, emergency purchases were inadvertently deactivated as it relates to the satisfaction of ramp capability deficits and capacity deficits. Since the feature is reactivated in the 2025 TAM, the Company discusses it here in the interest of transparency.

**Q. In the 2023 TAM, please describe the amount of emergency purchases, in dollars and in MWh, along with any energy or capacity deficits.**

A. At the total-Company level, emergency purchases in the 2023 TAM were $74 million total-Company (3.76 percent of NPC) or 0.24 million MWh (0.39 percent of load). Energy obligations were 100 percent satisfied and capacity obligations were [redacted].

**Q. In the 2024 TAM, please describe the amount of emergency purchases, in dollars and in MWh, along with any energy or capacity deficits.**

A. At the total-Company level, emergency purchases in the 2024 TAM were $6.9 million total-Company (0.27 percent of NPC) or 0.023 million MWh (0.034 percent of load). Energy obligations were 100 percent satisfied and capacity obligations were [redacted].

**Q. In this 2025 TAM, please describe the amount of unspecified purchased power (emergency purchases), in dollars and in MWh, along with any energy or capacity deficits.**

A. At the total-company level, unspecified purchased power in this 2025 TAM is $43 million total-Company (1.7 percent of NPC) or 0.18 million MWh (0.26 percent of load). Energy obligations were 100 percent satisfied and capacity obligations were [redacted].

**Q. Without using unspecified purchased power to satisfy capacity deficits in this 2025 TAM what would the amount of unspecified purchased power be, in dollars and in MWh, along with any energy or capacity deficits?**

A. Without using unspecified purchased power to satisfy capacity deficits in this 2025 TAM, at the total-Company level, unspecified purchased power would be \$3.3 million total-Company (0.13 percent of NPC) or 0.014 million MWh (0.020 percent of load). Energy obligations would be 100 percent satisfied and capacity obligations would be [redacted].

**Q. Below what threshold are capacity obligation percentages considered unreliable?**

A. [redacted], then the threshold of reliability has been breached in the unfavorable direction, and the forecasted system should no longer be considered reliable.

**Q. From the information provided, what conclusions can be drawn from the use of unspecified purchased power to resolve capacity deficits?**

A. It enables a reliable NPC forecast. Without the use of unspecified purchased power to resolve capacity deficits, the capacity obligations are [redacted] which is [redacted].

---

11 [redacted]

**Q. Have you renamed all 'emergency purchases' references in the NPC forecast, replacing those references with 'unspecified purchased power'?**

A. No. The naming convention of emergency purchases remains the same within the NPC forecast and supporting workpapers. The renaming to unspecified purchased power is for the purpose of clarity in this testimony.

**Q. What is the NPC impact of allowing unspecified purchased power to satisfy ramp capability deficits and capacity deficits in this 2025 TAM, like it did in the 2023 TAM?**

A. On an isolated basis, the NPC impact is a $1.2 million increase to Oregon-allocated NPC; $4.3 million total-Company.

**C. <u>Non-Precedential Modeling Improvements</u>**

**Q. In Confidential Exhibit PAC/107 you present prior testimony from the 2024 TAM supporting the use of the DA/RT percentile adder and the average of averages market caps methodology. Are there any updates to that testimony?**

A. Yes. First, Confidential Figure 6 in Confidential Exhibit PAC/107 is updated below as Confidential Figure 1 and illustrates the actual historical DA/RT price component contrasted with a hypothetical flat adder, showing that the data supports the percentile adder as accurate. Second, Confidential Figure 11 in Confidential Exhibit PAC/107 is updated below as Confidential Figure 2 and illustrates the 2025 forecast sales as compared to historical actual sales, showing that the data supports the use of a **minimum** of averages approach and does not support a third quartile of averages approach; especially when considering that coal supply shortages are continuing from

2023 into 2025. Please refer to Confidential Exhibit PAC/107 for further evidentiary detail on these issues.

**Confidential Figure 1: DA/RT Percentile Adder**

[redacted]

**Confidential Figure 2: Market Capacity**

[redacted]

## VII. ROUTINE UPDATES

### A. <u>Incomplete Source Data</u>

**Q. What inputs were updated for this filing?**

A. The Company updated all inputs to the 2025 TAM, including wholesale sales and purchase contracts for electricity and natural gas.

**Q. How do wholesale sales and purchase contracts for electricity and natural gas flow into the NPC forecast?**

A. First, the Company's commodity management software records all wholesale sales and purchase contracts for electricity and natural gas that are executed in actual operations. This source data then flows into the NPC forecast for calculation of physical power hedges (physical power transactions), physical gas hedges (physical gas transactions), financial gas hedges (financial gas transactions), market capacity limits (physical power sale transactions), and day-ahead / real-time transactions (spot market physical power transactions).

**Q. How does the NPC forecast account for physical power transactions within the production cost models?**

A. Regarding physical power transactions, the Company executes these transactions across many different trading points in the West (western interconnection). These trading points can be categorized as minor trading points or major trading points. For modeling convenience, the NPC forecast models only the major trading points[12] and then maps all transactions at minor trading points to those major trading points. For example, from an electronic tagging (E-Tag) perspective, the energy associated with a physical power hedge transacted with the Bonneville Power Administration may be received at the minor trading point known as the Bonneville/PacifiCorp transmission interface (BPAT.PACW). Since the NPC forecast only models major trading hubs, this particular hedge would be mapped to the Mid-Columbia major trading hub.

**Q. Why is this mapping process necessary?**

A. For accuracy of the NPC forecast all physical power transactions must be accounted for. However, for simplicity of modeling, all trading points across the West are not accounted for in the Company's production cost model. Therefore, all physical power transactions are mapped to one of the major trading points and all major trading points are modeled in the NPC forecast. This ensures that purchases and sales of

[12] Mid-Columbia, California Oregon Border (COB), Nevada Oregon Border (NOB), Mona, Mead, Four Corners, Palo Verde.

physical power are fully accounted for in the model, across the historical and future data.

**Q. What inconsistencies were observed during the TAM update process?**

A. All physical power hedges and all market capacity limits map all physical power transactions to one of the major trading hubs. However, the day-ahead / real-time transaction mapping was incomplete and did not map a substantial portion of the Company's physical power transactions to one of the major trading hubs.

**Q. How does this inconsistency impact the NPC forecast?**

A. Either the market capacity limits are calculated on too many transactions or the day-ahead / real-time transactions are calculated on too few transactions since there can only be one consistent set of transaction data supporting the NPC forecast. Across both scenarios, the Company's commodity records (source data) for power transactions would effectively reflect two separate official record sources in the same NPC forecast and therefore this would create a known inaccuracy in that NPC forecast.

**Q. What is the remedy for this inaccuracy?**

A. All elements of the NPC forecast must calculate from the same set of source data. Therefore, either all power transactions are mapped to major trading points, or only a defined portion of power transactions are mapped to major trading points. The immediate implication is that power hedges and market capacity limits should use only a portion of the Company's power transactions to calculate, or the day-ahead / real-time transactions should use all of the Company's power transactions to calculate.

**Q. How did the Company remedy this inaccuracy in this initial filing?**

A. The day-ahead / real-time transactions were updated to all of the Company's power transactions.

**Q. What is the NPC impact of updating the day-ahead / real-time transactions to all of the Company's power transactions?**

A. On an isolated basis, the NPC impact is a $4.9 million increase to Oregon-allocated NPC; $18.2 million total-Company.

**Q. What would be the NPC impact of updating the power hedges and market capacity limits to only a portion of the Company's power transactions?**

A. On an isolated basis, the NPC impact would be a $4.8 million increase to Oregon-allocated NPC; $17.7 million total-Company.

**Q. The accuracy of the forecasts is of significant importance to setting fair, just and reasonable rates.[13] Which mapping process is more accurate?**

A. Using all power transactions in all the NPC forecast calculations and mapping all minor trading points to the major trading points, for all calculations, is the only accurate process when considering that the NPC forecast simulates and attempts to replicate the actual operations of the Company's system as if only major trading points existed and this contrasts with actual operations which has both major and minor trading points. Without mapping all power transactions to the major trading points in the NPC model, the NPC forecast will not accurately replicate the actual operation of the Company's system.

[13] Docket No. UE 307, Order No. 16-482 at 2-3 (Dec. 20, 2016).

**Q. How does the 2020 Benchmark Study[14] relate to this mapping process?**

A. The results of the 2020 Benchmark Study shows Aurora producing 2020 NPC that is $58.7 million total-company (or 3.9 percent) less than 2020 Actual NPC. This benchmark study uses all power transactions in all the NPC forecast calculations and maps all minor trading points to the major trading points for all calculations. When the 2020 Benchmark Study uses only a portion of the Company's power transactions for day-ahead / real-time transactions, (discussed above as the inaccurate method), the 2020 Benchmark Study shows Aurora producing 2020 NPC that is $72.2 million total-company (or 4.8 percent) less than 2020 Actual NPC. This is a worsening of the 2020 Benchmark under-forecast by $13.6 million.

## VIII. COMPLIANCE WITH TAM ORDERS

**Q. The 2021 TAM Order describes certain actions that need to be taken prior to the 2025 TAM filing. What are those actions?**

A. In Order No. 20-392, the Commission adopted a stipulation reached between the parties.[15] PacifiCorp agreed to the following:

- Performing an informational model run 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 (to be provided in 15-day workpapers).

[14] Exhibit PAC/106.
[15] *See In the matter of PacifiCorp dba Pacific Power's 2021 Transition Adjustment Mechanism*, Docket No. UE 375, Order No. 20-392 (Oct. 30, 2020).

**Q. Has the Company performed this informational model run?**

A. Yes. The informational model run will be provided with the 15-day workpapers for this filing.

**Q. The 2023 TAM Order describes certain actions that need to be taken prior to the 2025 TAM filing. What are those actions?**

A. In Order No. 22-389, the Commission adopted a stipulation reached between the parties.[16] PacifiCorp agreed to the following:

- PacifiCorp will make best efforts to provide to parties a benchmarking study that uses inputs from 2020 actuals on February 1, 2024.

**Q. Did the Company provide the benchmarking study on February 1, 2024, as requested in the 2023 TAM Order?**

A. Yes. The study was provided and is also attached to this testimony as Exhibit PAC/106. The relevant workpapers are also provided concurrently with this filing.

**Q. The 2024 TAM stipulation had a provision related to a new methodology based around the inclusion of the DA/RT price component in the calculation of Transition Adjustments and Consumer Opt-Out Charges. Is the Company proposing to continue the use of that methodology in this filing?**

A. No, the Company is proposing to use the methodology that was prior to the filing of the 2024 TAM, and in the final 2023 TAM. After discussions with Calpine, it became apparent that there was disagreement on how to interpret the language from the 2024 TAM stipulation. As a result, the Company is proposing to revert to the old method in this TAM and to raise the proposed changes to the calculation of Transition

[16] *See In the matter of PacifiCorp dba Pacific Power's 2023 Transition Adjustment Mechanism*, Docket No. UE 400, Order No. 22-389 (Oct. 25, 2022).

Adjustments and Consumer Opt-Out Charges in the ongoing Direct Access Investigation, docket UM 2024.

**Q. Were there other items that needed to be followed-up on from prior TAM Orders?**

A. Yes. The following Table 3 lists the information that was ordered or agreed to in prior TAM Orders and describes where it has been provided:

**Table 3: Information Requested in Prior Orders**

| Order/Stipulation Requirement | Details |
|---|---|
| The Commission has disallowed Washington Climate Commitment Act (CCA) costs as a state-specific initiative that is properly allocated to Washington under PacifiCorp's Multi-State Process. | Washington CCA costs are removed from the NPC forecast. |
| PacifiCorp affirms that the Schedule 296 calculations used to calculate the Consumer Opt-Out Charge, including all supporting work papers, will be provided consistent with the TAM guidelines, 30 days after filing the TAM. | Will be provided in the 30-day workpapers for this filing. |
| As long as there are coal-fired Jim Bridger units in Oregon rates and they are fueled with coal from Bridger Coal Company, PacifiCorp will provide a copy of the updated annual Bridger Coal Company mine plan along with any alternatives that were also evaluated for PacifiCorp in future TAM filings. | These are provided in PacifiCorp's workpapers associated with this filing. |
| PacifiCorp to hold a workshop with Staff and parties regarding coal supply agreements at the Hunter Plant. | As discussed in Company witness Owen's testimony, this workshop will be held before April 1, 2024. |
| Technical Workshops to cover how the following topics are modeled in Aurora:<br>• **Coal Contracting**<br>• **Coal Dispatch**<br>• **Day-Ahead and Real-Time (DA/RT) Adjustment**<br>• **Wind Forecasting**<br>• **Short-Term Transmission**<br>• **Extended Day-Ahead Market/EIM** | PacifiCorp held these workshops on January 22, 2024, and February 2, 2024. |

## IX. PRODUCTION TAX CREDITS

**Q. Please describe the treatment of renewable energy PTCs in the 2025 TAM.**

A. The 2025 TAM includes changes in projected levels of PTCs. Exhibit PAC/103 shows the forecast level of PTCs for 2025 compared to the level of PTCs established in the 2024 TAM. The forecast value of Oregon-allocated PTCs for the 2025 test period is approximately $86.5 million, which is higher than the $78.8 million included in the 2024 TAM, resulting in a decrease to the 2025 TAM of $7.6 million.

**Q. How are PTCs calculated for the 2025 TAM?**

A. The PTC provides a federal income tax credit for the first 10 years of a renewable energy facility's operation. The PTC is calculated by multiplying the qualifying generation by the current PTC rate of 3.0 cents per kilowatt-hour (kWh), and then grossing-up for taxes.

**Q. Please describe the capacity, capacity factors, generation and PTCs for the wind projects in the 2025 TAM.**

A. As seen in Confidential Table 4 below, on a total-Company basis, the Company-owned wind capacity is 2,585 MW and total forecast generation is 7,977,942 MWh. The total tax-adjusted PTCs on an Oregon-allocated basis are $86.5 million.

**Confidential Table 4: Company-Owned Wind Projects Generation and PTC Data**

| | Total Company | | | | Oregon Allocated | | |
|---|---|---|---|---|---|---|---|
| Plant Name | PTC Value | LGIA Capacity (MW) | LGIA Capacity Factor | Generation (MWH) | Factors CY 2025 | CY 2025 Initial Filing | Revenue Requirement (See Note 1) |
| Glenrock I | [redacted] | 99.0 | [redacted] | [redacted] | 26.884% | [redacted] | [redacted] |
| Glenrock III | [redacted] | 39.0 | [redacted] | [redacted] | 26.884% | [redacted] | [redacted] |
| Goodnoe Hills | [redacted] | 94.0 | [redacted] | [redacted] | 26.884% | [redacted] | [redacted] |
| High Plains | [redacted] | 99.0 | [redacted] | [redacted] | 26.884% | [redacted] | [redacted] |
| Leaning Juniper | [redacted] | 100.5 | [redacted] | [redacted] | 26.884% | [redacted] | [redacted] |
| Marengo I | [redacted] | 156.0 | [redacted] | [redacted] | 26.884% | [redacted] | [redacted] |
| Marengo II | [redacted] | 78.0 | [redacted] | [redacted] | 26.884% | [redacted] | [redacted] |
| McFadden Ridge | [redacted] | 28.5 | [redacted] | [redacted] | 26.884% | [redacted] | [redacted] |
| Seven Mile Hill I | [redacted] | 99.0 | [redacted] | [redacted] | 26.884% | [redacted] | [redacted] |
| Seven Mile Hill II | [redacted] | 19.5 | [redacted] | [redacted] | 26.884% | [redacted] | [redacted] |
| Dunlap | [redacted] | 111.0 | [redacted] | [redacted] | 26.884% | [redacted] | [redacted] |
| Foote Creek I | [redacted] | 41.4 | [redacted] | [redacted] | 26.884% | [redacted] | [redacted] |
| TB Flats Wind | [redacted] | 247.3 | [redacted] | [redacted] | 26.884% | [redacted] | [redacted] |
| Cedar Springs II Wind | [redacted] | 200.0 | [redacted] | [redacted] | 26.884% | [redacted] | [redacted] |
| Ekola Flats Wind | [redacted] | 250.0 | [redacted] | [redacted] | 26.884% | [redacted] | [redacted] |
| Pryor Mountain Wind | [redacted] | 239.8 | [redacted] | [redacted] | 26.884% | [redacted] | [redacted] |
| Foote Creek II Wind | [redacted] | 1.8 | [redacted] | [redacted] | 26.884% | [redacted] | [redacted] |
| Foote Creek III Wind | [redacted] | 24.8 | [redacted] | [redacted] | 26.884% | [redacted] | [redacted] |
| Foote Creek IV Wind | [redacted] | 16.8 | [redacted] | [redacted] | 26.884% | [redacted] | [redacted] |
| Rock Creek I Wind | [redacted] | 190.0 | [redacted] | [redacted] | 26.884% | [redacted] | [redacted] |
| Rock Creek II Wind | [redacted] | 400.0 | [redacted] | [redacted] | 26.884% | [redacted] | [redacted] |
| Rock River I Wind | [redacted] | 50.0 | [redacted] | [redacted] | 26.884% | [redacted] | [redacted] |
| Total Production Tax Credit | $ 242,529,590 | 2,585.4 | | 7,977,942 | | $ 65,202,036 | $ 86,459,483 |

Note 1 - Revenue Requirement represents the PTC amount grossed up for the tax rate.

## X. COMPANY SUPPLY SERVICE ACCESS CHARGE

**Q. What is the Company Supply Service Access Charge?**

A. If a new customer elects new load direct access and then subsequently switches to standard offer or cost-based service, resulting in an increase to rates for existing cost-of-service customers of more than 0.5 percent, the consumer electing to switch to standard offer service or cost-based service will be subject to a four-year forward looking rate adder, the Company Supply Service Access Charge. The 0.5 percent assessment is a reasonable threshold for the Company Supply Service Access Charge that represents a material and significant impact to customers and was acknowledged by the Commission at a public meeting on February 26, 2019.[17]

**Q. How is the Company Supply Service Access Charge calculated?**

A. The Company Supply Service Access Charge is calculated as the incremental difference between the four-year levelized cost of capacity that is calculated for avoided cost and the fixed generation costs, Schedule 200. This calculation fairly assigns the new load direct access consumer that is switching to cost-of-service the additional fixed cost associated with the Company's obligation to serve that consumer less the additional recovery that will be received from that consumer for existing fixed generation in rates. The levelized cost of capacity for the upcoming four years is currently less than the fixed generation costs contained in Schedule 200 and therefore the Company Supply Service Access Charge is $0/MWh.

## XI. COMPLIANCE WITH TAM GUIDELINES

**Q. Did the Company prepare this filing in accordance with the TAM Guidelines adopted by Order No. 09-274, as clarified and amended in later orders?**

A. Yes. The Company has complied with the TAM Guidelines applicable to the initial filing in a TAM.

**Q. Does this filing include updates to all NPC components identified in Attachment A to the TAM Guidelines?**

A. Yes.

[17] *PacifiCorp Schedule 193 New Large Load Direct Access Program*, Docket No. ADV-900, Advice No. 18-010, acknowledged Feb. 26, 2019.

**Q. What workpapers did the Company provide with this filing?**

A. In compliance with Attachment B to the TAM Guidelines, the Company provided access to the Aurora model and workpapers concurrently with this initial filing. Specifically, the Company provided the NPC report workbook and the Aurora project.

**Q. Did the Company provide a step log of model and input changes describing changes to the Company's modeling or inputs that are not considered a standard annual update?**

A. Yes. The Company has provided step logs as Exhibit PAC/104 and Exhibit PAC/108.

**Q. Does this conclude your direct testimony?**

A. Yes.

Docket No. UE 434
Exhibit PAC/101
Witness: Ramon J. Mitchell

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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Exhibit Accompanying Direct Testimony of Ramon J. Mitchell

Oregon-Allocated Net Power Costs

February 2024

**PacifiCorp**
**CY 2025 TAM**
**Initial Filing**

| Line no | | ACCT. | Total Company: UE-420 CY 2024 - Final Filing | Total Company: TAM CY 2025 - Initial Filing | Factor | Factors CY 2024 | Factors CY 2025 Initial Filing | Oregon Allocated: UE-420 CY 2024 - Final Filing | Oregon Allocated: TAM CY 2025 - Initial Filing |
|---|---|---|---|---|---|---|---|---|---|
| 1 | **Sales for Resale** | | | | | | | | |
| 2 | Existing Firm PPL | 447 | - | - | SG | 28.701% | 26.884% | - | - |
| 3 | Existing Firm UPL | 447 | - | - | SG | 28.701% | 26.884% | - | - |
| 4 | Post-Merger Firm | 447 | 405,175,435 | 342,499,323 | SG | 28.701% | 26.884% | 116,291,047 | 92,078,056 |
| 5 | Non-Firm | 447 | - | - | SE | 28.515% | 26.339% | - | - |
| 6 | **Total Sales for Resale** | | 405,175,435 | 342,499,323 | | | | 116,291,047 | 92,078,056 |
| 7 | | | | | | | | | |
| 8 | **Purchased Power** | | | | | | | | |
| 9 | Existing Firm Demand PPL | 555 | 86,374,099 | 32,827,693 | SG | 28.701% | 26.884% | 24,790,581 | 8,825,448 |
| 10 | Existing Firm Demand UPL | 555 | 9,231,955 | 259,816 | SG | 28.701% | 26.884% | 2,649,701 | 69,849 |
| 11 | Existing Firm Energy | 555 | 224,534,172 | 76,775,318 | SE | 28.515% | 26.339% | 64,026,188 | 20,221,942 |
| 12 | Post-merger Firm | 555 | 1,279,286,061 | 1,430,826,027 | SG | 28.701% | 26.884% | 367,173,088 | 384,665,517 |
| 13 | Secondary Purchases | 555 | - | - | SE | 28.515% | 26.339% | - | - |
| 14 | Other Generation Expense | 555 | - | - | SG | 28.701% | 26.884% | - | - |
| 15 | **Total Purchased Power** | | 1,599,426,288 | 1,540,688,854 | | | | 458,639,557 | 413,782,757 |
| 16 | | | | | | | | | |
| 17 | **Wheeling Expense** | | | | | | | | |
| 18 | Existing Firm PPL | 565 | 19,834,453 | 18,876,347 | SG | 28.701% | 26.884% | 5,692,767 | 5,074,747 |
| 19 | Existing Firm UPL | 565 | - | - | SG | 28.701% | 26.884% | - | - |
| 20 | Post-merger Firm | 565 | 138,790,535 | 137,231,864 | SG | 28.701% | 26.884% | 39,834,835 | 36,893,630 |
| 21 | Non-Firm | 565 | 10,923,881 | 11,948,862 | SE | 28.515% | 26.339% | 3,114,958 | 3,147,225 |
| 22 | **Total Wheeling Expense** | | 169,548,868 | 168,057,073 | | | | 48,642,559 | 45,115,602 |
| 23 | | | | | | | | | |
| 24 | **Fuel Expense** | | | | | | | | |
| 25 | Fuel Consumed - Coal | 501 | 534,008,113 | 529,881,928 | SE | 28.515% | 26.339% | 152,273,052 | 139,566,231 |
| 26 | Fuel Consumed - Coal (Cholla) | 501 | - | - | SE | 28.515% | 26.339% | - | - |
| 27 | Fuel Consumed - Gas | 501 | 128,664,879 | 25,127,336 | SE | 28.515% | 26.339% | 36,688,944 | 6,618,319 |
| 28 | Natural Gas Consumed | 547 | 581,913,569 | 590,479,896 | SE | 28.515% | 26.339% | 165,933,350 | 155,527,202 |
| 29 | Simple Cycle Comb. Turbines | 547 | 20,409,678 | 15,687,041 | SE | 28.515% | 26.339% | 5,819,844 | 4,131,828 |
| 30 | Steam from Other Sources | 503 | 4,440,902 | 5,415,246 | SE | 28.515% | 26.339% | 1,266,329 | 1,426,328 |
| 31 | **Total Fuel Expense** | | 1,269,437,142 | 1,166,591,447 | | | | 361,981,518 | 307,269,908 |
| 32 | | | | | | | | | |
| 33 | TAM Settlement Adjustment* | | (45,293,948) | - | | As Settled | | (13,000,000) | - |
| 34 | | | | | | | | | |
| 35 | **Net Power Cost (Per Aurora)** | | 2,587,942,914 | 2,532,838,052 | | | | 739,972,588 | 674,090,210 |
| 36 | | | | | | | | | |
| 37 | Oregon Situs NPC Adustments | | (1,041,320) | (1,482,488) | OR | 100.000% | 100.000% | (1,041,320) | (1,482,488) |
| 38 | **Total NPC Net of Adjustments** | | 2,586,901,595 | 2,531,355,564 | | | | 738,931,268 | 672,607,722 |
| 39 | | | | | | | | | |
| 40 | Production Tax Credit (PTC) | | (274,678,033) | (321,600,127) | SG | 28.701% | 26.884% | (78,836,458) | (86,459,483) |
| 41 | **Total TAM Net of Adjustments** | | 2,312,223,562 | 2,209,755,437 | | | | 660,094,810 | 586,148,239 |
| 42 | | | | | | | | | |
| 43 | | | | | | | | Increase Absent Load Change | (73,946,571) |
| 44 | | | | | | | | | |
| 45 | | | | | | | Oregon-allocated NPC (incl. PTC) Baseline in Rates from UE-420 | $660,094,810 | |
| 46 | | | | | | | $ Change due to load variance from UE-420 forecast | (55,681,947) | |
| 47 | | | | | | | 2025 Recovery of NPC (incl. PTC) in Rates | $604,412,863 | |
| 48 | | | | | | | | | |
| 49 | | | | | | | | **Increase Including Load Change** | **$ (18,264,624)** |
| 50 | | | | | | | | | |
| 51 | *TAM Settlement Filing UE-420 - Agreed to decrease Oregon-allocated NPC by | | | | | | | Add Other Revenue Change | - |
| 52 | $13,000,000. The Ozone Transport Rule impact of $5.5 million Oregon-allocated was | | | | | | | | |
| 53 | included in the NPC modeling. | | | | | | | **Total TAM Increase/(Decrease)** | **$ (18,264,624)** |

Docket No. UE 434
Exhibit PAC/102
Witness: Ramon J. Mitchell

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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Exhibit Accompanying Direct Testimony of Ramon J. Mitchell

Net Power Costs Report

February 2024

**2025 TAM Initial NPC Report**

| | Total | Jan-25 | Feb-25 | Mar-25 | Apr-25 | May-25 | Jun-25 | Jul-25 | Aug-25 | Sep-25 | Oct-25 | Nov-25 | Dec-25 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | $ | | | | | |
| **Special Sales For Resale** | | | | | | | | | | | | | |
| *Long Term Firm Sales* | | | | | | | | | | | | | |
| Black Hills | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Hurricane Sale | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Leaning Juniper Revenue | $ 314,805 | $ 19,374 | $ 18,777 | $ 26,782 | $ 15,938 | $ 19,120 | $ 19,982 | $ 46,183 | $ 49,947 | $ 36,286 | $ 22,444 | $ 18,292 | $ 21,681 |
| PSCo_Sale | $ 13,182,454 | $ 878,915 | $ 812,880 | $ 911,908 | $ 663,180 | $ 676,640 | $ 868,951 | $ 2,190,767 | $ 2,214,464 | $ 2,118,417 | $ 687,033 | $ 444,608 | $ 714,692 |
| **Total Long Term Firm Sales** | $ 13,497,259 | $ 898,289 | $ 831,657 | $ 938,689 | $ 679,118 | $ 695,760 | $ 888,934 | $ 2,236,950 | $ 2,264,411 | $ 2,154,703 | $ 709,476 | $ 462,900 | $ 736,373 |
| *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 | $ 76,498,970 | $ 5,789,034 | $ 4,941,906 | $ 3,379,381 | $ 3,093,666 | $ 3,798,232 | $ 5,325,647 | $ 6,002,999 | $ 9,047,151 | $ 23,247,476 | $ 4,997,101 | $ 2,956,409 | $ 3,919,967 |
| Four Corners | $ 71,608,223 | $ 12,417,428 | $ 6,566,818 | $ 5,799,648 | $ 2,538,042 | $ 1,373,611 | $ 3,001,654 | $ 4,210,271 | $ 4,933,207 | $ 10,869,496 | $ 2,944,709 | $ 7,504,029 | $ 9,449,309 |
| Mead | $ 2,368,762 | $ 4,163,247 | $ (105,037) | $ (101,851) | $ (102,881) | $ (96,413) | $ (95,964) | $ (102,446) | $ 110,115 | $ (105,853) | $ (980,449) | $ (103,946) | $ (109,759) |
| Mid Columbia | $ 115,905,186 | $ 19,518,876 | $ 7,516,189 | $ 8,123,867 | $ 6,816,627 | $ 4,378,140 | $ 4,912,835 | $ 11,604,257 | $ 15,422,633 | $ 8,075,836 | $ 8,709,873 | $ 7,996,988 | $ 12,829,065 |
| Mona | $ 19,578,422 | $ 1,925,654 | $ 1,601,650 | $ 1,412,208 | $ 964,443 | $ 765,769 | $ 1,507,607 | $ 1,478,124 | $ 2,441,843 | $ 2,708,775 | $ 1,051,414 | $ 1,410,034 | $ 2,310,900 |
| NOB | $ 36,578,288 | $ 2,477,566 | $ 3,153,349 | $ 2,240,580 | $ 1,979,324 | $ 2,323,457 | $ 2,302,159 | $ 3,718,921 | $ 5,343,177 | $ 3,831,938 | $ 2,457,459 | $ 3,218,697 | $ 3,531,664 |
| Palo Verde | $ 6,464,213 | $ 409,245 | $ 239,055 | $ 250,915 | $ 326,135 | $ 203,436 | $ 660,600 | $ 523,182 | $ 1,400,814 | $ 749,235 | $ 294,803 | $ 669,283 | $ 737,510 |
| Trapped Energy | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Total System Balancing Sales** | $ 329,002,064 | $ 46,701,049 | $ 23,913,931 | $ 21,104,750 | $ 15,615,356 | $ 12,746,231 | $ 17,614,538 | $ 27,435,307 | $ 38,698,939 | $ 49,376,903 | $ 19,474,910 | $ 23,651,494 | $ 32,668,656 |
| **Total Special Sales For Resale** | $ 342,499,323 | $ 47,599,338 | $ 24,745,588 | $ 22,043,439 | $ 16,294,474 | $ 13,441,990 | $ 18,503,472 | $ 29,672,257 | $ 40,963,349 | $ 51,531,606 | $ 20,184,387 | $ 24,114,394 | $ 33,405,028 |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *Purchased Power & Net Interchange* | | | | | | | | | | | | | |
| *Long Term Firm Purchases* | | | | | | | | | | | | | |
| Appaloosa 1A Solar | $ 10,292,182 | $ 559,723 | $ 593,465 | $ 906,325 | $ 978,713 | $ 1,146,027 | $ 1,210,510 | $ 1,060,453 | $ 1,033,174 | $ 974,493 | $ 775,447 | $ 576,254 | $ 477,599 |
| Appaloosa 1B Solar | $ 6,861,455 | $ 373,148 | $ 395,643 | $ 604,217 | $ 652,475 | $ 764,018 | $ 807,006 | $ 706,969 | $ 688,783 | $ 649,662 | $ 516,964 | $ 384,170 | $ 318,399 |
| Castle Solar UoU | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Castle Solar IHC | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Cedar Springs Wind | $ 11,723,272 | $ 1,348,848 | $ 1,095,201 | $ 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 | $ 8,908,094 | $ 1,025,293 | $ 832,068 | $ 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 | $ 35,181,067 | $ 4,332,908 | $ 3,096,960 | $ 2,854,190 | $ 2,509,530 | $ 2,311,613 | $ 2,072,340 | $ 2,005,125 | $ 2,086,972 | $ 2,345,721 | $ 3,189,306 | $ 3,831,121 | $ 4,545,280 |
| Combine Hills Wind | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Cove Mountain Solar | $ 3,802,638 | $ 182,379 | $ 191,610 | $ 333,997 | $ 363,597 | $ 418,499 | $ 450,080 | $ 436,591 | $ 413,105 | $ 354,252 | $ 285,173 | $ 204,900 | $ 168,457 |
| Cove Mountain Solar II | $ 9,387,257 | $ 450,472 | $ 473,272 | $ 824,965 | $ 898,077 | $ 1,033,683 | $ 1,111,688 | $ 1,078,370 | $ 1,020,362 | $ 874,994 | $ 704,370 | $ 503,256 | $ 413,748 |
| Deseret Purchase | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Eagle Mountain - UAMPS/UMPA | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Elektron Solar 20yr | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Elektron Solar 25yr | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Gemstate | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Graphite Solar | $ 6,197,453 | $ 310,012 | $ 351,184 | $ 554,615 | $ 608,658 | $ 682,657 | $ 700,495 | $ 683,227 | $ 639,131 | $ 572,798 | $ 477,596 | $ 353,010 | $ 264,071 |
| Hermiston Purchase | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Horseshoe Solar | $ 6,072,682 | $ 266,686 | $ 331,075 | $ 499,533 | $ 565,742 | $ 674,491 | $ 746,804 | $ 734,022 | $ 695,525 | $ 578,539 | $ 464,831 | $ 287,300 | $ 228,132 |
| Hunter Solar | $ 6,980,641 | $ 367,456 | $ 416,574 | $ 634,629 | $ 662,343 | $ 755,267 | $ 781,559 | $ 743,007 | $ 698,452 | $ 651,256 | $ 555,766 | $ 394,179 | $ 320,154 |
| Hurricane Purchase | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| MagCorp Buythrough | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| MagCorp Reserves | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Milican Solar | $ 2,973,753 | $ 98,000 | $ 149,553 | $ 229,015 | $ 288,259 | $ 342,133 | $ 372,405 | $ 419,382 | $ 370,578 | $ 298,239 | $ 195,281 | $ 125,077 | $ 85,830 |
| Milford Solar | $ 6,870,872 | $ 347,985 | $ 400,729 | $ 591,100 | $ 657,488 | $ 772,977 | $ 814,984 | $ 725,777 | $ 698,695 | $ 651,754 | $ 525,630 | $ 382,415 | $ 301,336 |
| 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 | $ 1,981,228 | $ 67,243 | $ 102,616 | $ 152,164 | $ 191,528 | $ 227,324 | $ 247,437 | $ 278,650 | $ 246,223 | $ 198,159 | $ 129,751 | $ 83,105 | $ 57,028 |
| Rocket Solar | $ 6,473,420 | $ 294,299 | $ 354,922 | $ 535,304 | $ 606,639 | $ 708,931 | $ 796,698 | $ 816,692 | $ 738,987 | $ 621,305 | $ 472,470 | $ 288,647 | $ 238,526 |
| Sigurd Solar | $ 5,858,273 | $ 306,467 | $ 342,172 | $ 504,657 | $ 550,996 | $ 633,287 | $ 696,030 | $ 647,114 | $ 593,204 | $ 553,821 | $ 449,403 | $ 315,824 | $ 265,298 |
| | | | | | | | | | | | | | |
| Small Purchases east | $ 15,358 | $ 1,275 | $ 1,250 | $ 1,246 | $ 1,247 | $ 1,305 | $ 1,315 | $ 1,327 | $ 1,306 | $ 1,267 | $ 1,261 | $ 1,282 | $ 1,277 |
| Small Purchases west | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Soda Lake Geotherma | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Three Buttes Wind | $ 20,609,802 | $ 2,791,462 | $ 1,807,438 | $ 2,137,611 | $ 1,616,596 | $ 1,426,833 | $ 1,201,939 | $ 808,784 | $ 951,391 | $ 1,185,538 | $ 1,736,755 | $ 2,352,258 | $ 2,593,195 |
| Top of the World Wind | $ 36,087,543 | $ 3,064,969 | $ 2,768,359 | $ 3,064,969 | $ 2,966,099 | $ 3,064,969 | $ 2,966,099 | $ 3,064,969 | $ 3,064,969 | $ 2,966,099 | $ 3,064,969 | $ 2,966,099 | $ 3,064,969 |
| Wolverine Creek Wind | $ 10,693,967 | $ 793,982 | $ 927,710 | $ 1,182,235 | $ 1,086,394 | $ 822,360 | $ 882,132 | $ 698,003 | $ 667,573 | $ 785,474 | $ 866,299 | $ 1,002,522 | $ 979,281 |
| Faraday B Sola | $ 7,312,704 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 176,512 | $ 3,317,436 | $ 2,124,238 | $ 1,694,518 |
| Hornshadow I Solar | $ 4,743,533 | $ - | $ - | $ - | $ - | $ - | $ 36,191 | $ 1,067,525 | $ 980,187 | $ 900,194 | $ 771,362 | $ 539,991 | $ 448,084 |
| Hornshadow II Sola | $ 9,487,066 | $ - | $ - | $ - | $ - | $ - | $ 72,382 | $ 2,135,050 | $ 1,960,374 | $ 1,800,388 | $ 1,542,724 | $ 1,079,981 | $ 896,167 |
| Green River Energy Cente | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Anticline Wind | $ 17,957,893 | $ 2,163,887 | $ 1,666,478 | $ 1,559,965 | $ 1,331,510 | $ 1,135,050 | $ 1,085,959 | $ 1,032,757 | $ 1,092,044 | $ 1,208,912 | $ 1,590,032 | $ 1,906,748 | $ 2,184,552 |
| Boswell Springs Wind | $ 33,509,492 | $ 3,612,555 | $ 3,273,801 | $ 3,165,874 | $ 2,914,066 | $ 2,654,216 | $ 2,240,134 | $ 1,878,535 | $ 1,811,646 | $ 2,082,505 | $ 2,949,429 | $ 3,157,338 | $ 3,769,394 |
| Two River Wind LLC | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Cedar Creek | $ 20,759,802 | $ 1,898,940 | $ 1,671,841 | $ 2,588,474 | $ 1,751,554 | $ 1,837,879 | $ 1,203,586 | $ 1,378,214 | $ 1,091,693 | $ 1,311,073 | $ 2,183,871 | $ 2,128,399 | $ 1,714,280 |
| | | | | | | | | | | | | | |
| OR Schedule 126 CSP | $ 4,237,671 | $ 182,871 | $ 260,795 | $ 249,327 | $ 288,399 | $ 314,166 | $ 447,804 | $ 559,671 | $ 728,663 | $ 380,041 | $ 380,656 | $ 263,121 | $ 182,157 |
| UT Schedule Adjustment | $ (46,985,993) | $ (1,931,736) | $ (2,177,607) | $ (3,602,354) | $ (3,988,685) | $ (4,687,204) | $ (4,616,034) | $ (4,321,032) | $ (4,057,260) | $ (3,691,139) | $ (6,407,647) | $ (4,192,906) | $ (3,312,389) |
| | | | | | | | | | | | | | |
| Long Term Firm Purchases Total | $ 275,886,992 | $ 25,233,613 | $ 21,651,600 | $ 23,713,026 | $ 21,613,861 | $ 20,827,066 | $ 19,963,261 | $ 22,270,821 | $ 21,571,456 | $ 22,212,676 | $ 24,982,826 | $ 25,262,981 | $ 26,583,806 |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Qualifying Facilities | | | | | | | | | | | | | | |
| | QF California | $ 1,314,855 | $ 66,937 | $ 226,676 | $ 239,350 | $ 144,127 | $ 109,511 | $ 127,769 | $ 100,913 | $ 959 | $ 902 | $ 942 | $ 120,265 | $ 176,503 |
| | QF Idaho | $ 7,648,992 | $ 661,629 | $ 512,036 | $ 706,334 | $ 679,667 | $ 649,641 | $ 726,078 | $ 637,195 | $ 583,647 | $ 563,518 | $ 631,737 | $ 634,197 | $ 663,313 |
| | QF Oregon | $ 38,690,180 | $ 2,005,238 | $ 2,478,115 | $ 3,038,383 | $ 3,651,224 | $ 4,470,492 | $ 4,605,799 | $ 4,746,825 | $ 4,245,142 | $ 3,466,096 | $ 3,001,624 | $ 1,723,539 | $ 1,257,702 |
| | QF Utah | $ 5,193,083 | $ 359,100 | $ 351,969 | $ 442,051 | $ 460,302 | $ 588,360 | $ 562,403 | $ 505,280 | $ 461,769 | $ 467,996 | $ 441,471 | $ 323,281 | $ 229,099 |
| | QF Washington | $ 418,875 | $ - | $ 0 | $ - | $ 18,079 | $ 9,844 | $ 66,350 | $ 125,752 | $ 127,291 | $ 54,687 | $ 16,872 | $ - | $ - |
| | QF Wyoming | $ 37,864 | $ 3,348 | $ 3,684 | $ 3,409 | $ 5,781 | $ 2,351 | $ 966 | $ 1,525 | $ 1,513 | $ 2,162 | $ 7,404 | $ 1,169 | $ 4,554 |
| | Biomass One QF | $ 18,193,959 | $ 1,488,124 | $ 1,313,070 | $ 1,441,737 | $ 1,334,117 | $ 1,775,556 | $ 1,726,111 | $ 1,600,718 | $ 1,658,504 | $ 1,630,706 | $ 1,669,783 | $ 1,665,167 | $ 890,365 |
| | Chopin Wind QF | $ 2,023,428 | $ 187,801 | $ 192,540 | $ 164,798 | $ 193,035 | $ 171,201 | $ 175,241 | $ 159,633 | $ 144,262 | $ 129,099 | $ 174,434 | $ 170,787 | $ 160,596 |
| | Chopin Schumann Wind QF | $ 351,109 | $ 28,121 | $ 26,579 | $ 34,448 | $ 32,768 | $ 29,609 | $ 31,270 | $ 26,938 | $ 26,579 | $ 21,389 | $ 25,602 | $ 31,845 | $ 35,960 |
| | DCFP QF | $ 60,506 | $ 7,761 | $ 3,966 | $ 3,959 | $ 2,695 | $ 4,276 | $ 5,214 | $ 32,635 | $ - | $ - | $ - | $ - | $ - |
| | Enterprise Solar I QF | $ 12,267,187 | $ 601,040 | $ 720,571 | $ 950,202 | $ 1,061,953 | $ 1,235,698 | $ 1,360,096 | $ 1,543,255 | $ 1,483,363 | $ 1,166,187 | $ 932,284 | $ 684,588 | $ 527,951 |
| | Escalante Solar I QF | $ 11,345,231 | $ 552,577 | $ 658,440 | $ 855,376 | $ 989,796 | $ 1,170,000 | $ 1,283,060 | $ 1,421,370 | $ 1,365,410 | $ 1,080,151 | $ 852,188 | $ 623,406 | $ 493,457 |
| | Escalante Solar II QF | $ 10,687,741 | $ 517,171 | $ 620,158 | $ 805,851 | $ 930,810 | $ 1,106,171 | $ 1,213,704 | $ 1,357,664 | $ 1,281,865 | $ 1,011,532 | $ 799,148 | $ 583,328 | $ 460,340 |
| | Escalante Solar III QF | $ 10,284,717 | $ 503,513 | $ 606,095 | $ 782,229 | $ 905,316 | $ 1,081,064 | $ 1,183,314 | $ 1,302,622 | $ 1,245,053 | $ 987,764 | $ 731,353 | $ 534,547 | $ 421,846 |
| | ExxonMobil QF | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | Five Pine Wind QF | $ 9,807,039 | $ 605,136 | $ 986,312 | $ 889,628 | $ 912,769 | $ 582,668 | $ 633,064 | $ 734,917 | $ 696,663 | $ 874,751 | $ 865,121 | $ 1,006,632 | $ 1,019,378 |
| | Granite Mountain East Solar QF | $ 10,957,013 | $ 582,027 | $ 670,228 | $ 887,339 | $ 986,790 | $ 1,100,787 | $ 1,246,050 | $ 1,383,394 | $ 1,221,769 | $ 996,421 | $ 798,831 | $ 591,056 | $ 492,320 |
| | Granite Mountain West Solar QF | $ 6,405,060 | $ 363,898 | $ 401,806 | $ 564,864 | $ 102,582 | $ 708,506 | $ 802,518 | $ 880,427 | $ 774,822 | $ 628,699 | $ 500,145 | $ 368,902 | $ 307,891 |
| | Iron Springs Solar QF | $ 11,058,255 | $ 580,491 | $ 651,260 | $ 901,221 | $ 1,002,591 | $ 1,116,100 | $ 1,252,661 | $ 1,375,972 | $ 1,314,789 | $ 1,011,844 | $ 782,619 | $ 581,057 | $ 487,650 |
| | Latigo Wind Park QF | $ 9,642,061 | $ 1,001,258 | $ 875,522 | $ 1,119,964 | $ 896,390 | $ 861,246 | $ 740,800 | $ 681,268 | $ 561,899 | $ 620,915 | $ 802,545 | $ 703,857 | $ 776,396 |
| | Mountain Wind 1 QF | $ 8,809,453 | $ 1,383,421 | $ 1,044,417 | $ 858,588 | $ 680,508 | $ 485,398 | $ 495,144 | $ 408,433 | $ 434,347 | $ 455,797 | $ 667,999 | $ 882,811 | $ 1,012,591 |
| | Mountain Wind 2 QF | $ 13,626,741 | $ 2,000,904 | $ 1,551,179 | $ 1,323,297 | $ 1,051,069 | $ 754,886 | $ 882,707 | $ 752,901 | $ 717,302 | $ 750,963 | $ 992,714 | $ 1,361,006 | $ 1,487,813 |
| | North Point Wind QF | $ 20,944,823 | $ 1,213,451 | $ 2,029,595 | $ 1,892,017 | $ 1,965,975 | $ 1,240,761 | $ 1,369,000 | $ 1,629,801 | $ 1,647,255 | $ 1,985,981 | $ 1,919,597 | $ 2,042,749 | $ 2,008,641 |
| | Oregon Wind Farm QF | $ 12,989,094 | $ 898,361 | $ 1,065,632 | $ 1,025,749 | $ 903,417 | $ 779,972 | $ 734,837 | $ 1,614,122 | $ 1,849,036 | $ 1,273,744 | $ 685,746 | $ 810,605 | $ 1,347,873 |
| | Orchard Wind 1 QF | $ 2,300,207 | $ 171,662 | $ 118,895 | $ 219,195 | $ 256,335 | $ 237,550 | $ 255,707 | $ 223,460 | $ 225,588 | $ 164,749 | $ 147,452 | $ 133,685 | $ 145,928 |
| | Orchard Wind 2 QF | $ 2,300,207 | $ 171,662 | $ 118,895 | $ 219,195 | $ 256,335 | $ 237,550 | $ 255,707 | $ 223,460 | $ 225,588 | $ 164,749 | $ 147,452 | $ 133,685 | $ 145,928 |
| | Orchard Wind 3 QF | $ 2,300,207 | $ 171,662 | $ 118,895 | $ 219,195 | $ 256,335 | $ 237,550 | $ 255,707 | $ 223,460 | $ 225,588 | $ 164,749 | $ 147,452 | $ 133,685 | $ 145,928 |
| | Orchard Wind 4 QF | $ 2,300,207 | $ 171,662 | $ 118,895 | $ 219,195 | $ 256,335 | $ 237,550 | $ 255,707 | $ 223,460 | $ 225,588 | $ 164,749 | $ 147,452 | $ 133,685 | $ 145,928 |
| | Pavant II Solar QF | $ 5,925,816 | $ 240,093 | $ 292,661 | $ 433,619 | $ 501,523 | $ 597,794 | $ 649,155 | $ 825,386 | $ 836,194 | $ 602,169 | $ 430,750 | $ 283,419 | $ 233,053 |
| | Pioneer Wind Park I QF | $ 10,665,762 | $ 1,312,186 | $ 930,260 | $ 1,189,464 | $ 900,854 | $ 712,752 | $ 647,784 | $ 660,578 | $ 679,609 | $ 450,955 | $ 824,756 | $ 1,259,911 | $ 1,096,655 |
| | Power County North Wind QF | $ 6,280,744 | $ 480,893 | $ 628,902 | $ 606,013 | $ 589,784 | $ 414,738 | $ 408,195 | $ 421,060 | $ 418,091 | $ 432,807 | $ 584,802 | $ 596,542 | $ 698,919 |
| | Power County South Wind QF | $ 5,593,002 | $ 424,333 | $ 552,983 | $ 546,660 | $ 548,475 | $ 358,146 | $ 363,818 | $ 371,860 | $ 389,130 | $ 382,558 | $ 511,159 | $ 537,476 | $ 606,404 |
| | Roseburg Dillard QF | $ 2,172,329 | $ 165,887 | $ 216,870 | $ 158,169 | $ 176,875 | $ 259,884 | $ 128,909 | $ 280,331 | $ 184,147 | $ 115,915 | $ 96,035 | $ 139,801 | $ 249,507 |
| | Sage I Solar QF | $ 2,224,685 | $ 79,115 | $ 78,138 | $ 185,750 | $ 201,479 | $ 231,609 | $ 255,841 | $ 332,541 | $ 326,288 | $ 205,038 | $ 152,736 | $ 102,280 | $ 73,871 |
| | Sage II Solar QF | $ 2,223,183 | $ 79,198 | $ 78,231 | $ 185,945 | $ 201,695 | $ 230,934 | $ 256,127 | $ 330,821 | $ 326,646 | $ 204,200 | $ 152,889 | $ 102,691 | $ 73,807 |
| | Sage III Solar QF | $ 1,830,073 | $ 66,690 | $ 65,104 | $ 153,415 | $ 164,218 | $ 189,832 | $ 209,266 | $ 269,677 | $ 266,077 | $ 168,341 | $ 128,126 | $ 86,686 | $ 62,640 |
| | Spanish Fork Wind 2 QF | $ 2,838,511 | $ 227,426 | $ 183,910 | $ 209,400 | $ 165,928 | $ 158,139 | $ 220,651 | $ 302,647 | $ 322,851 | $ 276,043 | $ 250,817 | $ 256,401 | $ 264,297 |
| | Sunnyside QF | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | Sweetwater Solar QF | $ 7,551,390 | $ 252,907 | $ 362,894 | $ 547,261 | $ 667,685 | $ 791,264 | $ 950,104 | $ 1,086,493 | $ 1,005,887 | $ 790,122 | $ 610,411 | $ 290,621 | $ 195,741 |
| | Tesoro QF | $ 238,146 | $ 44,974 | $ 48,055 | $ 32,034 | $ 9,572 | $ 2,010 | $ 2,094 | $ 112 | $ 2,147 | $ 8,605 | $ 8,454 | $ 16,548 | $ 63,539 |
| | Three Peaks Solar QF | $ 9,005,953 | $ 440,505 | $ 495,552 | $ 648,798 | $ 869,356 | $ 938,938 | $ 956,823 | $ 1,133,177 | $ 1,073,990 | $ 854,437 | $ 722,120 | $ 473,055 | $ 399,202 |
| | Threemile Canyon Wind QF | $ 2,044,125 | $ 88,630 | $ 181,791 | $ 159,095 | $ 214,475 | $ 214,548 | $ 244,585 | $ 244,129 | $ 200,458 | $ 142,666 | $ 157,514 | $ 108,629 | $ 87,605 |
| | Utah Pavant Solar QF | $ 7,903,605 | $ 303,631 | $ 331,467 | $ 589,182 | $ 687,333 | $ 823,359 | $ 925,322 | $ 1,069,143 | $ 994,980 | $ 848,770 | $ 615,411 | $ 392,672 | $ 322,334 |
| | Utah Red Hills Solar QF | $ 11,368,151 | $ 478,923 | $ 586,421 | $ 770,305 | $ 1,012,192 | $ 1,183,443 | $ 1,221,668 | $ 1,531,459 | $ 1,436,275 | $ 1,315,574 | $ 797,300 | $ 579,799 | $ 454,792 |
| | Skysol Solar QF | $ 6,470,046 | $ 337,321 | $ 346,440 | $ 521,412 | $ 577,208 | $ 628,554 | $ 807,383 | $ 867,608 | $ 760,039 | $ 566,178 | $ 483,488 | $ 285,341 | $ 289,072 |
| Qualifying Facilities Total | | $ 316,293,614 | $ 21,320,670 | $ 22,845,110 | $ 26,744,097 | $ 27,425,750 | $ 28,720,245 | $ 30,494,714 | $ 33,644,417 | $ 31,968,400 | $ 27,204,680 | $ 24,416,734 | $ 21,491,406 | $ 20,017,389 |
| Mid-Columbia Contracts | | | | | | | | | | | | | | |
| | Douglas - Wells | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | Grant Reasonable | $ (15,474,138) | $ (1,289,511) | $ (1,289,511) | $ (1,289,511) | $ (1,289,511) | $ (1,289,511) | $ (1,289,511) | $ (1,289,511) | $ (1,289,511) | $ (1,289,511) | $ (1,289,511) | $ (1,289,511) | $ (1,289,511) |
| | Grant Meaningful Priority | $ 122,253,785 | $ 10,187,815 | $ 10,187,815 | $ 10,187,815 | $ 10,187,815 | $ 10,187,815 | $ 10,187,815 | $ 10,187,815 | $ 10,187,815 | $ 10,187,815 | $ 10,187,815 | $ 10,187,815 | $ 10,187,815 |
| | Grant Surplus | $ 2,532,591 | $ 211,049 | $ 211,049 | $ 211,049 | $ 211,049 | $ 211,049 | $ 211,049 | $ 211,049 | $ 211,049 | $ 211,049 | $ 211,049 | $ 211,049 | $ 211,049 |
| Mid-Columbia Contracts Total | | $ 109,312,238 | $ 9,109,353 | $ 9,109,353 | $ 9,109,353 | $ 9,109,353 | $ 9,109,353 | $ 9,109,353 | $ 9,109,353 | $ 9,109,353 | $ 9,109,353 | $ 9,109,353 | $ 9,109,353 | $ 9,109,353 |
| Total Long Term Firm Purchases | | $ 701,492,844 | $ 55,663,636 | $ 53,606,062 | $ 59,566,477 | $ 58,148,964 | $ 58,656,664 | $ 59,567,328 | $ 65,024,591 | $ 62,649,209 | $ 58,526,709 | $ 58,508,913 | $ 55,863,740 | $ 55,710,549 |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Storage & Exchange | | | | | | | | | | | | | |
| Rush lake_BESS | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Fremont Solar_BESS | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Green River Energy Center_BESS | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Faraday Solar_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 | $ 16,126,400 | $ 1,934,400 | $ 1,785,600 | $ 1,934,400 | $ - | $ - | $ - | $ 3,536,000 | $ 3,536,000 | $ 3,400,000 | $ - | $ - | $ - |
| Colorado | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Four Corners | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Idaho | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Mead | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Mid Columbia | $ 13,299,800 | $ - | $ - | $ - | $ - | $ - | $ - | $ 4,484,900 | $ 4,484,900 | $ 4,330,000 | $ - | $ - | $ - |
| Mona | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| NOB | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Palo Verde | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| SP15 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Utah | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Washington | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| West Main | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Wyoming | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| #REF! | $ 320,769,133 | $ - | $ - | $ - | $ 21,843,844 | $ 21,309,799 | $ 21,329,713 | $ 43,140,199 | $ 54,364,125 | $ 43,481,816 | $ 35,764,598 | $ 35,204,906 | $ 44,330,133 |
| Total Short Term Firm Purchases | $ 350,195,333 | $ 1,934,400 | $ 1,785,600 | $ 1,934,400 | $ 21,843,844 | $ 21,309,799 | $ 21,329,713 | $ 51,161,099 | $ 62,385,025 | $ 51,211,816 | $ 35,764,598 | $ 35,204,906 | $ 44,330,133 |
| System Balancing Purchases | | | | | | | | | | | | | |
| COB | $ 48,311,221 | $ 1,028,750 | $ 5,683,631 | $ 253,671 | $ 1,926,350 | $ 1,585,632 | $ 2,888,777 | $ 7,875,538 | $ 11,299,755 | $ 4,782,369 | $ 2,458,867 | $ 3,193,716 | $ 5,334,165 |
| Four Corners | $ 44,826,709 | $ 5,353,834 | $ 3,403,343 | $ 2,169,135 | $ 2,255,737 | $ 997,058 | $ 2,366,999 | $ 7,281,940 | $ 4,477,426 | $ 4,608,527 | $ 2,712,561 | $ 4,076,022 | $ 5,124,124 |
| Mead | $ 691,468 | $ 48,172 | $ 79,275 | $ 45,824 | $ 78,494 | $ 92,534 | $ (70,589) | $ 92,534 | $ (9,520) | $ (1,594) | $ 311,781 | $ 92,534 | $ (67,978) |
| Mid Columbia | $ 288,739,647 | $ 46,981,358 | $ 14,833,732 | $ 11,379,015 | $ 17,443,798 | $ 10,849,562 | $ 15,115,058 | $ 43,421,706 | $ 52,078,596 | $ 11,191,703 | $ 18,330,978 | $ 18,924,475 | $ 28,189,666 |
| Mona | $ 40,490,446 | $ 2,966,735 | $ 1,492,713 | $ 1,767,620 | $ 4,613,761 | $ 3,738,366 | $ 4,127,803 | $ 3,818,465 | $ 4,500,688 | $ 2,142,296 | $ 3,999,265 | $ 2,591,257 | $ 4,731,478 |
| NOB | $ 105,870,586 | $ 8,586,674 | $ 7,969,204 | $ 4,507,244 | $ 5,560,745 | $ 5,946,376 | $ 6,070,548 | $ 16,846,783 | $ 17,923,609 | $ 9,159,724 | $ 5,984,875 | $ 8,731,227 | $ 8,583,577 |
| Palo Verde | $ 21,740,200 | $ 5,176,153 | $ 51,677 | $ 27,850 | $ 1,634,211 | $ 1,542,256 | $ 2,132,916 | $ 550,555 | $ 3,885,758 | $ 283,378 | $ 2,239,518 | $ 1,924,528 | $ 2,291,400 |
| EIM Imports/Exports | $ (105,006,963) | $ (10,663,055) | $ (7,929,860) | $ (7,468,004) | $ (6,703,505) | $ (6,232,768) | $ (6,205,000) | $ (11,430,019) | $ (12,526,199) | $ (10,605,732) | $ (6,726,058) | $ (7,557,592) | $ (10,959,173) |
| Emergency Purchases | $ 43,337,363 | $ 10,993 | $ - | $ - | $ 837,739 | $ 52,123 | $ 1,291,757 | $ 17,025,962 | $ 24,064,530 | $ 54,259 | $ - | $ - | $ - |
| Total System Balancing Purchases | $ 489,000,677 | $ 59,489,614 | $ 25,583,714 | $ 12,682,356 | $ 27,647,331 | $ 18,571,141 | $ 27,718,269 | $ 85,483,464 | $ 105,694,643 | $ 21,614,930 | $ 29,311,787 | $ 31,976,167 | $ 43,227,259 |
| Total Purchased Power & Net Interchange | $ 1,540,688,854 | $ 117,087,650 | $ 80,975,377 | $ 74,183,233 | $ 107,640,139 | $ 98,537,604 | $ 108,615,310 | $ 201,669,154 | $ 230,728,878 | $ 131,353,456 | $ 123,585,299 | $ 123,044,814 | $ 143,267,941 |
| Wheeling & U. of F. Expense | | | | | | | | | | | | | |
| Firm Wheeling | $ 165,317,427 | $ 13,668,800 | $ 12,958,778 | $ 12,832,513 | $ 13,316,321 | $ 13,180,802 | $ 14,318,878 | $ 14,339,393 | $ 14,525,152 | $ 14,289,448 | $ 13,531,405 | $ 13,560,532 | $ 14,795,406 |
| C&T EIM Admin fee | $ 2,739,646 | $ 230,970 | $ 222,455 | $ 285,739 | $ 237,139 | $ 241,142 | $ 256,561 | $ 238,944 | $ 221,226 | $ 240,569 | $ 181,475 | $ 188,935 | $ 194,490 |
| ST Firm & Non-Firm | - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Total Wheeling & U. of F. Expense | $ 168,057,073 | $ 13,899,770 | $ 13,181,233 | $ 13,118,252 | $ 13,553,461 | $ 13,421,943 | $ 14,575,438 | $ 14,578,337 | $ 14,746,379 | $ 14,530,017 | $ 13,712,880 | $ 13,749,467 | $ 14,989,896 |
| Coal Fuel Burn Expense | | | | | | | | | | | | | |
| Colstrip | $ 19,768,554 | $ 1,872,244 | $ 1,820,230 | $ 1,896,598 | $ 1,319,568 | $ 548,679 | $ 757,338 | $ 2,109,197 | $ 2,225,861 | $ 1,755,863 | $ 1,834,799 | $ 1,749,095 | $ 1,879,083 |
| Craig | $ 19,102,358 | $ 1,588,586 | $ 1,402,458 | $ 1,594,428 | $ 1,361,278 | $ 1,536,934 | $ 1,711,009 | $ 1,707,776 | $ 1,853,184 | $ 1,833,124 | $ 1,705,421 | $ 1,241,603 | $ 1,566,558 |
| Dave Johnston | $ 56,028,158 | $ 4,666,117 | $ 4,399,188 | $ 4,681,110 | $ 3,129,562 | $ 5,315,874 | $ 4,694,156 | $ 5,393,586 | $ 5,390,788 | $ 5,883,541 | $ 4,260,466 | $ 4,228,394 | $ 3,985,376 |
| Hayden | $ 10,375,880 | $ 884,381 | $ 784,662 | $ 855,071 | $ 825,351 | $ 832,259 | $ 871,403 | $ 961,196 | $ 960,736 | $ 850,723 | $ 550,638 | $ 781,636 | $ 1,217,824 |
| Hunter | $ 162,928,319 | $ 20,208,111 | $ 18,632,452 | $ 9,376,421 | $ 6,641,223 | $ 10,703,012 | $ 10,367,139 | $ 17,191,404 | $ 15,910,726 | $ 10,129,640 | $ 10,025,753 | $ 14,983,350 | $ 18,759,087 |
| Huntington | $ 82,218,000 | $ 10,732,157 | $ 10,327,313 | $ 5,706,649 | $ 3,170,262 | $ 4,837,571 | $ 4,654,372 | $ 8,847,575 | $ 8,590,988 | $ 5,335,508 | $ 3,493,115 | $ 7,868,804 | $ 8,653,685 |
| Jim Bridger | $ 118,954,269 | $ 11,432,675 | $ 10,141,591 | $ 12,168,032 | $ 7,168,414 | $ 5,117,989 | $ 9,187,408 | $ 14,471,218 | $ 14,507,487 | $ 11,153,588 | $ 8,372,194 | $ 8,404,484 | $ 6,829,189 |
| Naughton | $ 36,164,475 | $ 4,206,928 | $ 3,694,431 | $ 2,633,765 | $ 1,405,978 | $ 3,202,983 | $ 3,451,832 | $ 3,606,795 | $ 4,103,564 | $ 2,601,932 | $ 1,897,765 | $ 2,224,134 | $ 3,134,370 |
| Wyodak | $ 24,341,915 | $ 2,152,541 | $ 2,094,836 | $ 2,467,389 | $ 2,021,466 | $ 1,863,777 | $ 1,998,750 | $ 2,377,864 | $ 1,812,862 | $ 2,308,083 | $ 1,568,268 | $ 1,602,943 | $ 2,073,136 |
| Total Coal Fuel Burn Expense | $ 529,881,928 | $ 57,743,739 | $ 53,297,162 | $ 41,379,463 | $ 27,043,101 | $ 33,959,078 | $ 37,693,407 | $ 56,666,612 | $ 55,356,196 | $ 41,852,002 | $ 33,708,419 | $ 43,084,443 | $ 48,098,307 |
| Gas Fuel Burn Expense | | | | | | | | | | | | | |
| Chehalis | $ 98,926,957 | $ 16,690,972 | $ 14,814,758 | $ 8,002,201 | $ 4,717,871 | $ 4,175,687 | $ 2,610,725 | $ 6,872,558 | $ 7,495,618 | $ 7,578,352 | $ 7,196,647 | $ 5,675,972 | $ 13,095,598 |
| Currant Creek | $ 71,432,588 | $ 9,797,208 | $ 7,172,550 | $ 6,522,651 | $ 4,284,211 | $ - | $ 5,779,609 | $ 6,320,580 | $ 6,475,239 | $ 5,904,418 | $ 1,476,089 | $ 7,155,094 | $ 10,544,940 |
| Gadsby | $ 25,127,336 | $ 3,087,244 | $ 2,838,279 | $ 1,745,691 | $ 1,581,291 | $ 1,527,986 | $ 1,473,479 | $ 2,403,885 | $ 2,380,451 | $ 1,298,238 | $ 1,814,154 | $ 1,818,025 | $ 3,158,613 |
| Gadsby CT | $ 15,687,041 | $ 2,089,032 | $ 1,819,153 | $ 961,357 | $ 1,053,750 | $ 1,055,987 | $ 1,028,947 | $ 1,365,392 | $ 1,215,421 | $ 868,967 | $ 1,152,021 | $ 1,261,331 | $ 1,815,683 |
| Hermiston | $ 36,017,802 | $ 5,013,244 | $ 4,462,345 | $ 2,570,573 | $ - | $ 1,596,162 | $ 2,934,897 | $ 3,179,037 | $ 3,302,100 | $ 3,354,777 | $ 1,850,585 | $ 2,550,838 | $ 5,203,244 |
| Jim Bridger - Gas | $ 103,123,779 | $ 9,259,215 | $ 7,124,793 | $ 8,422,509 | $ 6,490,555 | $ 6,549,767 | $ 9,964,787 | $ 12,048,326 | $ 12,610,363 | $ 9,806,280 | $ 7,002,649 | $ 6,028,859 | $ 7,815,675 |
| Lake Side 1 | $ 99,629,572 | $ 13,281,889 | $ 9,754,447 | $ 7,528,746 | $ 5,765,424 | $ 6,138,540 | $ 7,048,134 | $ 7,889,171 | $ 8,311,642 | $ 7,942,699 | $ 7,597,962 | $ 6,741,564 | $ 11,629,354 |
| Lake Side 2 | $ 97,291,060 | $ 5,352,920 | $ 4,792,168 | $ 8,684,870 | $ 6,376,046 | $ 6,954,419 | $ 7,764,934 | $ 9,520,067 | $ 9,393,973 | $ 8,464,043 | $ 8,067,350 | $ 8,655,535 | $ 13,264,734 |
| Naughton - Gas | $ 21,831,664 | $ 3,205,512 | $ 2,736,918 | $ 2,140,500 | $ 272,747 | $ 191,941 | $ 1,266,960 | $ 2,581,309 | $ 3,677,308 | $ 2,228,672 | $ 1,648,992 | $ 883,728 | $ 997,077 |
| Total Gas Fuel Burn | | | | | | | | | | | | | |
| Gas Physical | $ (2,145,401) | $ (767,797) | $ (570,329) | $ (192,708) | $ (37,868) | $ (18,972) | $ (60,818) | $ (147,650) | $ (150,590) | $ (122,783) | $ (75,888) | $ - | $ - |
| Gas Swaps | $ 17,955,035 | $ (4,322,253) | $ (658,420) | $ 6,287,149 | $ 2,902,538 | $ 4,005,781 | $ 3,006,713 | $ 1,241,705 | $ 847,656 | $ 1,554,712 | $ 1,912,816 | $ 3,075,000 | $ (1,898,363) |
| Clay Basin Gas Storage | $ (1,048,150) | $ (485,597) | $ (343,147) | $ (72,273) | $ 51,739 | $ 51,739 | $ 51,739 | $ 51,739 | $ 51,739 | $ 51,739 | $ 51,739 | $ (129,644) | $ (379,659) |
| Pipeline Reservation Fees | $ 47,464,991 | $ 3,909,127 | $ 3,843,157 | $ 3,910,525 | $ 3,957,390 | $ 3,989,178 | $ 3,958,129 | $ 3,986,189 | $ 3,987,498 | $ 3,983,471 | $ 3,989,195 | $ 3,960,364 | $ 3,990,767 |
| Total Gas Fuel Burn Expense | $ 631,294,273 | $ 66,110,716 | $ 57,786,672 | $ 56,511,790 | $ 37,415,695 | $ 36,218,215 | $ 46,828,233 | $ 57,312,309 | $ 59,598,417 | $ 52,913,586 | $ 43,684,312 | $ 47,676,666 | $ 69,237,664 |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Other Generation Expense | | | | | | | | | | | | | |
| Blundell | $ 5,415,246 | $ 426,194 | $ 262,756 | $ 516,438 | $ 417,519 | $ 312,035 | $ 492,113 | $ 481,258 | $ 506,730 | $ 443,381 | $ 508,536 | $ 506,047 | $ 542,238 |
| 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 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Rock Creek 1 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Rock Creek 2 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Rock River 1 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | | | | | | | | | | | | | |
| Integration Charge | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | | | | | | | | | | | | | |
| Total Other Generation Expense | $ 5,415,246 | $ 426,194 | $ 262,756 | $ 516,438 | $ 417,519 | $ 312,035 | $ 492,113 | $ 481,258 | $ 506,730 | $ 443,381 | $ 508,536 | $ 506,047 | $ 542,238 |
| | ================ | ================ | ================ | ================ | ================ | ================ | ================ | ================ | ================ | ================ | ================ | ================ | ================ |
| **Net Power Cost** | **$ 2,532,838,052** | **$ 207,668,732** | **$ 180,757,611** | **$ 163,665,736** | **$ 169,775,441** | **$ 169,006,885** | **$ 189,701,029** | **$ 301,035,413** | **$ 319,973,249** | **$ 189,560,836** | **$ 195,015,059** | **$ 203,947,043** | **$ 242,731,018** |
| | ================ | ================ | ================ | ================ | ================ | ================ | ================ | ================ | ================ | ================ | ================ | ================ | ================ |

**REDACTED**
Docket No. UE 434
Exhibit PAC/103
Witness: Ramon J. Mitchell

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**REDACTED**
Exhibit Accompanying Direct Testimony of Ramon J. Mitchell

Update to Renewable Energy Production Tax Credits

February 2024

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

Docket No. UE 434
Exhibit PAC/104
Witness: Ramon J. Mitchell

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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Exhibit Accompanying Direct Testimony of Ramon J. Mitchell

Net Power Costs Step Log

February 2024

| Oregon TAM 2025 (February Initial Filing) | | Impact ($) | Impact ($) | NPC ($) |
|---|---|---|---|---|
| | | Total Company | Oregon-Allocated | Total Company |
| Steps | | | | |
| S00 | Aurora v14.2.1059 to v15.0.1005 | (632,578) | (170,063) | |
| S01 | Incomplete Source Data | 18,221,710 | 4,898,753 | |
| S02 | Unspecified Purchased Power | 4,360,065 | 1,172,167 | |
| S03 | Hedging Requirements | 23,283,747 | 6,259,639 | |
| | | | | |
| | **2025 TAM NPC Proposal** | | | **2,532,838,052** |
| | | | **$/MWh =** | **38.06** |

Docket No. UE 434
Exhibit PAC/105
Witness: Ramon J. Mitchell

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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Exhibit Accompanying Direct Testimony of Ramon J. Mitchell

January 12, 2024 Notice Letter

February 2024

PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah Street, Suite 2000
Portland, Oregon 97232

January 12, 2024

***VIA ELECTRONIC MAIL***

Attn: Parties to Docket UE 420

**RE: 2025 Transition Adjustment Mechanism – PacifiCorp's Notice of Methodology Changes**

Under the Transition Adjustment Mechanism (TAM) Guidelines, PacifiCorp d/b/a Pacific Power (PacifiCorp or Company) provides this Notice of Methodology Changes for the 2025 TAM. This notice complies with an amendment to the TAM Guidelines adopted by the Public Utility Commission of Oregon (Commission) in Order No. 09-432. This amendment provides that "[t]he Company will provide notice of substantial changes to the methodologies used to calculate the cost elements and other inputs to the Aurora model or to the logic of the Aurora model by March 1st of the year of a stand-alone TAM filing."[1] PacifiCorp anticipates filing the TAM mid-February 2024. As a result, the Company is providing this notice to comply with the pre-filing review requirement and the methodology change notice requirement on January 12, 2024.

PacifiCorp provides notice of the following planned changes to the 2025 TAM:

- The base net power costs forecast will simulate power hedging transactions in order to maintain compliance with PacifiCorp's current Energy Risk Management Policy.

- Multi-stage gas generators (combined cycle gas turbine resources) will further differentiate between operating configurations.

- Emergency purchases will satisfy all system obligation deficits.

PacifiCorp is carrying forward the changes supported in testimony in the 2023 and 2024 TAM (dockets UE 400 and UE 420, respectively) and described as non-precedential in one or more of the settlements to those proceedings. *See* Order No. 22-389, Appendix A at 27 and Order No. 23-404, Appendix A at 20. Since those changes were described in-depth in those proceedings, they are not included in this letter.

Please direct any questions regarding this notice to Cathie Allen, regulatory affairs manager at 503-813-5934.

Sincerely,

Matthew McVee
Vice President, Regulatory Policy and Operations

[1] *In the Matter of PacifiCorp d/b/a Pacific Power 2010 Transition Adjustment Mechanism*, Docket UE 207, Order No. 09-432, Appendix A at 4-5 (Oct. 30, 2009).

## CERTIFICATE OF SERVICE

I certify that I delivered a true and correct copy of PacifiCorp's **2025 Transition Adjustment Mechanism – PacifiCorp's Notice of Methodology Changes** 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)**<br>DAVISON VAN CLEVE, PC<br>1750 SW HARBOR WAY STE 450<br>PORTLAND OR 97201<br>tcp@dvclaw.com | BRENT COLEMAN **(C)** **(HC)**<br>DAVISON VAN CLEVE, PC<br>1750 SW HARBOR WAY STE 450<br>PORTLAND OR 97201<br>blc@dvclaw.com |
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| **CALPINE SOLUTIONS** | |
| GREGORY M. ADAMS **(C)** **(HC)**<br>RICHARDSON ADAMS, PLLC<br>515 N 27th ST<br>BOISE ID 83702<br>greg@richardsonadams.com | GREG BASS<br>CALPINE ENERGY SOLUTIONS, LLC<br>401 WEST A ST, STE 500<br>SAN DIEGO CA 92101<br>greg.bass@calpinesolutions.com |
| KEVIN HIGGINS **(C)**<br>ENERGY STRATEGIES LLC<br>215 STATE ST - STE 200<br>SALT LAKE CITY UT 84111-2322<br>khiggins@energystrat.com | |
| **OREGON CITIZENS UTILITY BOARD** | |
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| ROBERT JENKS **(C)** **(HC)**<br>OREGON CITIZENS' UTILITY BOARD<br>610 SW BROADWAY, STE 400<br>PORTLAND, OR 97205<br>bob@oregoncub.org | |

| **KWUA** | |
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| KWUA KLAMATH WATER USER ASSOCIATION<br>KLAMATH BASIN WATER USER PROTECTIVE ASSOCIATION<br>2312 SOUTH SIXTH ST, STE A<br>KLAMATH FALLS, OR 97601<br>assist@kwua.org | PAUL S SIMMONS **(C)** **(HC)**<br>SOMACH SIMMONS & DUNN<br>500 CAPITOL MALL STE 1000<br>SACRAMENTO CA 95814<br>psimmons@somachlaw.com |
| **PACIFICORP** | |
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| **SIERRA CLUB** | |
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| **STAFF** | |
| STEPHANIE S ANDRUS **(C)** **(HC)**<br>PUC STAFF - DEPARTMENT OF JUSTICE<br>1162 COURT ST NE<br>SALEM, OR 97301<br>stephanie.andrus@doj.state.or.us | |
| **VITESSE LLC** | |
| KYLE MOORE<br>META PLATFORMS INC<br>1 HACKER WAY<br>MENLO PARK CA 94025<br>kyletmoore@meta.com | JONI L SLIGER **(C)** **(HC)**<br>SANGER LAW PC<br>META PLATFORMS INC<br>1 HACKER WAY<br>MENLO PARK CA 94025<br>joni@sanger-law.com |
| IRION SANGER **(C)** **(HC)**<br>SANGER LAW PC<br>4031 SE HAWTHORNE BLVD<br>PORTLAND OR 97214<br>irion@sanger-law.com | |

Dated this 12th day of January, 2024.

Santiago Gutierrez
Coordinator, Regulatory Operations

**REDACTED**
Docket No. UE 434
Exhibit PAC/106
Witness: Ramon J. Mitchell

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**REDACTED**
Exhibit Accompanying Direct Testimony of Ramon J. Mitchell

2020 Benchmark Report

February 2024

PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

February 1, 2024

**Re: UE 400—Benchmarking Study**

In Order No. 22-389, the Commission adopted an all-party stipulation which commits the Company to "make best efforts to provide a second benchmarking study that uses inputs from 2020 actuals on February 1, 2024"[1]

**Results of the Benchmarking Study**

The results of the benchmarking study show that Aurora simulated 2020 historical net power costs (NPC) at $58.7 million less than actual NPC. Aurora estimated total company 2020 NPC to be $1,453 million compared to actual 2020 costs of $1,511 million, an under-forecast of 3.9 percent.

**Confidential Table 1** illustrates a detailed comparison between the benchmarking study and 2020 Actual NPC. Long-term firm sales and long-term firm purchase dollars and megawatt-hours (MWh) are based on actual transactions. Hydroelectric generation and solar generation are based on actual generation. The variance between short-term firm and system balancing sales and purchases is driven by the fact that Aurora balances the system differently than the Company does in actual operations. More specifically, Aurora faces a different set of operational constraints compared to what the Company faces in real time. For example, market liquidity in the benchmarking study is predetermined based on market capacity limits that allow more sales transactions than the Company's historical experience.

It is important to note that the NPC forecast is designed with hourly average inputs. Given a certain set of hourly average input variables, Aurora applies its system balancing logic to meet load and wholesale obligations under the operational constraints assumed in the model. In actual operations, the Company faces a different set of real (moment-to-moment) system constraints, many of which are not able to be fully reflected in Aurora's modeling assumptions. Furthermore, Aurora is not able to forecast thermal dispatch in the same way that PacifiCorp dispatches its thermal plants in real time and Aurora's optimization of the system is perfect which means that after the optimization is complete no net savings can be further achieved by backing down one unit and ramping up another unit.

In actual operations, as a matter of prudence, PacifiCorp seeks to optimize the system. However, in reality, PacifiCorp faces a different set of constraints resulting from actual market conditions, and in real time, system dispatch will choose to balance the system using coal plants, gas plants and system balancing purchases and sales in an order that is feasible to current market conditions. The order of selection of coal plants, gas plants and system balancing purchase and sales results in differences in each resource category compared to the benchmarking study

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[1] In the Matter of PacifiCorp d/b/a Pacific Power, 2023 Transition Adjustment Mechanism, Docket No. UE-400, Order No. 22-389, Appendix A at 6 (October 25, 2022).

results. Consequently, and as shown in **Confidential Table 1** below, the coal and natural gas dispatch (on a MWh basis) in Aurora was approximately one percent more and two percent less than actuals, respectively.

**Confidential Table 1 – Net Power Cost Differential Summary – Benchmark**

**[CONFIDENTIAL BEGINS]**

[redacted]

**[CONFIDENTIAL ENDS]**

**<u>Conclusions</u>**

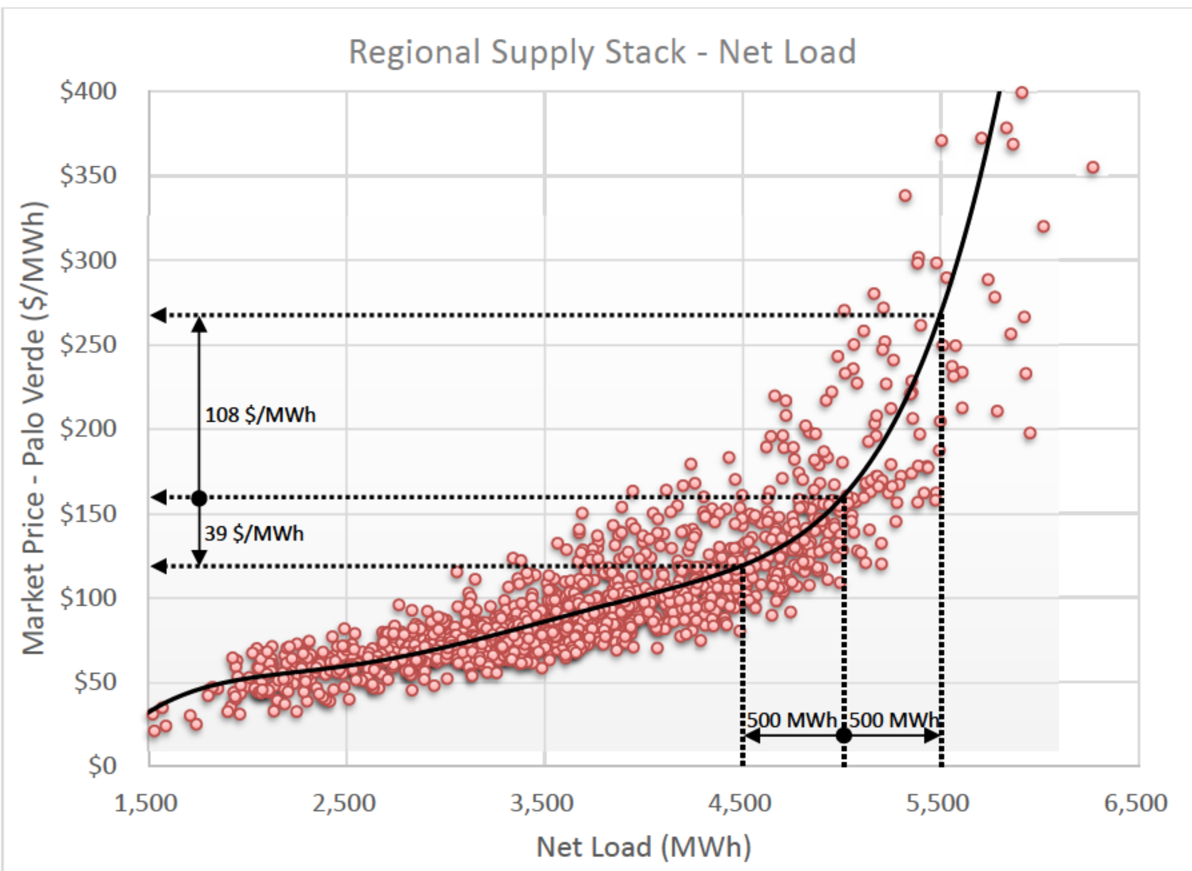
When actual data is used as inputs, Aurora produces 2020 NPC below the actual 2020 NPC and this is to be expected.

Public Utility Commission of Oregon
February 1, 2024
Page 3

First, Aurora applies its system balancing logic with perfect foresight and perfect execution. That is to say, Aurora knows the future and operates the system with perfect efficiency in every hour. In reality, the future is uncertain, humans cannot know exactly at what level variable resources will be producing in a future hour and there will always be some inefficiency within a grouping of individuals (people). In the context of NPC, this reality of the human experience deviates from the perfection inherent in Aurora and the associated perfectly-low Aurora NPC.

Second, there is an asymmetry in the response of market prices to changes in load and generation. As an illustrative example, **Figure 1** below shows a proxy supply/demand curve (with inelastic demand) based on actual load, wind, and solar data within the region. It is observed that because of the asymmetry of market price response, a 500 MWh increase in net load (load less wind less solar) results in a $108 dollar per MWh ($/MWh) increase in market price, whereas an identical 500 MWh decrease in net load results in only a $39/MWh decrease to market price.

**Figure 1**




This asymmetrical response impacts actual operations because the net load forecasts, in reality, are uncertain (i.e., there is no perfect foresight). This uncertainty results in an equal chance of net load being higher or lower than forecasted. However, the impact to NPC is an asymmetric response wherein the actual NPC has a greater chance of being higher than the forecast NPC and consequently the forecast NPC is biased downwards relative to the actual NPC. This result is observed in this benchmarking study.

Confidential information is designated as Protected Information under Order No. 16-128 and may only be disclosed to qualified persons as defined in that order.

**REDACTED**
Docket No. UE 434
Exhibit PAC/107
Witness: Ramon J. Mitchell

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**REDACTED**
Exhibit Accompanying Direct Testimony of Ramon J. Mitchell

DA/RT and Market Caps

February 2024

## 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.

**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**

[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]

[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.

[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

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[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]

[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.

REDACTED



**Confidential Table 5**

[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?**

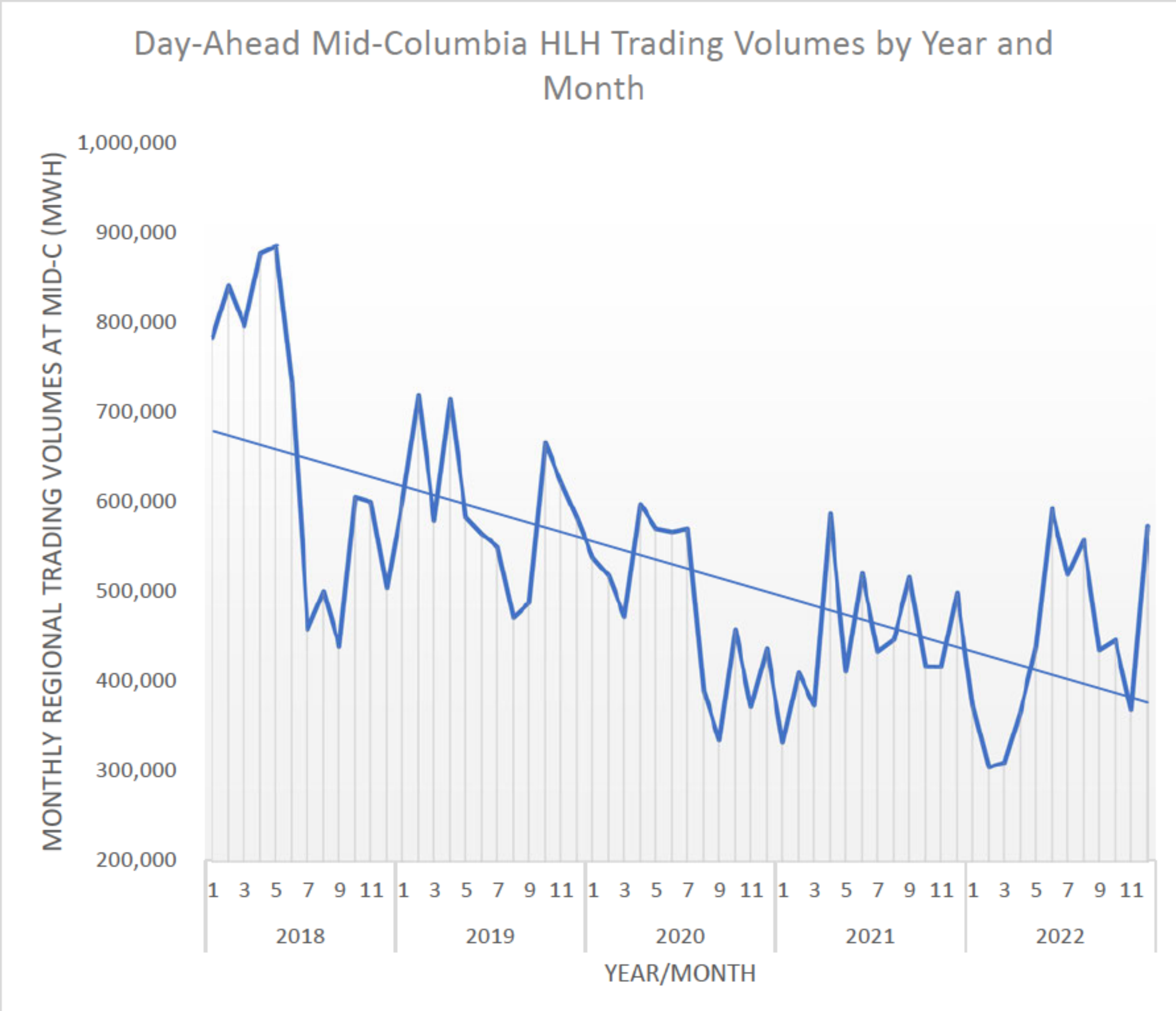
A. No. Staff claims that "there is no true cap to the amount of energy that the Company can sell to or buy from the market hubs."[71] This is untrue. In fact, the Company faces market capacity limits at all its trading hubs. To be clear, market capacity limits refer to the amount of energy that other 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.

[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

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[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.

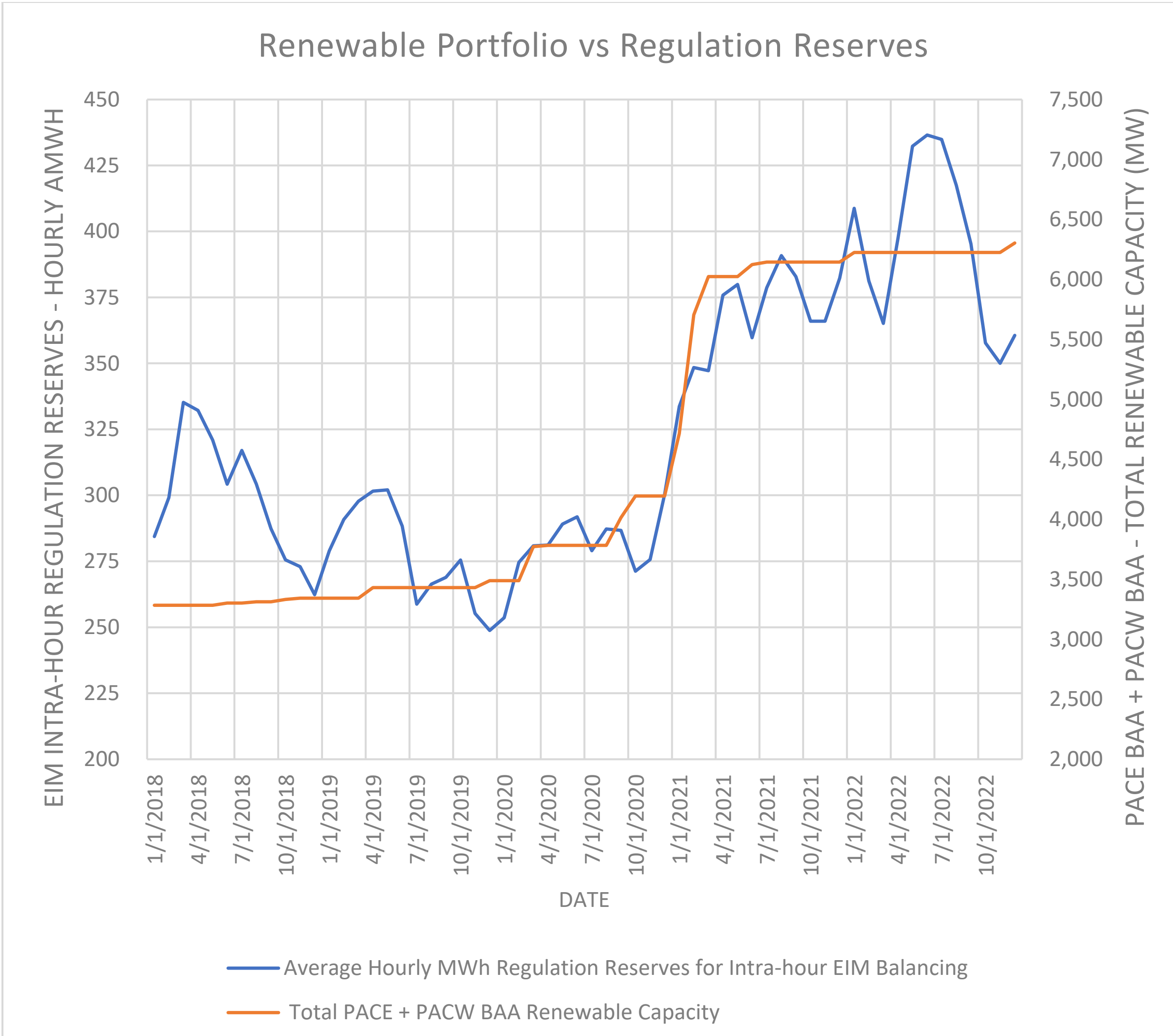
**Q. Why have sales volumes been decreasing across the region, and similarly at the Company, in the day-ahead timeframe?**

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.

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[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.

REDACTED



**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]

[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

[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

[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

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[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.

Docket No. UE 434
Exhibit PAC/108
Witness: Ramon J. Mitchell

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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Exhibit Accompanying Direct Testimony of Ramon J. Mitchell

Non-Precedential Step Log

February 2024

| Oregon TAM 2025 (February Initial Filing) | | Impact ($) | Impact ($) | NPC ($) |
|---|---|---|---|---|
| | | Total Company | Oregon-Allocated | Total Company |
| **Steps** | | | | |
| S01 | DA/RT Percentile Adder | 9,117,381 | 2,451,131 | |
| S02 | Average of Averages Market Caps | 36,892,796 | 9,918,317 | |
| S03 | DA/RT Volume Component Correction | (184,149) | (49,507) | |
| | | | | |
| | **2025 TAM NPC Proposal** | | | **2,532,838,052** |
| | | | **$/MWh =** | **38.06** |

**REDACTED**
Docket No. UE 434
Exhibit PAC/200
Witness: James C. Owen

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**REDACTED**
Direct Testimony of James C. Owen

February 2024

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## ATTACHED EXHIBITS

Highly Confidential Exhibit PAC/201—Hunter/Wolverine CSA Analysis

Confidential Exhibit PAC/202—CSA Contract Minimum Table

## I. INTRODUCTION AND QUALIFICATIONS

**Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company).**

A. My name is James C. Owen. My business address is 1407 West North Temple, Suite 210, Salt Lake City, Utah 84116. My title is Vice President of Environmental, Fuels, and Mining.

**Q. Briefly describe your education and professional experience.**

A. I have a Bachelor of Science Degree in Mining Engineering, a Master of Business Administration Degree, and a Juris Doctor Degree, all from the University of Utah. I joined the Utah Department of Natural Resources – Division of Oil Gas and Mining in November 2008, and held positions of increasing responsibility within the agency, including responsibilities for environmental permitting, enforcement of environmental compliance, engineering design, oversight of mine reclamation bonding, environmental program management, and legislative and policy management. I joined PacifiCorp as Director of Environmental in February 2018. I have assumed positions of increasing responsibility since that time and currently serve as Vice President of Environmental, Fuels, and Mining. My current responsibilities encompass strategic planning, stakeholder engagement, regulatory support, support of major generation resource additions, direct oversight of fueling strategy, management of mining operations, and direct oversight of major environmental compliance projects.

**Q. Have you testified in previous regulatory proceedings?**

A. Yes. I have previously provided testimony on behalf of the Company in proceedings before the Public Utility Commission of Oregon (Commission) and the public utility commissions in California, Idaho, Utah, and Wyoming.

## II. PURPOSE AND SUMMARY

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

A. I explain PacifiCorp's overall approach to providing the coal supply for its coal-fired generating plants, and I support the level of coal costs included in fuel expense in PacifiCorp's 2025 Transition Adjustment Mechanism (TAM). To demonstrate the reasonableness of these costs, my testimony:

- Discusses recent changes in coal market conditions and how those changes impact the 2025 TAM fuel costs;
- Provides details of any new coal supply agreement (CSA) that PacifiCorp entered into since the 2024 TAM that impacts the 2025 TAM;
- Provides an update to its coal pricing and background on third-party coal contracts and affiliate-owned mines; and
- Discusses the Bridger Coal Company (BCC) mine plan analysis for the Jim Bridger plant.

## III. CHANGES IN COAL MARKET CONDITIONS

**Q. What significant changes have occurred in the coal market for PacifiCorp since the 2024 TAM?**

A. The coal market continues to experience similar issues to the ones highlighted in the 2024 TAM filing. The unprecedented increase in coal prices, instability in coal supply and overall market fluctuations continue to cause adverse impacts to PacifiCorp and other large consumers. This negative impact is due to multiple factors, including but not limited to: increased coal demand due to high domestic natural gas prices; low inventories at coal-fired power plants; increased demand abroad for coal exports; international and domestic supply chain constraints; labor and material shortages; weather events and general market inflation.[1]

Specifically, as mentioned in detail in my 2024 TAM direct testimony, the Lila Canyon mine fire removed approximately 25 percent of Utah coal production and disrupted the same portion of PacifiCorp's coal supply needs in Utah.[2] On November 18, 2023, PacifiCorp was informed that the Lila Canyon mine will not reopen and will be permanently closed. The closure of Lila Canyon created a significant coal production shortfall in Utah in 2023 and will continue to have negative impacts to all large consumers, including PacifiCorp, in 2024 and 2025.

In addition to the Lila Canyon mine issues in Utah, coal suppliers continue to experience issues relating to unfavorable geologic and mining conditions, delays and pressure relating to securing federal mining leases, limited availability of trucking and railway transportation for coal, long lead-times for procurement of necessary mining equipment, and limitations in availability of financing, which has put them at an increased risk of becoming insolvent.

**Q. Has the Company experienced any new force majeure claims by its coal suppliers due to the volatile coal market conditions since the 2024 TAM?**

A. Yes. The Company received force majeure claims from two of its major coal suppliers in the latter half of 2023. [redacted]

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[1] *In the Matter of PacifiCorp d/b/a Pacific Power, 2024 Transition Adjustment Mechanism*, Exhibit PAC/200, Owen/3-7 (April 3, 2023).

[2] *In the Matter of PacifiCorp d/b/a Pacific Power, 2024 Transition Adjustment Mechanism*, Exhibit PAC/200, Owen/4 (April 3, 2023).

[redacted] The impact of reduced available coal supplies and higher coal pricing discussed above informed both coal volumes and pricing assumptions in the 2025 TAM.

**Q. Can PacifiCorp use coal supplier force majeure claims to renegotiate contract terms?**

A. [redacted] The Company focuses on achieving its target coal supply at a reasonable price, along with contract terms that provide flexibility. However, in Utah's current supply-constrained market, the Company has limited leverage to accomplish these goals. [redacted]

[3] *In the Matter of PacifiCorp d/b/a Pacific Power, 2024 Transition Adjustment Mechanism*, Exhibit PAC/500, Owen/15 (April 3, 2023).

[redacted]

**Q. How are PacifiCorp's coal facilities impacted by the coal supply constraints in Utah, and how has that been reflected in coal volumes for the 2025 TAM?**

A. Since 2022, both Hunter and Huntington plants have not received their contracted coal volumes due to the various reasons discussed in my testimony. These coal supply shortages along with market instability are expected to remain in 2024 and 2025. Specifically in 2024 and 2025, the Company forecasted the Hunter/Bronco CSA [redacted].[4] Confidential Table 1 provides a breakdown of the Hunter/Bronco CSA contractual tons versus the actual/forecast delivered tons, from 2023 to 2025:[5]

**Confidential Table 1: Contractual Tons vs. Actual/Forecast Delivered Tons**

| Hunter/Bronco CSA Third Amendment Contractual Tons vs. Actual/Forecast Delivered Tons | | |
|---|---|---|
| **Year** | **Contractual Tons** | **Delivered Tons (Actual/Forecast)** |
| 2023 | [redacted] | [redacted] |
| 2024 | [redacted] | [redacted] |
| 2025 | [redacted] | [redacted] |

*The contractual tons and actuals/forecast delivered tons are 100% Hunter Plant.

Additionally, the Company forecasted coal delivered at the Huntington plant under the Huntington/Wolverine CSA for 2024 [redacted]. Confidential Table 2

[4] *In the Matter of PacifiCorp d/b/a Pacific Power, 2024 Transition Adjustment Mechanism*, Exhibit PAC/500, Owen/9, 12, and 19 (July 24, 2023).

[5] The 2025 TAM Direct values in the tables throughout testimony are rounded for display purposes, but the underlying calculations for variances and totals are not based on the rounded display values.

provides a comparison of the Huntington/Wolverine CSA and the Hunter/Wolverine CSA contractual tons versus the actual/forecast delivered tons, from 2023 to 2025:

**Confidential Table 2: Contractual Tons vs. Actual/Forecast Delivered Tons**

| | Huntington/Wolverine CSA | | Hunter/Wolverine CSA | |
|---|---|---|---|---|
| Year | Contractual Tons (Range) | Delivered Tons (Actual/Forecast) | Contractual Tons (Range) | Delivered Tons (Actual/Forecast) |
| 2023 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2024 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2025 | [redacted] | [redacted] | [redacted] | [redacted] |

*The contractual tons and actuals/forecast delivered tons are 100% Hunter Plant.

Due to these shortfalls, PacifiCorp has adjusted its forecasts for coal received and consumed at Hunter and Huntington plants in the 2025 TAM. Accordingly, the forecast volumes of consumed coal in 2025 do not match the contracted volumes for coal in the CSAs for the calendar year 2025. Furthermore, to ensure targeted coal inventory balances are available for reliability purposes, received and consumed coal quantities at the Utah plants are balanced in the 2025 TAM and stockpiled inventory remains mostly flat.

**Q. How has the increase in market coal prices impacted the 2025 TAM estimated fuel costs?**

A. Similar to the 2024 TAM, the total coal fuel expense is estimated to decrease in the 2025 TAM, but coal prices on a per-ton basis increase at some plants. Historically, the Company's prudent coal contracting practices have largely shielded the Company and its customers from significant, short-term coal price increases. Currently, due to the increased demand for coal in both foreign and domestic markets, coal suppliers have increased opportunities for coal sales. Additionally, the mining, economic and geologic issues have caused multiple force majeure claims from PacifiCorp coal suppliers in 2022 and 2023 which has contributed to the limited volume of coal available for PacifiCorp in 2024 and 2025. Nevertheless, PacifiCorp took reasonable and prudent steps to overcome these issues by including fixed pricing provisions in its CSAs that do not escalate with general inflation. As a result, the impact of the increased coal pricing is largely contained to the circumstances in which the Company was forced to respond to suppliers force majeure claims. Specifically, the increased market prices are impacting 2025 pricing at the Wolverine, Gentry, and Bronco mines which serve the Hunter plant.

## IV. THIRD-PARTY COAL CONTRACTS

**Q. Has PacifiCorp entered into any new CSAs since it filed reply testimony in the 2024 TAM?**

A. No. PacifiCorp has not executed any CSAs or CSA amendments since the 2024 TAM Reply Update that impact coal deliveries in 2025.[6] However, in response to continuing and increasing risk of decline in available coal supply and ongoing operational challenges, the Company has been negotiating with Wolverine for several months and will be finalizing and executing amendments to its existing CSAs with Wolverine for its Hunter and Huntington plants. PacifiCorp anticipates these amendments will be finalized in the near future. As discussed in detail below, the Company is planning to provide additional information during a workshop to be held before April 1, 2024, including information relating to the Hunter/Wolverine CSA and Huntington/Wolverine CSA amendments. The Company also expects to provide a detailed analysis of these amendments in its 2025 TAM Reply Update. Table 3

[6] Consistent with the requirements for Order No. 22-389, the analysis for Hunter/Wolverine CSA dated June 7, 2023, is provided in Exhibit PAC/201.

below summarizes the CSAs that are in effect for the year 2025 as of January 2024:

**Table 3: 2025 TAM - Existing CSAs**

| Third-Party CSAs In Effect for 2025 TAM | | |
|---|---|---|
| **Plant** | **Supplier / Mine** | **CSA End Date** |
| Craig | Trapper Mining / Trapper | Dec 2025 |
| Dave Johnston | Peabody / Caballo | Dec 2025 |
| Hayden | Peabody / Twentymile | Dec 2027 |
| Hunter | Gentry / Bear Canyon # 3 | Dec 2025 |
| Hunter | Bronco / Emery | Dec 2025 |
| Hunter | Wolverine / Various | Dec 2025 |
| Huntington | Wolverine / Various | Dec 2029 |
| Naughton | Kemmerer Operations / Kemmerer | Dec 2025 |
| Wyodak | Wyodak Resources Development | Dec 2026 |

**Q. Please discuss the change in overall third-party coal-supply costs in the 2025 TAM.**

A. PacifiCorp expects a price variance net increase for the third-party coal-supply costs of [redacted], as shown in Confidential Table 6 further below.

## V. HUNTER PLANT COAL COSTS

**Q. Please describe the change in delivered coal costs at the Hunter plant in the 2025 TAM.**

A. The price of delivered coal from Bronco Utah Operations, LLC [redacted] from [redacted] per ton in the 2024 TAM Reply Update to [redacted] per ton in the 2025 TAM Direct Filing. This [redacted] is per the pricing terms of the Hunter/Bronco CSA third amendment that terminates on December 31, 2025. However, the price of delivered coal per ton [redacted] for Wolverine from the 2024 TAM Reply Update at [redacted] per ton followed by a [redacted] in price per ton for Gentry from [redacted] per ton in the 2024 TAM Reply Update to [redacted] per ton in the 2025 TAM per the contract terms.

**Q. The Commission's 2023 TAM Order directed PacifiCorp to hold a workshop with parties within a reasonable amount of time prior to filing the 2025 TAM regarding the execution of the Hunter plant CSA.[7] Why did PacifiCorp request an extension of time for holding this workshop?**

A. PacifiCorp filed a motion on February 1, 2024, requesting the Commission modify Order No. 22-389. The Commission approved the motion on February 8, 2024.[8] In the motion, the Company requested to hold the workshop by April 1, 2024, instead of prior to filing the 2025 TAM. This modification was requested to allow PacifiCorp to provide TAM parties with the latest information regarding the Company's fueling plans for the Hunter plant in calendar year 2025.

**Q. In the Commission's 2023 TAM Order, the Commission also stated that "[w]hen a new CSA is under negotiation and thus only a forecast is incorporated in a TAM, the first-year anticipated nomination as well as estimations of the total cost forecast are necessary."[9] Has this information been provided?**

A. All CSAs the Company is presently able to forecast that it will execute in 2024 which impact the 2025 TAM are shown in Confidential Table 5 below in the "Open Positions" section. The forecasted costs of these anticipated contracts are reflected in the workpapers included with the direct filing. The pricing, volumes, and other key terms of the amendments to the Hunter/Wolverine CSA and Huntington/Wolverine CSA could not be clearly determined or estimated at the time the 2025 TAM figures

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[7] *In the Matter of PacifiCorp d/b/a Pacific Power, 2023 Transition Adjustment Mechanism*, Docket No. UE 400, Order No. 22-389 at 7 (Oct. 25, 2022).
[8] *In the Matter of PacifiCorp d/b/a Pacific Power, 2023 Transition Adjustment Mechanism*, Docket No. UE 400, Order No. 24-031 at 1–2 (Feb. 8, 2024).
[9] *In the Matter of PacifiCorp d/b/a Pacific Power, 2023 Transition Adjustment Mechanism,* Docket No. UE 400, Order No. 22-389 at 5 (Oct. 25, 2022).

were calculated for the direct filing in January 2024. Therefore, the terms of these amendments will be discussed in detail in the upcoming workshop and the pricing will be included in the Reply Update.

## VI. OVERVIEW OF PACIFICORP'S COAL SUPPLIES

**Q. How does PacifiCorp plan to meet fuel supply requirements for its coal plants in 2025?**

A. PacifiCorp employs a diversified coal supply strategy, as reflected below in Confidential Table 5. PacifiCorp will supply [redacted] percent of its 2025 coal requirements with third-party coal supplies and [redacted] percent with coal from its captive affiliate mines. Within the third-party contracts: (1) [redacted] percent of the total coal requirement will be supplied from fixed-price contracts; (2) [redacted] percent will be supplied under variable-priced contracts that increase or decrease based on changes to producer and consumer price indices; and (3) [redacted] percent of the total coal requirement will be supplied from contracts for the Jim Bridger and Dave Johnston plants to be negotiated in 2024.

**Confidential Table 5: Coal Source Deliveries**

| 2025 Company/Mine | Plant | Price Reopener | New Contract | MMBtus (000s) | (000s) | Percent |
|---|---|---|---|---|---|---|
| **Affiliate Mines** | | | | | | |
| Bridger Coal/Bridger | Jim Bridger | | | [redacted] | | |
| Trapper Mining/Trapper | Craig | | | [redacted] | | |
| Subtotal Affiliate Mines | | | | | [redacted] | 18.5% |
| **Fixed Price Contracts** | | | | | | |
| Wolverine/Various | Huntington | | | [redacted] | | |
| Bronco/Emery | Hunter | | | [redacted] | | |
| Gentry Mountain/Gentry | Hunter | | | [redacted] | | |
| Wolverine/Various | Hunter | | | [redacted] | | |
| Peabody/Twentymile | Hayden | | | [redacted] | | |
| Peabody/Caballo | Dave Johnston | | | [redacted] | | |
| Kemmerer Operations | Naughton | | | [redacted] | | |
| Subtotal Fixed Price Contracts | | | | | [redacted] | 58.6% |
| **Variable Price Contracts** | | | | | | |
| Westmoreland/Rosebud | Colstrip | | | [redacted] | | |
| Black Hills/Wyodak | Wyodak | | | [redacted] | | |
| Subtotal Variable Price Contracts | | | | | [redacted] | 12.5% |
| **Open Positions** | | | | | | |
| Unspecified PRB Mines | Dave Johnston | | | [redacted] | | |
| Unspecified PRB Mines | Jim Bridger | | | [redacted] | | |
| Total Other | | | | | [redacted] | 10.3% |
| **Total Coal Supplies** | | | | | [redacted] | 100% |

Note: Delivered MMBtus are calculated from consumption estimates provided by the generation forecast in Aurora to accommodate targeted inventory stockpiles

**Q. Has total coal fuel expense in the 2025 TAM decreased from the level reflected in PacifiCorp's 2024 TAM?**

A. Yes. Total coal fuel expense has decreased by $3.3 million in the 2025 TAM. This decrease is the result of a $27.7 million volume reduction in coal-fired generation, offset by approximately $24.4 million in higher coal prices. These variances are shown in Confidential Table 6 below.

**Confidential Table 6: Coal Fuel Variance - 2025 TAM vs. 2024 TAM**

| Plant | Contract | | | Millions ($) |
|---|---|---|---|---|
| **Price Variance** | | | | |
| Affiliate Mines | | | | |
| Jim Bridger | Bridger Coal Company | [redacted] | | |
| Craig | Trapper Mining | [redacted] | | |
| Subtotal Affiliate Mines | | | [redacted] | |
| Third-Party Contracts | | | | |
| Naughton | Kemmerer Operations | [redacted] | | |
| Wyodak | Wyodak Resources | [redacted] | | |
| Dave Johnston | Powder River Basin | [redacted] | | |
| Dave Johnston | BNSF | [redacted] | | |
| Jim Bridger | Powder River Basin | [redacted] | | |
| Hunter | Wolverine Fuels | [redacted] | | |
| Hunter | Bronco | [redacted] | | |
| Hunter | Gentry Mountain | [redacted] | | |
| Huntington | Wolverine Fuels | [redacted] | | |
| Colstrip | Westmoreland | [redacted] | | |
| Hayden | Peabody | [redacted] | | |
| Subtotal Third-party Contracts | | | [redacted] | |
| **Total Price Variance** | | | | $ 24.4 |
| **Volume Variance** | | | | |
| Jim Bridger | | [redacted] | | |
| Craig | | [redacted] | | |
| Hunter | | [redacted] | | |
| Dave Johnston | | [redacted] | | |
| Wyodak | | [redacted] | | |
| Other Plants | | [redacted] | | |
| **Total Volume Variance** | | | | $ (27.7) |
| **Total Coal Fuel Variance - Increase/(Decrease)** | | | | $ (3.3) |

**Q. Please provide an overview of the cost changes by supplier in the 2025 TAM.**

A. Confidential Tables 7 through 9 compare values from the 2025 TAM Direct Filing to the 2024 TAM Reply Filing. Confidential Table 7 shows updates to the delivered price per ton from each supplier:

**Confidential Table 7**

| Delivered Price per Ton of Coal | | | | | | |
|---|---|---|---|---|---|---|
| **Plant** | **Supplier** | **2025 TAM Direct** | **2024 TAM Reply** | **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/Various | [redacted] | [redacted] | [redacted] | [redacted] | |
| Hunter | Bronco/Emery | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Hunter | Gentry/Gentry | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Huntington | Wolverine/Various | [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 8 compares the tons of coal consumed:

**Confidential Table 8**

| Consumed Volume (tons, millions) | | | | |
|---|---|---|---|---|
| **Plant** | **2025 TAM Direct** | **2024 TAM Reply** | **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 | 11.1 | 11.9 | (0.9) | (7%) |

Confidential Table 9 details the changes to total coal fuel costs:

**Confidential Table 9**

| Fuel Cost ($,millions) | | | | |
|---|---|---|---|---|
| **Plant** | **2025 TAM Direct** | **2024 TAM Reply** | **Variance-$** | **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 | 529.9 | 533.2 | (3.3) | (1%) |

Coal fuel costs have decreased by $3.3 million, driven mainly by a reduced coal generation forecast in the 2025 TAM Aurora results.

**Q. The Commission has periodically requested a current version of the "Contract Minimum" table provided in docket UE 390 in response to ALJ Bench Request 1. Has PacifiCorp provided this updated table?**

A. Yes, this information has been provided as Confidential Exhibit PAC/202.

## VII. JIM BRIDGER FUEL SUPPLY

### A. Bridger Coal Company

**Q. Please briefly summarize the benefits for PacifiCorp customers which are associated with PacifiCorp's partial ownership of BCC.**

A. Ownership in BCC allows PacifiCorp to flex coal deliveries up or down, within certain constraints, to better align Jim Bridger plant delivered and consumed coal quantities. Mine ownership also reduces coal supply delivery risk and mitigates unfavorable impacts of unexpected coal delivery changes.

**Q. Please describe the change in BCC costs in the 2025 TAM.**

A. BCC costs in the 2025 TAM are forecast to be [redacted] higher than the 2024 TAM Reply Update. The cost for the base mine plan increased by [redacted] or [redacted] per ton, from [redacted] per ton in the 2024 TAM Reply Update to [redacted] per ton in the 2025 TAM as shown in Confidential Table 10. The 2025 TAM assumes [redacted] base tons are delivered, which is [redacted] less tons delivered than in the 2024 TAM Reply Update. In the 2025 TAM, the cost for supplemental coal decreases by [redacted] per ton, from [redacted] per ton in the 2024 TAM Reply Update to [redacted] per ton in the 2025 TAM. These cost details are included in Confidential Table 10 below.

**Confidential Table 10: Jim Bridger Plant Coal Deliveries**

| | 2025 TAM | | | 2024 TAM | | | Variance | | | Price |
|---|---|---|---|---|---|---|---|---|---|---|
| | Tons | Dollars | $ / Ton | Tons | Dollars | $ / Ton | Tons | Dollars | $ / Ton | Variance |
| Bridger Coal Deliveries | | | | | | | | | | |
| Bridger Base Mine Plan | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Supplemental Coal | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Total Bridger Coal | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Unspecified PRB Mines | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Total Jim Bridger Plant | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |

**Q. Please summarize why BCC mine costs increase by [redacted] in the 2025 TAM.**

A. The price increase is primarily due to delivering [redacted] less tons in the 2025 TAM vs the 2024 TAM Reply Update and an increase in production tax valuation.

**Q. In the stipulation approved by the Commission in the 2023 TAM, PacifiCorp is required to provide the annual BCC mine plan. Has this document been provided in the workpapers to this filing?**

A. Yes, this document is included with my confidential workpapers.

**Q. In Order No. 13-387, the Commission ordered the Company to remove certain operations and maintenance costs embedded in the costs of coal from its affiliate captive mines.[10] In this filing, does PacifiCorp adjust the price of coal from BCC consistent with this order?**

A. Yes. In the 2025 TAM the Company reduces BCC costs by approximately [redacted] to reflect removal of management overtime and 50 percent of annual incentive plan awards.

[10] *In the Matter of PacifiCorp d/b/a Pacific Power 2014 Transition Adjustment Mechanism*, Docket No. UE 264, Order No. 13-387 (Oct. 28, 2013).

**B. <u>Jim Bridger Third-Party Coal Supply</u>**

**Q. Did PacifiCorp execute a new CSA with Black Butte Coal Company since the 2024 TAM Reply Update?**

A. No, PacifiCorp did not renew its existing CSA with Black Butte. Due to shortfalls in contracted deliveries during 2023, resulting from a force majeure event at the mine, a portion of the 2023 contract coal from Black Butte will be delivered during 2024. The Company currently anticipates no coal will be purchased from Black Butte in 2025.

**Q. Does PacifiCorp anticipate signing a new CSA in 2024 for coal supply from the Powder River Basin (PRB) during 2025?**

A. Yes. The Company expects to issue a request for proposals in 2024 or 2025 for additional coal supply in 2025 for Jim Bridger beyond what BCC can supply. The amount to be purchased will be determined based upon the Company's current policy and forecast market conditions.

## VIII. OZONE TRANSPORT RULE

**Q. Has the Company included any costs in this filing due to the impacts of the United States (U.S.) Environmental Protection Agency's (EPA) interstate OTR also known as the good neighbor plan?**

A. The Company did not include OTR costs in its 2025 TAM forecast because: (1) the U.S. Tenth Circuit Court of Appeals granted petitioners', including PacifiCorp, motion to stay the EPA's final disapproval of Utah's OTR state implementation plan (SIP) on July 27, 2023; and (2) EPA proposed approval of Wyoming's OTR SIP on August 14, 2023. While timelines cannot be predicted precisely, the OTR stay for the state of Utah is still under litigation with the U.S. Tenth Circuit Court of Appeals and is expected to remain in place at least through the 2024 ozone season. For Wyoming, the EPA published its final approval of Wyoming's interstate ozone transport plan in the Federal Register on December 19, 2023. The final approval of Wyoming's plan removes cross-state ozone transport requirements from electric generating units in the state, including PacifiCorp's generating units. As a result, Wyoming is not subject to the OTR federal implementation plan.

## IX. CONCLUSION

**Q. Please summarize the benefits of PacifiCorp's coal fuel strategy.**

A. Customers have significantly benefited from PacifiCorp's prudent and diversified fueling strategy, which relies upon fixed-price contracts, index-priced contracts, and affiliate-owned mines to meet the fuel needs of its coal-fired generating plants. The overall decrease in coal fuel expense in this filing is primarily due to reduced coal volumes, as shown in Confidential Table 6 above. PacifiCorp's fixed price coal contracts have continued to benefit customers as natural gas and power prices rise. However, the demand and cost for coal has increased both nationally and globally, and PacifiCorp continues to work with its coal suppliers and mines to ensure the best risk-adjusted pricing for the benefit of our customers.

**Q. Does this conclude your direct testimony?**

A. Yes.

**REDACTED**
Docket No. UE 434
Exhibit PAC/201
Witness: James C. Owen

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**REDACTED**
Exhibit Accompanying Direct Testimony of James C. Owen

Hunter/Wolverine CSA Analysis

February 2024

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

**REDACTED**
Docket No. UE 434
Exhibit PAC/202
Witness: James C. Owen

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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**REDACTED**
Exhibit Accompanying Direct Testimony of James C. Owen

CSA Contract Minimum Table

February 2024

## Confidential: Coal Supply Agreement Contract Minimums in Tons

| Plant | Coal Mine | 2025 Contractual Minimum | 2025 TAM Forecast Deliveries | Minimum % |
|---|---|---|---|---|
| Colstrip | Rosebud | [redacted] | [redacted] | [redacted] |
| Craig | Trapper | [redacted] | [redacted] | [redacted] |
| Dave Johnston | Caballo | [redacted] | | |
| Dave Johnston Total | | [redacted] | [redacted] | [redacted] |
| Hayden | Twentymile | [redacted] | [redacted] | [redacted] |
| Hunter | Wolverine | [redacted] | | |
| Hunter | Gentry | [redacted] | | |
| Hunter | Bronco[1] | [redacted] | | |
| Hunter Total | | [redacted] | [redacted] | [redacted] |
| Huntington | Wolverine[1] | [redacted] | [redacted] | [redacted] |
| Jim Bridger | Bridger | [redacted] | | |
| Jim Bridger Total | | [redacted] | [redacted] | [redacted] |
| Naughton | Kemmerer | [redacted] | [redacted] | [redacted] |
| Wyodak | Wyodak | [redacted] | [redacted] | [redacted] |

<u>Notes</u>

1. As described in testimony, force majeure claim by supplier has impacted contractual minimum.

Forecast numbers provided are from 2025 TAM initial filing.

Docket No. UE 434
Exhibit PAC/300
Witness: Judith M. Ridenour

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

---

Direct Testimony of Judith M. Ridenour

February 2024

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**ATTACHED EXHIBITS**

## I. INTRODUCTION AND QUALIFICATIONS

**Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company).**

A. My name is Judith M. Ridenour. My business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. My current position is Specialist, Pricing and Cost of Service, in the regulation department.

**Q. Briefly describe your education and professional experience.**

A. I have a Bachelor of Arts degree in Mathematics from Reed College. I joined the Company in the regulation department in October 2000. I assumed my present responsibilities in May 2001. In my current position, I am responsible for the preparation of rate design used in retail price filings and related analyses. Since 2001, with levels of increasing responsibility, I have analyzed and implemented rate design proposals throughout the Company's six-state service territory.

## II. PURPOSE OF TESTIMONY

**Q. What is the purpose of your testimony?**

A. I present PacifiCorp's proposed rate spread, rates, and revised tariff pages for the 2025 Transition Adjustment Mechanism (TAM) to recover the Oregon-allocated forecast net power costs (NPC) and other amounts identified by Company witness Ramon J. Mitchell. I also provide a summary of the impact of the proposed rate change on customers' bills.

## III. PROPOSED RATE SPREAD AND RATE DESIGN

**Q. Please describe the Company's tariff rate schedule that collects the TAM.**

A. PacifiCorp collects the TAM through Schedule 201, Net Power Costs, Cost-Based Supply Service. Collecting the TAM through a separate rate schedule allows NPC to be more easily and accurately updated through TAM filings.

**Q. What is the test period for this TAM?**

A. In accordance with the TAM Guidelines adopted in Order No. 09-274,[1] the test period for this TAM is the test year for the concurrent general rate case, which is the forecast 12 months ending December 31, 2025.

**Q. How did the Company allocate the proposed TAM revenues to the rate schedule classes?**

A. PacifiCorp allocated proposed TAM revenues to the rate schedules based on the generation allocation factors from the concurrently filed general rate case (2025 General Rate Case). This methodology accurately allocates NPC to each customer class and ensures synchronization between the TAM and the 2025 Rate Case. The spread of the proposed NPC to the customer classes is shown in page one of Exhibit PAC/301.

**Q. Did you prepare an exhibit showing the rate spread and present and proposed Schedule 201 rates and revenues?**

A. Yes. Exhibit PAC/301, starting on page two, shows present and proposed Schedule 201 rates and revenues. As explained by Company witness Mitchell, forecast NPC is subject to updates throughout this proceeding.

[1] *In the Matter of PacifiCorp, d/b/a Pacific Power, 2009 Transition Adjustment Mechanism Schedule 200, Cost-Based Supply Service,* Docket No. UE 199, Order No. 09-274 (July 16, 2009).

**Q. Is the proposed Schedule 201 rate design consistent with the TAM Guidelines?**

A. Yes. The proposed Schedule 201 rates are designed to collect revenues from rate schedules based on the proposed rate spread described above. Additionally, the rates in PacifiCorp's proposed Schedule 201 follow the rate blocks and relationships between rate blocks as the existing Schedule 201 rates.

**Q. Please describe Exhibit PAC/302.**

A. Exhibit PAC/302 contains the proposed revised Schedule 201.

**Q. Is the Company proposing changes to its transition adjustment tariff schedules at this time?**

A. No. The Company will file changes to the transition adjustment tariffs—Schedules 294, 295, and 296—once the final TAM rates have been posted and are known. The Transition Adjustment rates will be established in November, just before the open enrollment window.

**Q. Are there other tariff changes which will be made in the compliance filing in this docket?**

A. Yes. The Company will file Schedule 293 to reflect any changes to the Company Supply Service Access Charge and Schedule 220 to reflect updated market weightings based on the final TAM results in November.

## IV. COMPARISON OF PRESENT AND PROPOSED CUSTOMER RATES

**Q. What are the overall rate effects of the changes proposed in this filing?**

A. The overall proposed effect is a rate decrease of $18.3 million or 1.0 percent, on a net basis. The rate change varies by customer type. Page one of Exhibit PAC/303 shows the estimated effect of PacifiCorp's proposed prices by delivery service schedule both excluding (base) and including (net) applicable adjustment schedules. The net rates in Columns 7 and 10 exclude effects of the Low Income Bill Payment Assistance Fund (Schedule 91), Low Income Discount Cost Recovery Adjustment (Schedule 92), the Adjustment Associated with the Pacific Northwest Electric Power Planning and Conservation Act (Schedule 98), the Public Purpose Charge (Schedule 290), and the System Benefits Charge (Schedule 291).

**Q. Did you prepare an exhibit that shows the impact on customer bills as a result of the proposed TAM rate change?**

A. Yes. Exhibit PAC/303, beginning on page two, contains monthly billing comparisons for customers at different usage levels served on each of the major delivery service schedules. Each bill impact is shown in both dollars and percentages. These bill comparisons include the effects of all adjustment schedules including the Low Income Bill Payment Assistance Fund (Schedule 91), Low Income Discount Cost Recovery Adjustment (Schedule 92), the Adjustment Associated with the Pacific Northwest Electric Power Planning and Conservation Act (Schedule 98), the Public Purpose Charge (Schedule 290), and the System Benefits Charge (Schedule 291).

**Q. What is the estimated monthly impact to an average residential customer?**

A. The estimated average monthly impact to the average residential customer using 950 kilowatt-hours per month is a bill decrease of $1.19.

**Q. Does this conclude your direct testimony?**

A. Yes.

Docket No. UE 434
Exhibit PAC/301
Witness: Judith M. Ridenour

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

---

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Proposed TAM Rate Spread and Rates

February 2024

**PACIFIC POWER**
**STATE OF OREGON**
**Functionalized Net Power Cost Revenue Requirement**
**Forecast 12 Months Ended December 31, 2025**
**Dollars in Thousands**

| | | | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | **Residential** | **General Service** | | **General Service** | | **General Service** | | **Large Power Service** | | | **Irrigation** | **Street Lgt.** |
| | | Total | | Sch 23 | | Sch 28 | | Sch 30 | | Sch 48T | | | Sch 41 | Sch 15, 51 |
| Line | Description | | (sec) | (sec) | (pri) | (sec) | (pri) | (sec) | (pri) | (sec) | (pri) | (trn) | | 53, 54 |
| 1 | Functionalized Generation Revenue Requirement from GRC | $957,412 | $388,719 | $73,497 | $116 | $128,401 | $1,307 | $77,421 | $4,677 | $34,503 | $127,306 | $106,505 | $14,164 | $795 |
| 2 | | | | | | | | | | | | | | |
| 3 | Net Power Cost Revenue Requirement | $586,148 | | | | | | | | | | | | |
| 4 | Net Power Cost Collection for Schedules not included in COS Study* | $1,259 | | | | | | | | | | | | |
| 5 | Net Power Cost for Schedules Included in COS Study | $584,889 | | | | | | | | | | | | |
| 6 | | | | | | | | | | | | | | |
| 7 | | | | | | | | | | | | | | |
| 8 | Generation Allocation Factors from GRC | 100.00% | 40.60% | 7.68% | 0.01% | 13.41% | 0.14% | 8.09% | 0.49% | 3.60% | 13.30% | 11.12% | 1.48% | 0.08% |
| 9 | | | | | | | | | | | | | | |
| 10 | | | | | | | | | | | | | | |
| 11 | **Functionalized Net Power Cost Revenue Requirement- (Target)** | **$584,889** | **$237,471** | **$44,900** | **$71** | **$78,441** | **$798** | **$47,297** | **$2,857** | **$21,078** | **$77,772** | **$65,065** | **$8,653** | **$486** |
| 12 | Other Generation Revenue Requirement - (Target) | $372,523 | $151,248 | $28,597 | $45 | $49,960 | $509 | $30,124 | $1,820 | $13,425 | $49,534 | $41,441 | $5,511 | $310 |
| 13 | Sum | $957,412 | $388,719 | $73,497 | $116 | $128,401 | $1,307 | $77,421 | $4,677 | $34,503 | $127,306 | $106,505 | $14,164 | $795 |

*Revenues by rate schedule as follow:

| | |
|---|---|
| Schedule 47 Primary | $1,191 |
| Schedule 47 Transmission | $205 |
| Employee Discount | ($137) |
| Total not in study | $1,259 |

**PACIFIC POWER**
**STATE OF OREGON**
**TAM Schedule 201 Present and Proposed Rates and Revenues**

**Forecast 12 Months Ended December 31, 2025**

| Rate Schedule | Forecast Energy | Present Schedule 201 Rates | | Present Schedule 201 Revenues | Proposed Schedule 201 Rates | | Proposed Schedule 201 Revenues |
|---|---|---|---|---|---|---|---|
| **Schedule 4, Residential** | | | | | | | |
| All kWh, per kWh | 5,787,620,059 | 4.227 | ¢ | $244,642,700 | 4.103 | ¢ | $237,466,051 |
| | 5,787,620,059 | | | $244,642,700 | | | $237,466,051 |
| | | | | | Change | | -$7,176,649 |
| Employee Discount | | | | | | | |
| All kWh, per kWh | 13,364,385 | 4.227 | ¢ | $564,913 | 4.103 | ¢ | $548,341 |
| | 13,364,385 | | | $564,913 | | | $548,341 |
| Discount | | | | -$141,228 | | | -$137,085 |
| | | | | | Change | | $4,143 |
| **Schedule 23, Small General Service** | | | | | | | |
| Secondary Voltage | | | | | | | |
| 1st 3,000 kWh, per kWh | 909,353,739 | 4.218 | ¢ | $38,356,541 | 4.100 | ¢ | $37,283,503 |
| All additional kWh, per kWh | 250,901,447 | 3.127 | ¢ | $7,845,688 | 3.039 | ¢ | $7,624,895 |
| | 1,160,255,186 | | | $46,202,229 | | | $44,908,398 |
| | | | | | Change | | -$1,293,831 |
| Primary Voltage | | | | | | | |
| 1st 3,000 kWh, per kWh | 1,018,579 | 4.090 | ¢ | $41,660 | 3.975 | ¢ | $40,489 |
| All additional kWh, per kWh | 858,470 | 3.033 | ¢ | $26,037 | 2.948 | ¢ | $25,308 |
| | 1,877,049 | | | $67,697 | | | $65,797 |
| | | | | | Change | | -$1,900 |
| **Schedule 28, General Service 31-200kW** | | | | | | | |
| Secondary Voltage | | | | | | | |
| All kWh, per kWh | 2,043,261,478 | 3.932 | ¢ | $80,341,041 | 3.839 | ¢ | $78,440,808 |
| | 2,043,261,478 | | | $80,341,041 | | | $78,440,808 |
| | | | | | Change | | -$1,900,233 |
| Primary Voltage | | | | | | | |
| All kWh, per kWh | 21,450,524 | 3.842 | ¢ | $824,129 | 3.722 | ¢ | $798,389 |
| | 21,450,524 | | | $824,129 | | | $798,389 |
| | | | | | Change | | -$25,740 |
| *Schedule 29 TOU Pilot, untiered, per kWh* | | 4.961 | | | *3.839* | ¢ | |
| **Schedule 30, General Service 201-999kW** | | | | | | | |
| Secondary Voltage | | | | | | | |
| All kWh, per kWh | 1,252,474,015 | 3.856 | ¢ | $48,295,398 | 3.776 | ¢ | $47,293,419 |
| | 1,252,474,015 | | | $48,295,398 | | | $47,293,419 |
| | | | | | Change | | -$1,001,979 |
| Primary Voltage | | | | | | | |
| All kWh, per kWh | 77,804,770 | 3.843 | ¢ | $2,990,037 | 3.673 | ¢ | $2,857,769 |
| | 77,804,770 | | | $2,990,037 | | | $2,857,769 |
| | | | | | Change | | -$132,268 |
| **Schedule 41, Agricultural Pumping Service** | | | | | | | |
| Secondary Voltage | | | | | | | |
| All kWh, per kWh | 234,909,530 | 3.799 | ¢ | $8,924,213 | 3.684 | ¢ | $8,654,067 |
| | 234,909,530 | | | $8,924,213 | | | $8,654,067 |
| | | | | | Change | | -$270,146 |
| Primary Voltage | | | | | | | |
| All kWh, per kWh | 0 | 3.739 | ¢ | $0 | 3.627 | ¢ | $0 |
| | 0 | | | $0 | | | $0 |
| | | | | | Change | | $0 |
| **Schedule 47, Large General Service, Partial Requirements 1,000kW and over** | | | | | | | |
| Primary Voltage | | | | | | | |
| On-Peak, per on-peak kWh | 13,354,360 | 4.500 | ¢ | $600,946 | 4.369 | ¢ | $583,452 |
| Off-Peak, per off-peak kWh | 19,596,498 | 3.195 | ¢ | $626,108 | 3.102 | ¢ | $607,883 |
| | 32,950,858 | | | $1,227,054 | | | $1,191,335 |
| | | | | | Change | | -$35,719 |
| Transmission Voltage | | | | | | | |
| On-Peak, per on-peak kWh | 2,171,379 | 4.358 | ¢ | $94,629 | 4.154 | ¢ | $90,199 |
| Off-Peak, per off-peak kWh | 3,973,113 | 3.031 | ¢ | $120,425 | 2.889 | ¢ | $114,783 |
| | 6,144,492 | | | $215,054 | | | $204,982 |
| | | | | | Change | | -$10,072 |

**PACIFIC POWER**
**STATE OF OREGON**
**TAM Schedule 201 Present and Proposed Rates and Revenues**

**Forecast 12 Months Ended December 31, 2025**

| Rate Schedule | Forecast Energy | Present Schedule 201 Rates | | Present Schedule 201 Revenues | Proposed Schedule 201 Rates | | Proposed Schedule 201 Revenues |
|---|---|---|---|---|---|---|---|
| **Schedule 48, Large General Service, 1,000kW and over** | | | | | | | |
| Secondary Voltage | | | | | | | |
| On-Peak, per on-peak kWh | 218,085,760 | 4.625 | ¢ | $10,086,466 | 4.462 | ¢ | $9,730,987 |
| Off-Peak, per off-peak kWh | 352,821,857 | 3.333 | ¢ | $11,759,552 | 3.216 | ¢ | $11,346,751 |
| | 570,907,617 | | | $21,846,018 | | | $21,077,738 |
| | | | | | Change | | -$768,280 |
| Primary Voltage | | | | | | | |
| On-Peak, per on-peak kWh | 822,791,267 | 4.500 | ¢ | $37,025,607 | 4.369 | ¢ | $35,947,750 |
| Off-Peak, per off-peak kWh | 1,348,531,701 | 3.195 | ¢ | $43,085,588 | 3.102 | ¢ | $41,831,453 |
| | 2,171,322,968 | | | $80,111,195 | | | $77,779,203 |
| | | | | | Change | | -$2,331,992 |
| Transmission Voltage | | | | | | | |
| On-Peak, per on-peak kWh | 725,013,625 | 4.358 | ¢ | $31,596,094 | 4.154 | ¢ | $30,117,066 |
| Off-Peak, per off-peak kWh | 1,209,866,325 | 3.031 | ¢ | $36,671,048 | 2.889 | ¢ | $34,953,038 |
| | 1,934,879,950 | | | $68,267,142 | | | $65,070,104 |
| | | | | | Change | | -$3,197,038 |
| **Schedule 15, Outdoor Area Lighting Service** | | | | | | | |
| Secondary Voltage | | | | | | | |
| All kWh, per kWh | 8,156,574 | *1.374* | ¢ | $111,792 | *1.110* | ¢ | $90,512 |
| | 8,156,574 | | | $111,792 | | | $90,512 |
| | | | | | Change | | -$21,279 |
| **Schedule 51, Street Lighting Service, Company-Owned System** | | | | | | | |
| Secondary Voltage | | | | | | | |
| All kWh, per kWh | 20,858,198 | *1.696* | ¢ | $353,820 | *1.370* | ¢ | $285,846 |
| | 20,858,198 | | | $353,820 | | | $285,846 |
| | | | | | Change | | -$67,974 |
| **Schedule 53, Street Lighting Service, Consumer-Owned System** | | | | | | | |
| Secondary Voltage | | | | | | | |
| All kWh, per kWh | 8,821,260 | 1.320 | ¢ | $116,441 | 1.069 | ¢ | $94,299 |
| | 8,821,260 | | | $116,441 | | | $94,299 |
| | | | | | Change | | -$22,141 |
| **Schedule 54, Recreational Field Lighting** | | | | | | | |
| Secondary Voltage | | | | | | | |
| All kWh, per kWh | 1,373,662 | 1.320 | ¢ | $18,132 | 1.069 | ¢ | $14,684 |
| | 1,373,662 | | | $18,132 | | | $14,684 |
| | | | | | Change | | -$3,448 |
| **Total before Employee Discount** | | | | **$604,554,091** | | | **$586,293,401** |
| Employee Discount | | | | -$141,228 | | | -$137,085 |
| **TOTAL** | **15,335,068,190** | | | **$604,412,863** | | | **$586,156,316** |
| | | | | | **Change** | | **-$18,256,547** |
| Schedule 47 Unscheduled kWh | 4,283,326 | | | | | | |
| Total Forecast kWH | 15,339,351,516 | | | | | | |

Docket No. UE 434
Exhibit PAC/302
Witness: Judith M. Ridenour

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Proposed Tariff Schedule

February 2024

**Available**

In all territory served by the Company in the State of Oregon.

**Applicable**

To Residential Consumers and Nonresidential Consumers who have elected to take Cost-Based Supply Service under this schedule or under Schedules 210, 211, 212, 213 or 247. This service may be taken only in conjunction with the applicable Delivery Service Schedule. Also applicable to Nonresidential Consumers who, based on the announcement date defined in OAR 860-038-275, do not elect to receive standard offer service under Schedule 220 or direct access service under the applicable tariff. In addition, applicable to some Large Nonresidential Consumers on Schedule 400 whose special contracts require prices under the Company's previously applicable Schedule 48T. For Consumers on Schedule 400 who were served on previously applicable Schedule 48T prices under their special contract, this service, in conjunction with Delivery Service Schedule 48, supersedes previous Schedule 48T.

Nonresidential Consumers who had chosen either service under Schedule 220 or who chose to receive direct access service under the applicable tariff may qualify to return to Cost-Based Supply Service under this Schedule after meeting the Returning Service Requirements and making a Returning Service Payment as specified in this Schedule.

**Monthly Billing**

The Monthly Billing shall be the Energy Charge, as specified below by Delivery Service Schedule.

| **Delivery Service Schedule No.** | | | **Delivery Voltage** Secondary | Primary | |
|---|---|---|---|---|---|
| **Transmission** | | | | | |
| 4 | All kWh, per kWh | | 4.103¢ | | (R) |
| 5 | All kWh, per kWh | | 4.103¢ | | (R) |
| 6 | Per kWh | All kWh | 4.103¢ | | (R) |
| | plus | per On-Peak kWh | 14.270¢ | | |
| | plus | per Off-Peak kWh (credit) | -3.790¢ | | |

For Schedule 6, On-Peak hours are from 5 p.m. to 9 p.m., all days. Off-Peak hours are all remaining hours.

| | | Secondary | Primary | |
|---|---|---|---|---|
| 23 | First 3,000 kWh, per kWh | 4.100¢ | 3.975¢ | (R) |
| | All additional kWh, per kWh | 3.039¢ | 2.948¢ | (R) |
| 28 | All kWh, per kWh | 3.839¢ | 3.722¢ | (R) |

(continued)

**Monthly Billing (continued)**

| **Delivery Service Schedule No.** | | **Delivery Voltage** Secondary | Primary | Transmission | |
|---|---|---|---|---|---|
| 29 | All kWh, per kWh | 3.839¢ | 3.839¢ | | (R) |
| | Plus per Off-Peak kWh (credit) | -0.739¢ | -0.739¢ | | |

For Schedule 29, Summer On-Peak hours are from 4 p.m. to 8 p.m. Monday through Friday excluding holidays in the Summer months of April through October. Non-Summer On-Peak hours are from 6 a.m. to 10 a.m. and 5 p.m. to 8 p.m. Monday through Friday excluding holidays in the Non-Summer months of November through March. Off-Peak hours are all remaining hours.

| | | Secondary | Primary | Transmission | |
|---|---|---|---|---|---|
| 30 | All kWh, per kWh | 3.776¢ | 3.673¢ | | (R) |
| 41 | All kWh, per kWh | 3.684¢ | 3.627¢ | | (R) |
| | Optional TOU Adders | | | | |
| | Plus per On-Peak kWh | 4.989¢ | 4.989¢ | | |
| | Plus per Off-Peak kWh (credit) | -0.992¢ | -0.992¢ | | |

Schedule 41 Consumers may choose to participate in one of two Time-of-Use (TOU) rate options, Option A and Option B which provide time-varying rates in the Summer months of July, August and September. Consumers may choose to participate in Option A with On-Peak hours from 2 p.m. to 6 p.m. all days in Summer or Option B with On-Peak hours from 6 p.m. to 10 p.m. all days in Summer. Off-peak hours for each Option are all other Summer hours which are not On-Peak. All other months have no time-of-use periods or rate adders.

| | | Secondary | Primary | Transmission | |
|---|---|---|---|---|---|
| 47/48 | Per kWh On-Peak | 4.462¢ | 4.369¢ | 4.154¢ | (R) |
| | Per kWh, Off-Peak | 3.216¢ | 3.102¢ | 2.889¢ | (R) |

For Schedule 47 and Schedule 48, Summer On-Peak hours are from 1 p.m. to 10 p.m. all days in the Summer months of June through September. Non-Summer On-Peak hours are from 6 a.m. to 9 a.m. and 4 p.m. to 10 p.m. in the Non-Summer months of October through May. Off-Peak hours are all remaining hours.

| 15 | **Type of Lamp** | **LED Equivalent Lumens** | **Monthly kWh** | **Rate per Lamp** | |
|---|---|---|---|---|---|
| | Level 1 | 0-5,000 | 19 | $0.81 | (R) |
| | Level 2 | 5,001-12,000 | 34 | $1.44 | (R) |
| | Level 3 | 12,001+ | 57 | $2.42 | (R) |

(continued)

**Monthly Billing (continued)**

**Delivery Service Schedule No.**

| | Type of Lamp | LED Equivalent Lumens | Monthly kWh | Rate per Lamp | |
|---|---|---|---|---|---|
| 51 | Level 1 | 0-3,500 | 8 | $0.29 | (R) |
| | Level 2 | 3,501-5,500 | 15 | $0.54 | |
| | Level 3 | 5,501-8,000 | 25 | $0.90 | |
| | Level 4 | 8,001-12,000 | 34 | $1.24 | |
| | Level 5 | 12,001-15,500 | 44 | $1.60 | |
| | Level 6 | 15,501+ | 57 | $2.07 | (R) |

| | Types of Luminaire | Nominal rating | Watts | Monthly kWh | Rate Per Luminaire | |
|---|---|---|---|---|---|---|
| 53 | High Pressure Sodium | 5,800 | 70 | 31 | $0.33 | (R) |
| | High Pressure Sodium | 9,500 | 100 | 44 | $0.47 | |
| | High Pressure Sodium | 16,000 | 150 | 64 | $0.68 | |
| | High Pressure Sodium | 22,000 | 200 | 85 | $0.91 | |
| | High Pressure Sodium | 27,500 | 250 | 115 | $1.23 | |
| | High Pressure Sodium | 50,000 | 400 | 176 | $1.88 | |
| | Metal Halide | 9,000 | 100 | 39 | $0.42 | |
| | Metal Halide | 12,000 | 175 | 68 | $0.73 | |
| | Metal Halide | 19,500 | 250 | 94 | $1.00 | |
| | Metal Halide | 32,000 | 400 | 149 | $1.59 | |
| | Metal Halide | 107,800 | 1,000 | 354 | $3.78 | |
| | Non-Listed Luminaire, per kWh | | | | 1.069¢ | (R) |

54 Per kWh 1.069¢ (R)

(continued)

Docket No. UE 434
Exhibit PAC/303
Witness: Judith M. Ridenour

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**PACIFICORP**

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Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Estimated Effect of Proposed TAM Price Change

February 2024

**TAM Price Change**

**PACIFIC POWER**
**ESTIMATED EFFECT OF PROPOSED PRICE CHANGE**
**ON REVENUES FROM ELECTRIC SALES TO ULTIMATE CONSUMERS**
**DISTRIBUTED BY RATE SCHEDULES IN OREGON**
**FORECAST 12 MONTHS ENDED DECEMBER 31, 2025**

| | | | | | Present Revenues ($000) | | | Proposed Revenues ($000) | | | Change | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | Base Rates | | Net Rates | | |
| Line No. | Description | Sch No. | No. of Cust | MWh | Base Rates | Adders[1] | Net Rates | Base Rates | Adders[1] | Net Rates | ($000) | %[2] | ($000) | %[2] | Line No. |
| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) | (13) | (14) | |
| | | | | | | | (5) + (6) | | | (8) + (9) | (8) - (5) | (11)/(5) | (10) - (7) | (13)/(7) | |
| | **Residential** | | | | | | | | | | | | | | |
| 1 | Residential | 4 | 513,581 | 5,787,620 | $786,075 | $45,954 | $832,029 | $778,899 | $45,954 | $824,852 | ($7,177) | -0.9% | ($7,177) | -0.9% | 1 |
| 2 | **Total Residential** | | 513,581 | 5,787,620 | $786,075 | $45,954 | $832,029 | $778,899 | $45,954 | $824,852 | ($7,177) | -0.9% | ($7,177) | -0.9% | 2 |
| | **Commercial & Industrial** | | | | | | | | | | | | | | |
| 3 | Gen. Svc. < 31 kW | 23 | 86,033 | 1,162,132 | $159,887 | $10,366 | $170,253 | $158,591 | $10,366 | $168,957 | ($1,296) | -0.8% | ($1,296) | -0.8% | 3 |
| 4 | Gen. Svc. 31 - 200 kW | 28 | 10,658 | 2,064,712 | $211,334 | $25,644 | $236,978 | $209,408 | $25,644 | $235,052 | ($1,926) | -0.9% | ($1,926) | -0.8% | 4 |
| 5 | Gen. Svc. 201 - 999 kW | 30 | 847 | 1,330,279 | $118,973 | $14,740 | $133,713 | $117,839 | $14,740 | $132,579 | ($1,134) | -1.0% | ($1,134) | -0.9% | 5 |
| 6 | Large General Service >= 1,000 kW | 48 | 177 | 4,677,111 | $357,556 | $19,276 | $376,831 | $351,258 | $19,276 | $370,534 | ($6,297) | -1.8% | ($6,297) | -1.7% | 6 |
| 7 | Partial Req. Svc. >= 1,000 kW | 47 | 6 | 43,379 | $5,048 | $179 | $5,228 | $5,003 | $179 | $5,182 | ($46) | -1.8% | ($46) | -1.7% | 7 |
| 8 | Dist. Only Lg Gen Svc >= 1,000 kW | 848 | 1 | 0 | $1,517 | $547 | $2,064 | $1,517 | $547 | $2,064 | $0 | 0.0% | $0 | 0.0% | 8 |
| 9 | Agricultural Pumping Service | 41 | 7,884 | 234,910 | $32,687 | ($1,212) | $31,475 | $32,417 | ($1,212) | $31,205 | ($270) | -0.8% | ($270) | -0.9% | 9 |
| 10 | **Total Commercial & Industrial** | | 105,606 | 9,512,522 | $887,002 | $69,540 | $956,542 | $876,033 | $69,540 | $945,573 | ($10,969) | -1.2% | ($10,969) | -1.2% | 10 |
| | **Lighting** | | | | | | | | | | | | | | |
| 11 | Outdoor Area Lighting Service | 15 | 5,833 | 8,157 | $839 | $315 | $1,154 | $818 | $315 | $1,133 | ($21) | -2.5% | ($21) | -1.8% | 11 |
| 12 | Street Lighting Service Comp. Owned | 51 | 1,210 | 20,858 | $2,903 | $1,229 | $4,132 | $2,835 | $1,229 | $4,064 | ($68) | -2.3% | ($68) | -1.7% | 12 |
| 13 | Street Lighting Service Cust. Owned | 53 | 296 | 8,821 | $487 | $293 | $780 | $465 | $293 | $758 | ($22) | -4.6% | ($22) | -2.8% | 13 |
| 14 | Recreational Field Lighting | 54 | 98 | 1,374 | $91 | $58 | $148 | $87 | $58 | $145 | ($3) | -3.8% | ($3) | -2.3% | 14 |
| 15 | **Total Public Street Lighting** | | 7,437 | 39,210 | $4,319 | $1,896 | $6,215 | $4,204 | $1,896 | $6,100 | ($115) | -2.7% | ($115) | -1.9% | 15 |
| 16 | **Total Sales to Ultimate Consumers** | | 626,624 | 15,339,352 | $1,677,397 | $117,389 | $1,794,786 | $1,659,136 | $117,389 | $1,776,525 | ($18,261) | -1.1% | ($18,261) | -1.0% | 16 |
| 17 | Employee Discount | | *867* | *13,364* | ($445) | ($27) | ($472) | ($441) | ($27) | ($467) | $4 | | $4 | | 17 |
| 18 | Paperless Credit | | | | ($1,855) | | ($1,855) | ($1,855) | | ($1,855) | $0 | | $0 | | 18 |
| 19 | AGA Revenue | | | | $4,071 | | $4,071 | $4,071 | | $4,071 | $0 | | $0 | | 19 |
| 20 | COOC Amortization | | | | $1,769 | | $1,769 | $1,769 | | $1,769 | $0 | | $0 | | 20 |
| 21 | **Total Sales with AGA** | | 626,624 | 15,339,352 | $1,680,937 | $117,362 | $1,798,299 | $1,662,681 | $117,362 | $1,780,043 | ($18,257) | -1.1% | ($18,257) | -1.0% | 21 |

[1] Excludes effects of the low income assistance charges (Sch. 91 and Sch. 92), BPA credit (Sch. 98), Public Purpose Charge (Sch. 290) and System Benefits Charge (Sch. 291).
[2] Percentages shown for Schedules 48 and 47 reflect the combined rate change for both schedules

# Pacific Power
## TAM Monthly Billing Comparison
## Delivery Service Schedule 4 + Cost-Based Supply Service
## Residential Service - Single Family

| | Monthly Billing* | | | Percent |
|---|---|---|---|---|
| kWh | Present Price | Proposed Price | Difference | Difference |
| 100 | $25.41 | $25.28 | ($0.13) | -0.51% |
| 200 | $38.63 | $38.37 | ($0.26) | -0.67% |
| 300 | $51.84 | $51.46 | ($0.38) | -0.73% |
| 400 | $65.06 | $64.55 | ($0.51) | -0.78% |
| 500 | $78.27 | $77.64 | ($0.63) | -0.80% |
| 600 | $91.48 | $90.72 | ($0.76) | -0.83% |
| 700 | $104.70 | $103.82 | ($0.88) | -0.84% |
| 800 | $117.91 | $116.90 | ($1.01) | -0.86% |
| 900 | $131.13 | $129.99 | ($1.14) | -0.87% |
| **950** | **$137.73** | **$136.54** | **($1.19)** | **-0.86%** |
| 1,000 | $144.34 | $143.08 | ($1.26) | -0.87% |
| 1,100 | $157.55 | $156.16 | ($1.39) | -0.88% |
| 1,200 | $170.77 | $169.26 | ($1.51) | -0.88% |
| 1,300 | $183.98 | $182.34 | ($1.64) | -0.89% |
| 1,400 | $197.20 | $195.44 | ($1.76) | -0.89% |
| 1,500 | $210.41 | $208.52 | ($1.89) | -0.90% |
| 1,600 | $223.62 | $221.60 | ($2.02) | -0.90% |
| 2,000 | $276.48 | $273.96 | ($2.52) | -0.91% |
| 3,000 | $417.38 | $413.61 | ($3.77) | -0.90% |
| 4,000 | $558.28 | $553.25 | ($5.03) | -0.90% |
| 5,000 | $699.19 | $692.89 | ($6.30) | -0.90% |

* Net rate including Schedules 91, 92, 98, 290 and 291.

# Pacific Power
# TAM Monthly Billing Comparison
# Delivery Service Schedule 4 + Cost-Based Supply Service
# Residential Service - Multi-Family

| | Monthly Billing* | | | Percent |
|---|---|---|---|---|
| kWh | Present Price | Proposed Price | Difference | Difference |
| 100 | $22.36 | $22.23 | ($0.13) | -0.58% |
| 200 | $35.58 | $35.33 | ($0.25) | -0.70% |
| 300 | $48.79 | $48.41 | ($0.38) | -0.78% |
| 400 | $62.01 | $61.51 | ($0.50) | -0.81% |
| 500 | $75.22 | $74.59 | ($0.63) | -0.84% |
| 600 | $88.43 | $87.68 | ($0.75) | -0.85% |
| 700 | $101.65 | $100.77 | ($0.88) | -0.87% |
| 800 | $114.86 | $113.85 | ($1.01) | -0.88% |
| 900 | $128.08 | $126.95 | ($1.13) | -0.88% |
| 950 | $134.69 | $133.49 | ($1.20) | -0.89% |
| 1,000 | $141.29 | $140.03 | ($1.26) | -0.89% |
| 1,100 | $154.50 | $153.12 | ($1.38) | -0.89% |
| 1,200 | $167.72 | $166.21 | ($1.51) | -0.90% |
| 1,300 | $180.93 | $179.30 | ($1.63) | -0.90% |
| 1,400 | $194.15 | $192.39 | ($1.76) | -0.91% |
| 1,500 | $207.36 | $205.48 | ($1.88) | -0.91% |
| 1,600 | $220.57 | $218.56 | ($2.01) | -0.91% |
| 2,000 | $273.43 | $270.92 | ($2.51) | -0.92% |
| 3,000 | $414.34 | $410.56 | ($3.78) | -0.91% |
| 4,000 | $555.24 | $550.20 | ($5.04) | -0.91% |
| 5,000 | $696.14 | $689.85 | ($6.29) | -0.90% |

* Net rate including Schedules 91, 92, 98, 290 and 291.

# Pacific Power
# TAM Monthly Billing Comparison
# Delivery Service Schedule 23 + Cost-Based Supply Service
# General Service - Secondary Delivery Voltage

| kW Load Size | kWh | Monthly Billing* Present Price Single Phase | Present Price Three Phase | Proposed Price Single Phase | Proposed Price Three Phase | Percent Difference Single Phase | Percent Difference Three Phase |
|---|---|---|---|---|---|---|---|
| 5 | 500 | $87 | $95 | $86 | $95 | -0.69% | -0.63% |
| | 750 | $121 | $130 | $120 | $129 | -0.74% | -0.69% |
| | 1,000 | $156 | $164 | $155 | $163 | -0.77% | -0.72% |
| | 1,500 | $225 | $234 | $223 | $232 | -0.80% | -0.77% |
| 10 | 1,000 | $156 | $164 | $155 | $163 | -0.77% | -0.72% |
| | 2,000 | $294 | $303 | $292 | $300 | -0.81% | -0.79% |
| | 3,000 | $432 | $441 | $428 | $437 | -0.83% | -0.82% |
| | 4,000 | $552 | $561 | $547 | $556 | -0.81% | -0.80% |
| 20 | 4,000 | $588 | $596 | $583 | $592 | -0.76% | -0.75% |
| | 6,000 | $827 | $836 | $821 | $830 | -0.76% | -0.75% |
| | 8,000 | $1,067 | $1,075 | $1,059 | $1,067 | -0.76% | -0.75% |
| | 10,000 | $1,306 | $1,315 | $1,296 | $1,305 | -0.75% | -0.75% |
| 30 | 9,000 | $1,258 | $1,267 | $1,249 | $1,258 | -0.71% | -0.71% |
| | 12,000 | $1,617 | $1,626 | $1,606 | $1,614 | -0.72% | -0.72% |
| | 15,000 | $1,976 | $1,985 | $1,962 | $1,971 | -0.72% | -0.72% |
| | 18,000 | $2,336 | $2,344 | $2,319 | $2,327 | -0.73% | -0.72% |

* Net rate including Schedules 91, 92, 290 and 291.

# Pacific Power
# TAM Monthly Billing Comparison
# Delivery Service Schedule 23 + Cost-Based Supply Service
# General Service - Primary Delivery Voltage

| kW | | Monthly Billing* | | | | Percent | |
|---|---|---|---|---|---|---|---|
| | | Present Price | | Proposed Price | | Difference | |
| Load Size | kWh | Single Phase | Three Phase | Single Phase | Three Phase | Single Phase | Three Phase |
| 5 | 500 | $85 | $94 | $85 | $93 | -0.68% | -0.63% |
| | 750 | $119 | $128 | $118 | $127 | -0.73% | -0.68% |
| | 1,000 | $153 | $162 | $152 | $161 | -0.76% | -0.72% |
| | 1,500 | $221 | $230 | $219 | $228 | -0.79% | -0.76% |
| 10 | 1,000 | $153 | $162 | $152 | $161 | -0.76% | -0.72% |
| | 2,000 | $289 | $297 | $286 | $295 | -0.81% | -0.78% |
| | 3,000 | $424 | $433 | $421 | $429 | -0.83% | -0.81% |
| | 4,000 | $542 | $550 | $537 | $546 | -0.80% | -0.79% |
| 20 | 4,000 | $577 | $586 | $573 | $582 | -0.76% | -0.75% |
| | 6,000 | $812 | $821 | $806 | $815 | -0.75% | -0.74% |
| | 8,000 | $1,048 | $1,056 | $1,040 | $1,048 | -0.75% | -0.74% |
| | 10,000 | $1,283 | $1,291 | $1,273 | $1,282 | -0.74% | -0.74% |
| 30 | 9,000 | $1,236 | $1,245 | $1,227 | $1,236 | -0.70% | -0.70% |
| | 12,000 | $1,589 | $1,598 | $1,578 | $1,586 | -0.71% | -0.71% |
| | 15,000 | $1,942 | $1,950 | $1,928 | $1,936 | -0.71% | -0.71% |
| | 18,000 | $2,294 | $2,303 | $2,278 | $2,287 | -0.72% | -0.71% |

* Net rate including Schedules 91, 92, 290 and 291.

# Pacific Power
## TAM Monthly Billing Comparison
## Delivery Service Schedule 28 + Cost-Based Supply Service
## Large General Service - Secondary Delivery Voltage

| kW Load Size | kWh | Monthly Billing* Present Price | Monthly Billing* Proposed Price | Percent Difference |
|---|---|---|---|---|
| 15 | 3,000 | $400 | $397 | -0.71% |
| | 4,500 | $537 | $533 | -0.79% |
| | 7,500 | $810 | $803 | -0.87% |
| 31 | 6,200 | $808 | $802 | -0.72% |
| | 9,300 | $1,090 | $1,081 | -0.81% |
| | 15,500 | $1,654 | $1,640 | -0.88% |
| 40 | 8,000 | $1,037 | $1,029 | -0.73% |
| | 12,000 | $1,401 | $1,390 | -0.81% |
| | 20,000 | $2,129 | $2,110 | -0.89% |
| 60 | 12,000 | $1,547 | $1,536 | -0.73% |
| | 18,000 | $2,093 | $2,076 | -0.81% |
| | 30,000 | $3,186 | $3,158 | -0.89% |
| 80 | 16,000 | $2,051 | $2,036 | -0.74% |
| | 24,000 | $2,780 | $2,757 | -0.81% |
| | 40,000 | $4,236 | $4,199 | -0.89% |
| 100 | 20,000 | $2,556 | $2,537 | -0.74% |
| | 30,000 | $3,466 | $3,438 | -0.82% |
| | 50,000 | $5,287 | $5,240 | -0.89% |
| 200 | 40,000 | $5,053 | $5,016 | -0.75% |
| | 60,000 | $6,874 | $6,818 | -0.82% |
| | 100,000 | $10,516 | $10,421 | -0.90% |

* Net rate including Schedules 91, 92, 290 and 291.

# Pacific Power
## TAM Monthly Billing Comparison
## Delivery Service Schedule 28 + Cost-Based Supply Service
## Large General Service - Primary Delivery Voltage

| kW Load Size | kWh | Monthly Billing* Present Price | Monthly Billing* Proposed Price | Percent Difference |
|---|---|---|---|---|
| 15 | 4,500 | $498 | $493 | -1.10% |
| | 6,000 | $627 | $620 | -1.17% |
| | 7,500 | $756 | $747 | -1.21% |
| 31 | 9,300 | $1,010 | $999 | -1.12% |
| | 12,400 | $1,276 | $1,261 | -1.18% |
| | 15,500 | $1,543 | $1,524 | -1.22% |
| 40 | 12,000 | $1,298 | $1,284 | -1.13% |
| | 16,000 | $1,642 | $1,622 | -1.19% |
| | 20,000 | $1,985 | $1,961 | -1.23% |
| 60 | 18,000 | $1,939 | $1,917 | -1.13% |
| | 24,000 | $2,455 | $2,425 | -1.19% |
| | 30,000 | $2,970 | $2,933 | -1.23% |
| 80 | 24,000 | $2,575 | $2,546 | -1.14% |
| | 32,000 | $3,262 | $3,223 | -1.19% |
| | 40,000 | $3,949 | $3,900 | -1.23% |
| 100 | 30,000 | $3,211 | $3,175 | -1.14% |
| | 40,000 | $4,070 | $4,021 | -1.20% |
| | 50,000 | $4,929 | $4,868 | -1.24% |
| 200 | 60,000 | $6,371 | $6,298 | -1.15% |
| | 80,000 | $8,088 | $7,991 | -1.20% |
| | 100,000 | $9,805 | $9,684 | -1.24% |

* Net rate including Schedules 91, 92, 290 and 291.

# Pacific Power
## TAM Monthly Billing Comparison
## Delivery Service Schedule 30 + Cost-Based Supply Service
## Large General Service - Secondary Delivery Voltage

| kW | | Monthly Billing* | | Percent |
|---|---|---|---|---|
| Load Size | kWh | Present Price | Proposed Price | Difference |
| 100 | 20,000 | $3,004 | $2,988 | -0.54% |
| | 30,000 | $3,677 | $3,652 | -0.66% |
| | 50,000 | $5,022 | $4,981 | -0.81% |
| 200 | 40,000 | $5,565 | $5,533 | -0.58% |
| | 60,000 | $6,911 | $6,862 | -0.71% |
| | 100,000 | $9,601 | $9,520 | -0.85% |
| 300 | 60,000 | $8,284 | $8,235 | -0.59% |
| | 90,000 | $10,302 | $10,229 | -0.71% |
| | 150,000 | $14,338 | $14,216 | -0.85% |
| 400 | 80,000 | $10,889 | $10,824 | -0.60% |
| | 120,000 | $13,580 | $13,482 | -0.72% |
| | 200,000 | $18,961 | $18,799 | -0.86% |
| 500 | 100,000 | $13,526 | $13,445 | -0.60% |
| | 150,000 | $16,890 | $16,768 | -0.72% |
| | 250,000 | $23,617 | $23,414 | -0.86% |
| 600 | 120,000 | $16,164 | $16,066 | -0.60% |
| | 180,000 | $20,200 | $20,054 | -0.72% |
| | 300,000 | $28,272 | $28,028 | -0.86% |
| 800 | 160,000 | $21,439 | $21,309 | -0.61% |
| | 240,000 | $26,820 | $26,625 | -0.73% |
| | 400,000 | $37,583 | $37,258 | -0.86% |
| 1000 | 200,000 | $26,714 | $26,551 | -0.61% |
| | 300,000 | $33,440 | $33,197 | -0.73% |
| | 500,000 | $46,894 | $46,488 | -0.87% |

* Net rate including Schedules 91, 92, 290 and 291.

# Pacific Power
## TAM Monthly Billing Comparison
## Delivery Service Schedule 30 + Cost-Based Supply Service
## Large General Service - Primary Delivery Voltage

| kW Load Size | kWh | Monthly Billing* Present Price | Monthly Billing* Proposed Price | Percent Difference |
|---|---|---|---|---|
| 100 | 30,000 | $3,630 | $3,578 | -1.43% |
| | 40,000 | $4,298 | $4,229 | -1.61% |
| | 50,000 | $4,967 | $4,880 | -1.74% |
| 200 | 60,000 | $6,845 | $6,741 | -1.51% |
| | 80,000 | $8,181 | $8,043 | -1.69% |
| | 100,000 | $9,518 | $9,346 | -1.81% |
| 300 | 90,000 | $10,202 | $10,046 | -1.52% |
| | 120,000 | $12,207 | $12,000 | -1.70% |
| | 150,000 | $14,212 | $13,953 | -1.82% |
| 400 | 120,000 | $13,486 | $13,279 | -1.54% |
| | 160,000 | $16,159 | $15,883 | -1.71% |
| | 200,000 | $18,832 | $18,487 | -1.83% |
| 500 | 150,000 | $16,771 | $16,513 | -1.54% |
| | 200,000 | $20,113 | $19,768 | -1.72% |
| | 250,000 | $23,455 | $23,023 | -1.84% |
| 600 | 180,000 | $20,057 | $19,747 | -1.55% |
| | 240,000 | $24,067 | $23,653 | -1.72% |
| | 300,000 | $28,077 | $27,560 | -1.84% |
| 800 | 240,000 | $26,629 | $26,215 | -1.56% |
| | 320,000 | $31,976 | $31,424 | -1.73% |
| | 400,000 | $37,322 | $36,632 | -1.85% |
| 1000 | 300,000 | $33,201 | $32,683 | -1.56% |
| | 400,000 | $39,884 | $39,194 | -1.73% |
| | 500,000 | $46,567 | $45,705 | -1.85% |

* Net rate including Schedules 91, 92, 290 and 291.

# Pacific Power
## TAM Monthly Billing Comparison
## Delivery Service Schedule 41 + Cost-Based Supply Service
## Agricultural Pumping - Secondary Delivery Voltage

| | | Present Price* | | Proposed Price* | | Percent Difference | |
|---|---|---|---|---|---|---|---|
| kW Load Size | kWh | Monthly Bill | Annual Load Size Charge | Monthly Bill | Annual Load Size Charge | Monthly Bill | Annual Load Size Charge |
| Single Phase | | | | | | | |
| 10 | 2,000 | $233 | $174 | $231 | $174 | -1.00% | 0.00% |
| | 3,000 | $350 | $174 | $346 | $174 | -1.00% | 0.00% |
| | 5,000 | $583 | $174 | $577 | $174 | -1.00% | 0.00% |
| Three Phase | | | | | | | |
| 20 | 4,000 | $466 | $347 | $462 | $347 | -1.00% | 0.00% |
| | 6,000 | $700 | $347 | $693 | $347 | -1.00% | 0.00% |
| | 10,000 | $1,166 | $347 | $1,155 | $347 | -1.00% | 0.00% |
| 100 | 20,000 | $2,332 | $1,604 | $2,309 | $1,604 | -1.00% | 0.00% |
| | 30,000 | $3,499 | $1,604 | $3,464 | $1,604 | -1.00% | 0.00% |
| | 50,000 | $5,831 | $1,604 | $5,773 | $1,604 | -1.00% | 0.00% |
| 300 | 60,000 | $6,997 | $3,979 | $6,927 | $3,979 | -1.00% | 0.00% |
| | 90,000 | $10,496 | $3,979 | $10,391 | $3,979 | -1.00% | 0.00% |
| | 150,000 | $17,493 | $3,979 | $17,318 | $3,979 | -1.00% | 0.00% |

* Net rate including Schedules 91, 92, 98, 290 and 291.

# Pacific Power
## TAM Monthly Billing Comparison
## Delivery Service Schedule 41 + Cost-Based Supply Service
## Agricultural Pumping - Primary Delivery Voltage

| | | Present Price* | | Proposed Price* | | Percent Difference | |
|---|---|---|---|---|---|---|---|
| kW Load Size | kWh | Monthly Bill | Annual Load Size Charge | Monthly Bill | Annual Load Size Charge | Monthly Bill | Annual Load Size Charge |
| Single Phase | | | | | | | |
| 10 | 3,000 | $344 | $172 | $341 | $172 | -0.99% | 0.00% |
| | 4,000 | $459 | $172 | $454 | $172 | -0.99% | 0.00% |
| | 5,000 | $573 | $172 | $568 | $172 | -0.99% | 0.00% |
| Three Phase | | | | | | | |
| 20 | 6,000 | $688 | $343 | $681 | $343 | -0.99% | 0.00% |
| | 8,000 | $917 | $343 | $908 | $343 | -0.99% | 0.00% |
| | 10,000 | $1,147 | $343 | $1,135 | $343 | -0.99% | 0.00% |
| 100 | 30,000 | $3,440 | $1,573 | $3,406 | $1,573 | -0.99% | 0.00% |
| | 40,000 | $4,587 | $1,573 | $4,542 | $1,573 | -0.99% | 0.00% |
| | 50,000 | $5,734 | $1,573 | $5,677 | $1,573 | -0.99% | 0.00% |
| 300 | 90,000 | $10,321 | $3,908 | $10,219 | $3,908 | -0.99% | 0.00% |
| | 120,000 | $13,762 | $3,908 | $13,625 | $3,908 | -0.99% | 0.00% |
| | 150,000 | $17,202 | $3,908 | $17,031 | $3,908 | -0.99% | 0.00% |

* Net rate including Schedules 91, 92, 98, 290 and 291.

# Pacific Power
# TAM Monthly Billing Comparison
# Delivery Service Schedule 48 + Cost-Based Supply Service
# Large General Service - Secondary Delivery Voltage
# 1,000 kW and Over

| kW Load Size | kWh | Monthly Billing Present Price | Monthly Billing Proposed Price | Percent Difference |
|---|---|---|---|---|
| 1,000 | 300,000 | $32,764 | $32,354 | -1.25% |
| | 500,000 | $47,055 | $46,372 | -1.45% |
| | 700,000 | $61,346 | $60,390 | -1.56% |
| 2,000 | 600,000 | $64,939 | $64,120 | -1.26% |
| | 1,000,000 | $91,729 | $90,334 | -1.52% |
| | 1,400,000 | $119,203 | $117,249 | -1.64% |
| 6,000 | 1,800,000 | $180,421 | $177,909 | -1.39% |
| | 3,000,000 | $262,842 | $258,655 | -1.59% |
| | 4,200,000 | $345,263 | $339,402 | -1.70% |
| 12,000 | 3,600,000 | $358,683 | $353,659 | -1.40% |
| | 6,000,000 | $523,145 | $514,772 | -1.60% |
| | 8,400,000 | $687,075 | $675,352 | -1.71% |

Notes:

| | |
|---|---|
| On-Peak kWh | 38.20% |
| Off-Peak kWh | 61.80% |

* Net rate including Schedules 91, 92, 290 and 291. Restricted Sch 291 applied to levels over 730,000 kWh.

# Pacific Power
## TAM Monthly Billing Comparison
## Delivery Service Schedule 48 + Cost-Based Supply Service
## Large General Service - Primary Delivery Voltage
## 1,000 kW and Over

| kW Load Size | kWh | Monthly Billing Present Price | Monthly Billing Proposed Price | Percent Difference |
|---|---|---|---|---|
| 1,000 | 300,000 | $31,058 | $30,731 | -1.05% |
| | 500,000 | $45,050 | $44,505 | -1.21% |
| | 700,000 | $59,043 | $58,280 | -1.29% |
| 2,000 | 600,000 | $61,537 | $60,883 | -1.06% |
| | 1,000,000 | $87,643 | $86,529 | -1.27% |
| | 1,400,000 | $114,507 | $112,947 | -1.36% |
| 6,000 | 1,800,000 | $176,526 | $174,521 | -1.14% |
| | 3,000,000 | $257,117 | $253,775 | -1.30% |
| | 4,200,000 | $337,708 | $333,030 | -1.39% |
| 12,000 | 3,600,000 | $350,923 | $346,913 | -1.14% |
| | 6,000,000 | $511,725 | $505,043 | -1.31% |
| | 8,400,000 | $671,996 | $662,640 | -1.39% |

Notes:

| | |
|---|---|
| On-Peak kWh | 37.89% |
| Off-Peak kWh | 62.11% |

* Net rate including Schedules 91, 92, 290 and 291. Restricted Sch 291 applied to levels over 730,000 kWh.

# Pacific Power
## TAM Monthly Billing Comparison
## Delivery Service Schedule 48 + Cost-Based Supply Service
## Large General Service - Transmission Delivery Voltage
## 1,000 kW and Over

| kW Load Size | kWh | Monthly Billing Present Price | Monthly Billing Proposed Price | Percent Difference |
|---|---|---|---|---|
| 1,000 | 500,000 | $42,973 | $42,135 | -1.95% |
| | 700,000 | $56,452 | $55,278 | -2.08% |
| 2,000 | 1,000,000 | $83,253 | $81,540 | -2.06% |
| | 1,400,000 | $109,067 | $106,668 | -2.20% |
| 6,000 | 3,000,000 | $247,194 | $242,054 | -2.08% |
| | 4,200,000 | $324,634 | $317,437 | -2.22% |
| 12,000 | 6,000,000 | $491,621 | $481,340 | -2.09% |
| | 8,400,000 | $645,588 | $631,195 | -2.23% |

Notes:

| | |
|---|---|
| On-Peak kWh | 37.47% |
| Off-Peak kWh | 62.53% |

* Net rate including Schedules 91, 92, 290 and 291. Restricted Sch 291 applied to levels over 730,000 kWh.