Oregon

Tina Kotek, Governor

Public Utility Commission
201 High St SE Suite 100
Salem, OR 97301-3398
Mailing Address: PO Box 1088
Salem, OR 97308-1088
503-373-7394

June 23, 2023

Via Electronic Filing

OREGON PUBLIC UTILITY COMMISSION ATTENTION: FILING CENTER
PO BOX: 1088
SALEM OR 97308-1088

RE: Docket No. UE 420 – In the Matter of PACIFICORP, dba PACIFIC POWER, 2024 Transition Adjustment Mechanism.

Attached for filing are the following exhibits, certificate of service and service list:

Staff Opening Testimony:

Exhibit 100-102 Kim with Confidential
Exhibit 200-203 Jent with Confidential
Exhibit 300-304 Dlouhy with Confidential
Exhibit 400-402 Anderson with Confidential and Highly-Confidential
Exhibit 500-502 Bolton with Confidential
Exhibit 600-601 Chipanera with Confidential

Both confidential and non-confidential electronic exhibits are included with this filing.

Confidential workpapers are also included.

/ Kay Barnes
Oregon Public Utility Commission
(971) 375-5079
Kay.barnes@puc.oregon.gov

CASE: UE 420
WITNESS: ANNA KIM

PUBLIC UTILITY COMMISSION
OF
OREGON

REDACTED STAFF EXHIBIT 100

Opening Testimony

June 23, 2023

Q. Please state your name, occupation, and business address.

A. My name is Anna Kim. I am the Energy Costs Section Manager employed in the Rates, Safety and Utility Performance (RSUP) Program of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/101.

Q. What is the purpose of your testimony?

A. My testimony is presented in three sections. First, as Staff's summary witness, I will present an overview of PacifiCorp's 2024 Transition Adjustment Mechanism (TAM) filing, putting the forecasted costs into perspective by contrasting them with previous year's actuals. In this section, I also present a summary of the dollar effect of Staff's adjustments and overview of the issues reviewed by Staff in this filing, including detail of where each topic is discussed, and I present a summary of the adjustments and recommendations made by Staff.

The second section of my testimony addresses PacifiCorp's compliance with the TAM guidelines and Order No. 22-389 resulting from the most recent 2023 TAM. The third section addresses proposed changes to hydroelectric generation.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared the following Staff Exhibits:

- Staff/101: Witness Qualifications Statement.

- Staff/102: PacifiCorp's responses to relevant Staff DRs.

Q. How is your testimony organized?

A. My testimony is organized as follows:

OVERVIEW OF 2024 TAM FILING

Q. Please summarize PacifiCorp's 2024 TAM filing.

A. The Company has forecasted 2024 Net Power Costs (NPC) of $2.642 billion, representing an increase of approximately $665 million system-wide, or a $164 million increase on an Oregon-only basis. This represents a $255 million increase in NPC compared with the final 2023 forecast, a $7.8 million increase in the Production Tax Credit (PTC), and an anticipated $84 million increase in collections based on increased load.[1]

Q. What are major drivers for the forecasted $665 million increase in system-wide NPC?

A. In direct testimony, PacifiCorp explains that this significant increase in forecasted costs is driven by multiple factors, including increased gas, coal, and power market prices, and incorporating costs of the Washington Cap and Invest program and federal Ozone Transport Rule.[2]

Q. How have individual cost categories changed since last year's filing?

A. PacifiCorp's initial filing forecasts a 24 percent ($137 million) reduction in revenue from power sales. Gas expenses are forecasted to double ($427.8 million), while coal expenses decrease by fourteen percent ($87.9 million). Wheeling costs increase by seven percent. Total purchased power costs are forecasted to increase by 12 percent

---

1 PAC/100, Mitchell/6.
2 PAC/100, Mitchell/7.

($159.2 million). Year-on-year changes between expenses and revenues forecasted in the 2024 TAM and 2023 TAM are further summarized in Figure 1.

CONF FIGURE 1. 2024 TAM VS. 2023 TAM VS. 2022 PCAM[3]

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. What is the effect of the forecasted system-wide NPC increase on an Oregon basis?

A. Oregon-allocated NPC are forecasted to total $674 million. This represents a 57.9 percent increase on the 2023 NPC forecast.[4]

Q. Please provide an overview of Staff's testimony.

[3] Staff/102, Kim, PAC Response to Staff DRs 1-2 and associated Confidential Attachments.
[4] PAC/101, Mitchell/1.

A. Staff's review has focused on the main expenses forecasted by the Company, and on the modeling changes the Company has proposed. Staff has also reviewed the Company's compliance with recent TAM Orders.

Q. What is the effect of Staff's proposed adjustments on rates?

A. Staff's proposed adjustments total **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** on a total-company basis, or **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** on an Oregon-allocated basis, as demonstrated in Figure 2 below.

CONF FIGURE 1. EFFECT OF STAFF ADJUSTMENTS ON FORECASTED NPC

[BEGIN CONFIDENTIAL]

Staff Issue #	System-Wide	System-Wide
Staff/200, Jent Issue 1	($20,009,226)	($5,216,405)
Staff/300, Dlouhy Issue 1	($19,800,000)	($5,690,000)
Staff/400, Anderson Issue 3	[redacted]	[redacted]
Staff/600, Chipanera Issue 1	($3,499,716)	($1,004,468)
Total Adjustments	[redacted]	[redacted]
Forecasted 2024 NPC	$2,361,354,814	$674,321,365
Forecasted 2024 NPC including Staff adjustments	[redacted]	[redacted]
Final 2023 NPC	$1,697,160,684	$426,985,855

[END CONFIDENTIAL]

Including Staff's adjustments in the forecast of NPC would lead to an overall increase in Oregon NPC of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** compared with 2023 NPC, representing a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** percent increase in NPC for 2024, in contrast to the $674 million NPC, or 57.9 percent increase in NPC proposed for Oregon by PacifiCorp.

Q. What issues are addressed in Staff's testimony?

A. In Staff/100, I provide an overview of the filing, a review of the Company's compliance with the TAM guidelines and Commission Orders, and hydroelectric generation changes.

In Staff/200, witness Julie Jent addresses the standard updates to the Company's TAM filing, benchmarking, and the Company's DA/RT adder.

In Staff/300, witness Curtis Dlouhy addresses the Company's modelling of market caps, EIM benefits, trapped services, and modeling improvements.

In Staff/400, witness Rose Anderson addresses Washington Cap and Invest program, coal contracts, and Jim Bridger natural gas conversion.

In Staff/500, witness Madison Bolton addresses the Company's forecast of costs for purchases from Qualifying Facilities (QF) and the calculation of Direct Access rates.

In Staff/600, witness Itayi Chipanera addresses Production Tax Credits (PTC) and wind net power cost benefits.

Q. Has Staff proposed any adjustments?

A. Yes. Staff's adjustments are summarized in Confidential Figure 2 above, and as follows:

1. A reduction in Oregon-allocated power cost of $5.21 million as a placeholder to reject the change to the DA/RT as detailed in Staff/200, Issue 1.

2. A reduction in Oregon-allocated power costs of $5.69 million to represent the "third quartile of averages" approach to market caps rather than the "average of averages" as detailed in Staff/300, Issue 1.
3. A downward adjustment of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** representing allocation of a portion of the benefits of the Washington Cap and Invest credits allocated to Oregon customers as detailed in Staff/400, Issue 3.
4. An increase the Company's Oregon allocated PTC credit by $1.3 million based on Staff's adjustment to the Company's forecasted wind generation during the test period as discussed in Staff/600, Issue 1.

Additionally, Staff proposes the following:

5. Coal contract management adjustment – an adjustment if it turns out that the Company did not take reasonable steps to add flexibility to existing and new coal contracts in response to Utah coal supply issues as discussed in Staff/400, Issue 1.
6. Thermal generation alternatives modeling adjustment – an adjustment if it turns out that other alternatives should have been more available to the Aurora model to reduce capacity factors at certain thermal units as discussed in Staff/400, Issue 3.

Q. Has Staff made any other recommendations?

A. Yes. In summary, Staff recommends that the Commission require PacifiCorp to:

1. Resume using dollars rather than a percentage for the DA/RT, as described in Staff/200, Issue 1.
2. Address DA/RT modeling holistically in conjunction with market caps as described in Staff/300, Issue 1.
3. Return to using the "third quartile of averages" method to forecast market caps rather than the Company's proposed "average of averages" approach, as described in Staff/300, Issue 1.
4. Hold workshops in future TAM filings to discuss DA/RT adjustments made to the AURORA model, as described in Staff/200, Issue 1.
5. Allocate a portion of the benefits of Washington Cap and Invest credits to Oregon customers, as detailed in Staff/400, Issue 3.

Q. Are further updates expected in the docket?

A. Yes. In accordance with the TAM Guidelines, PacifiCorp will include the most recent official forward price curve (OFPC) in its reply testimony, which is due to be published on July 24, 2023. The Company will provide two further updates to the OFPC in November.

ISSUE 1. COMPLIANCE WITH PRIOR TAM ORDERS AND TAM GUIDELINES

Q. What were the compliance implications of the 2023 TAM Order?

A. In Order No. 22-389, the Commission included several provisions that required further action by the Company. Under Order No. 22-389, PacifiCorp is required to do the following:

- Provide projections for its Hunter contract, including an analysis of the appropriate minimum take and overall thermal fleet usage in multiple scenarios; [5] and,
- Explain how dispatch of generation resources is changing in response to the changing utilization of coal plants and provide unit-by-unit data on projected coal delivery. [6]

By stipulation in Order No. 22-389, PacifiCorp is also required to:

- Produce a benchmarking study for the 2024 TAM proceeding and the 2025 TAM proceeding;[7]
- Update the Jim Bridger Long-Term Fuel Supply Plan for the 2023 IRP with three scenarios and provide an updated Jim Bridger Long-Term Fuel Supply Plan for the 2023 IRP;[8]
- Provide a copy of the updated annual Bridger Coal Company mine plan along with any alternatives that were also evaluated for PacifiCorp;[9] and

---

5 Order No. 22-389, p. 6-7.
6 Order No. 22-389, p. 7.
7 Order No. 22-389, Attachment A, p. 6.
8 Order No. 21-379, Attachment A, p. 7.
9 Order No. 22-389, Attachment A, p. 6.

- File the 2024 TAM.[10]

Q. Did the Company provide projections for its Hunter contract as described in Order No. 22-389?

A. Yes. The Company provided this information in Confidential Exhibit PAC/200, which includes highly confidential information. Staff discusses this topic in Staff/400, Issue 1.

Q. Did the Company describe how dispatch of generation resources is changing in response to the changing utilization of coal plants and provide data as requested in Order No. 22-389?

A. Yes. The Company provided this information in Confidential Exhibit PAC/200. Staff discusses this topic in Staff/400, Issue 1.

Q. Did the Company produced a benchmarking study for the 2024 TAM proceeding?

A. Yes. The Company provided this information in Confidential Exhibit PAC/106. Staff discusses this topic in Staff/200, Issue 4.

Q. Has the Company updated and provided the Jim Bridger Long-Term Fuel Supply Plan for the 2023 IRP along with updates as discussed in Order No. 22-379?

A. Yes. This data was provided with the Company's 15-day work papers. Staff discusses this topic in Staff/400, Issue 2.

---

[10] Order No. 22-389, p. 9.

Q. Has the Company provided a copy of the updated annual Bridger Coal Company mine plan along with any alternatives that were also evaluated for PacifiCorp?

A. Yes. This data was provided with the Company's 15-day work papers. Staff discusses this topic in Staff/400, Issue 1.

Q. Did the Company file the 2024 TAM in compliance with Order No. 22-389?

A. Yes. The Company filed the 2023 TAM on April 3, 2023.

Q. Did the Company update and file the Jim Bridger Long Term Fuel Plan document?

A. Yes. This data was provided with the Company's 15-day work papers. Staff discusses this topic in Staff/400, Issue 2.

Q. Did the Company file the 2024 TAM as directed by the Commission?

A. Yes. The Company filed the 2023 TAM on April 3, 2023.

Q. Did the Company comply with the TAM Guidelines set forth in Commission Order No. 09-274?

A. Staff has reviewed the Company's 2024 TAM filing and finds that they have thus far complied with the TAM Guidelines. Part of the guidelines dictate what the Company can and cannot update over the pendency of the TAM, and as such, Staff cannot conclude that the Company has completely satisfied all requirements.

Q. Are there additional modeling concerns discussed in Order No. 22-389 that were not stipulated that Staff will bring up?

A. Yes. The stipulation in the previous TAM allowed the case to be settled without agreement of parties on the methodology for market caps, regulating reserves, planned maintenance, and the day-ahead/real-time price adder. In this TAM. However, the Company included many of these changes without providing supporting evidence. In some cases, the Company simply referred to its UE 400 testimony to support its proposal in this docket, which made it seem as though it had been agreed upon and that evidence did not need to be reiterated in this docket.

Q. What is the relationship between market caps and the day ahead/real-time price adder?

A. Market caps and day ahead/real-time price adders are both adjustments to wholesale power purchases in the model. Market caps will be discussed in Staff/300 and DA/RT in Staff/200.

Q. Did the Company provide a step log in compliance with TAM guidelines?

A. No, not really. In Exhibit PAC/104, the Company provides impacts associated with specific changes. These are not “steps” in the sense that the changes do not stack on top of each other as in separate distinct increases in power costs but are entirely separate. This information is mis-named and does not provide the same kind of transparency as an actual step log.

ISSUE 2. HYDROELECTRIC GENERATION

Q. How is the hydroelectric generation forecast changing in the 2024 TAM?

A. PacifiCorp forecasts hydroelectric generation decreasing by 569,000 MWh between the 2024 TAM and the 2023 TAM.[11]

Q. What is the impact of the change to the hydroelectric forecast on net power costs?

A. This change results in an anticipated increase of $53 million company-wide and $15 million for Oregon due to increased market purchases to replace this generation.[12]

Q. Please describe why the hydroelectric generation forecast is changing.

A. In direct testimony, the Company described the removal of four company-operated projects on the Klamath River, which totals 180 MW of capacity. These hydroelectric generators are expected to go offline by the end of 2023.[13]

Q. Do you recommend changes be made to the hydroelectric forecast for the 2024 TAM?

A. Not at this time. Staff wishes to review testimony from other parties and further review the Company's plans to replace this generation.

Q. Does this conclude your testimony?

A. Yes.

---

[11] PAC/100, Mitchell/23.
[12] PAC/100, Mitchell/23.
[13] PAC/100, Mitchell/23.

CASE: UE 420
WITNESS: Anna Kim

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualifications Statement

June 23, 2023

WITNESS QUALIFICATION STATEMENT

NAME:	Anna Kim
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Energy Costs Section Manager Rates, Safety and Utility Performance Program
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	Master of Science, Economics Portland State University, Portland, OR Master of Environmental Studies, The Evergreen State College, Olympia, WA Bachelor of Arts, Economics University of California, Berkeley, CA
EXPERIENCE:	I have been employed by the Oregon Public Utility Commission (OPUC) since July 2018 originally in the Energy Resources and Planning Division principally as the Staff liaison with the Energy Trust and then as Energy Costs Section Manager starting May 2023. My responsibilities include analyzing, working with Staff assigned, leading and managing energy cost dockets. Prior to working for the Commission, I worked for Seattle City Light as a power resource planner developing integrated resource plans. I also worked for five years as an evaluation consultant which involved evaluating energy efficiency and demand response pilots and programs and market research.

CASE: UE 420
WITNESS: Anna Kim

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF CONFIDENTIAL EXHIBIT 102

Exhibits in Support
Of Opening Testimony

June 23, 2023

OPUC Data Request 1

General - Regarding total Net Variable Power Cost:

(a) Please provide the total forecasted Net Variable Power Cost included in rates for each year from 2014 through 2023.

(b) Please provide the total Net Variable Power Costs incurred in each year from 2014 through 2023, to date.

(c) Please provide the requested information in electronic workbook format with all cells and formulas intact. Please provide the requested information both on a system and Oregon only basis.

This is an ongoing request. Please update the Company's response to subpart (b) following each of the Company's update filings and provide updated data in response to subpart (c) as it becomes available.

Response to OPUC Data Request 1

PacifiCorp objects to this request as overly broad, unduly burdensome and not reasonably calculated to lead to the discovery of admissible evidence. Without waiving the foregoing objection, PacifiCorp responds as follows:

The Company assumes that the reference to "Net Variable Power Costs" refers to net power costs (NPC); the Company assumes that the terms net variable power costs (NVPC) and NPC are interchangeable.

In addition, the Company interprets this request for "included in rates for each year from 2014 through 2023" to be asking for information from PacifiCorp's transition adjustment mechanism (TAM) proceedings from the following dockets:

Docket UE-264 (forecast year 2014 TAM)
Docket UE-287 (forecast year 2015 TAM)
Docket UE-296 (forecast year 2016 TAM)
Docket UE-307 (forecast year 2017 TAM)
Docket UE-323 (forecast year 2018 TAM)
Docket UE-339 (forecast year 2019 TAM)
Docket UE-356 (forecast year 2020 TAM)
Docket UE-375 (forecast year 2021 TAM)
Docket UE-390 (forecast year 2022 TAM)
Docket UE-400 (forecast year 2023 TAM)

Based on the foregoing assumption and interpretation, the Company responds as follows:

(a) Please refer to Confidential Attachment OPUC 1-1 which provides forecasted net power costs (NPC) included in rates for each year from 2014 through 2023.

(b) Please refer to Attachment OPUC 1-2 which provides copies of the Company's actual NPC (total company) for calendar years 2014 through 2022. Please refer to Confidential Attachment OPUC 1-3 which provides copies of the associated actual NPC (total company) mapping files for calendar year 2014 through 2022.

Please refer to Confidential Attachment OPUC 1-4 which provides a copy of the Company's actual NPC (total company) for calendar year 2023 year-to-date, (January 2023 and February 2023), together with the associated actual NPC (total company) mapping file. Note: actual NPC for calendar year 2023 are preliminary, subject to change.

Please refer to Confidential Attachment OPUC 1-5 which provides copies of the Company's Oregon power cost adjustment mechanism (PCAM) calculations from calendar year 2014 through 2021. Note 1: 2022 data will not be available until after the Company's PCAM filing is submitted to the Public Utility Commission of Oregon (OPUC) on May 15, 2023. The Company will supplement this response with 2022 data shortly thereafter. Note 2: 2023 data will not be available until after the Company's PCAM filing is submitted to the OPUC in mid-May 2024.

(c) Where relevant and applicable, please refer to the Company's responses to subpart (a) and (b) above.

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.

PAC Response to DR 1 Attachment is only available in electronic format.

UE 420 / PacifiCorp
May 10, 2023
OPUC Data Request 2

OPUC Data Request 2

General - Regarding the Company's forecasts and actuals:

(a) Please provide a breakdown of the power resources included in the Company's final Net Variable Power Cost forecast for each year from 2014 through 2024. Please provide:

i. Total volume of power forecasted from each resource type (e.g. wind, market purchases, solar natural gas)
ii. Total cost in US dollars of each resource type.
iii. Average per MWh cost in US dollars for each resource type.

(b) Please provide a breakdown of the power resources included in the Company's 2024 Net Variable Power Cost forecast. Please provide:

i. Total volume of power forecasted from each resource type.
ii. Total cost in US dollars of each resource type.
iii. Average per MWh cost in US dollars for each resource type.
iv. If the above information is already provided, detail which work paper this can be found in.

(c) Please provide a breakdown of the actual power resources used by the Company for each year from 2014 through 2023. Please provide:

i. Total volume of power produced by each resource type.
ii. Total cost in US dollars of each resource type.
iii. Average per MWh cost in US dollars for each resource type.

Please provide the requested details for each resource type separately. Provide QF resource types separately to non-QF resources of the same type. For power purchases and sales, provide long-term power contracts (>1 year) separately to short-term firm power purchases and sales and system balancing purchases and sales.

This is an ongoing request. Please update this response following each of the Company's update filings and provide updates to requested data for 2023 as it becomes available.

Response to OPUC Data Request 2

PacifiCorp objects to this request as overly broad, unduly burdensome and not reasonably calculated to lead to the discovery of admissible evidence. Without waiving the foregoing objection, PacifiCorp responds as follows:

The Company assumes that the reference to "Net Variable Power Costs" refers to net power costs (NPC); the Company assumes that the terms net variable power costs (NVPC) and NPC are interchangeable.

In addition, the Company interprets this request for "included in the Company's final Net Variable Power Cost forecast for each year from 2014 through 2024" to be asking for information from PacifiCorp's transition adjustment mechanism (TAM) proceedings from the following dockets:

Docket UE-264 (forecast year 2014 TAM)
Docket UE-287 (forecast year 2015 TAM)
Docket UE-296 (forecast year 2016 TAM)
Docket UE-307 (forecast year 2017 TAM)
Docket UE-323 (forecast year 2018 TAM)
Docket UE-339 (forecast year 2019 TAM)
Docket UE-356 (forecast year 2020 TAM)
Docket UE-375 (forecast year 2021 TAM)
Docket UE-390 (forecast year 2022 TAM)
Docket UE-400 (forecast year 2023 TAM)
Docket UE-420 (forecast year 2024 TAM) – this proceeding

Based on the foregoing assumption and interpretation, the Company responds as follows:

(a) Please refer to the Confidential Attachment OPUC 2 which provides the final net power costs (NPC) reports from each Oregon transition adjustment mechanism (TAM) proceeding covering forecast years 2014 through 2023 (Docket UE-264 through Docket UE-400). The requested information is provided in the Company's NPC reports, specifically tab "NPC" in each of the provided files (in dollars ($), megawatt-hours (MWh) and $/MWh). Note: Final NPC for the 2024 TAM are not yet available.

(b) Please refer to the concurrent confidential work papers supporting the direct testimony of Company witness, Ramon J. Mitchell, provided with the Company's response to TAM Support Set 1 (concurrent), specifically confidential folder "NPCReport", confidential file "_OR UE-420 ORTAM24_Mitchell Direct Mar 2023 CONF.xlsm", tab "NPC" (in $, MWh and $/MWh). The Company will supplement this response with additional information as it becomes available during the course of this proceeding.

(c) Please refer to the Company's response to OPUC Data Request 1 subpart (b). The actual NPC reports provide $ and MWh. $/MWh can be calculated by dividing $ by MWh.

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.

**PAC CONF Response to DR 2 CONF
Attachment is only available in electronic
format.**

CASE: UE 420
WITNESS: JULIE JENT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 200

Opening Testimony

June 23, 2023

Q. Please state your name, occupation, and business address.

A. My name is Julie Jent. I am a Senior Utility Analyst employed in the Energy Costs Section of the Rates Safety and Utility Performance (RSUP) Program of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/201.

Q. What is the purpose of your testimony?

A. I provide background and recommendations on certain issues regarding PacifiCorp's 2024 Transition Adjustment Mechanism (TAM) filing, UE 420.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. DA/RT

Q. Before explaining the DA/RT issue, please explain how PacifiCorp carries out wholesale power purchases and sales.

A. The Company conducts trades in the real-time and day-ahead markets in addition to "term" (defined as for the balance of the month out four years) trades. The trades are done through brokers, directly with counterparties, or bid into California Independent System Operator (CAISO) market. Factors used to make purchase or sale decisions are price, market liquidity, location, and transmission price and availability.[1]

Q. What sales and purchases are included in the 2024 TAM.

A. See CONF Figure 1 below, which shows the Company's **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in the forecast test period.[2] The Company details how the impact to Net Power Costs (NPC) of many modeling enhancements is driven by increased market purchases to cover a reduction in forecasted generation due to several factors such as coal supply and compliance with regulations.[3]

---

[1] See Staff/202, PAC response to DR 49 (pdf).

[2] See Staff/202, PAC response to DR 2 (pdf). See also Staff/203, DR 2 Attach (electronic spreadsheet) UE 400 to demonstrate an example of these costs. Please refer to the confidential work papers provided with the Company's response to TAM Support Set 1 (concurrent), specifically confidential file "_OR UE-420 ORTAM24_Mitchell Direct Mar 2023 CONF.xlsm", tab "NPC". Rows 20 through 30 provide the dollars associated with wholesale power sales. Rows 210 through 2020 provide the dollars associated with wholesale power purchases. Rows 354 through 364 provide the MWh associated with wholesale power sales. Rows 544 through 554 provide the MWh associated with wholesale power purchases.

[3] PAC/100 Mitchell/21, which discusses the environmental compliance requirement. PAC/100 Mitchell/22 discusses Jim Bridger Power Plant's natural gas conversion of Units 1 and 2. PAC/100 Mitchell/23 discusses the hydroelectric projects' removal. PAC/100 Mitchell/24 discusses the coal supply limitations.

CONF FIGURE 1. WHOLESALE MARKET PURCHASES AND SALES

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. How are customers served by PacifiCorp's market purchases?

A. Market purchases are a substitute for generation dispatch. Changes in generation dispatch are a function of the resource stack and customer load based on the principles of least cost dispatch given a set of operational constraints. This order is based upon the resources' marginal costs and the dispatch is based on the technology type within the operational constraints. In the context of NPC, the marginal cost of a resource is a measure of the variable cost incurred to serve the next MWh of customer load. Customer load is satisfied first by the resource at the bottom (with the lowest marginal cost) and then by going up the stack until the dispatch equals customer load.[4]

Q. What is the origin of the Day-Ahead/Real-Time Price Adjustment?

[4] See PAC/100, Mitchell/30-31 for a discussion on PacifiCorp's resource stack and servicing of customer load. Transmission costs can also be a factor in determining the least cost resource that can be delivered to the load.

A. The DA/RT adjustment was first proposed by PAC in 2015 UE 296 and approved in Order No. 15-394 to, "more accurately model day-ahead and real-time system balancing transactions".[5] System balancing transactions occur to balance hourly load and resources when PAC does not have enough owned or contracted resources to meet its load, or when the Company has excess resources for a given hour. When the Company proposed the adjustment, it described how the GRID model did not capture all system balancing costs therefore, an ad hoc adjustment was needed. The Company gives a similar rationale in this docket that balancing costs are not fully captured in NPC forecasts.[6]

Q. What is the Company's explanation of the DA/RT adjustment?

A. The Company explains the DA/RT adjustment includes two components to capture system balancing costs that are neither included in the Company's forward price curve nor modeled in GRID. The adjustment has a volume component and a price component. The volume component addresses the fact that the Company must transact in the market in set quantities (e.g. a 25 MW block); at the time Grid did not have this restriction and transacts all quantities of MW.[7] The price component produces different prices to better reflect prices in the real time market. In other words, average prices at the Mid-Columbia (Mid-C) were lower than what the Company paid when it made market

5 See UE 296 PAC Reply Testimony in PAC/500, Dickman/14 and also Order No. 15-394.
6 PAC/100, Mitchell/44.
7 UE 390, PAC/100, Webb/22.

purchases and higher than what it received for market sales.[8] In theory, the Company says that these prices account for the historical price differences between the Company's purchases and sales as compared to the monthly average power market-indexed prices.[9]

Q. The DA/RT was adopted to address claimed deficiencies in the GRID model. Why is it necessary now that PacifiCorp has switched to the AURORA model?

A. Staff was hopeful that the change to AURORA would eliminate the need for DA/RT as DA/RT was designed to address a GRID deficiency, but the Company has testified there is no AURORA feature that would address the issue.[10] PacifiCorp remains the only Oregon investor-owned utility applying such an adjustment to its power cost forecast, despite other utilities also using the AURORA Model. The Company briefly spoke to this question in UE 400 and stated the following:

> The Company has discussed the DA/RT adjustment with Energy Exemplar, including its purpose. Aurora does not currently have a feature or other functionality that could replace the need for the DA/RT adjustment. PacifiCorp will continue to explore the viability of possibly adding functionality to the Aurora model in the future."[11]

---

8 Order No. 16-482 page 11.
9 PAC/100 Mitchell/44.
10 UE 400, PAC/100, Wilding/22.
11 UE 400, PAC/100, Wilding/22.

Q. Has the Company had contact with Energy Exemplar to discuss this inefficiency?

A. The Company has stated that they have had oral discussions with Energy Exemplar to develop functional 25 megawatt (MW) increment multi-hour block trading functionality but that this would not resolve the "single state model" problem.[12]

Q. What is the "single stage model" problem?

A. As explained by the Company:

> "The purpose of the day-ahead / real-time (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 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 megawatt (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*)."

---

[12] See Staff/202, PAC response to DR 88 (pdf).

> "This inefficiency in actuals operations is not reflected in Aurora which has perfect foresight, perfect execution and is a single stage model which simulates *all* market transactions with unrealistic single one-hour block products at fractions of a MW."[13]

Q. Describe the steps to calculate the DA/RT adjustment.

A. Staff's confidential Data Request No. 48 asks the Company to document the adder steps as described by Staff in UE 400.[14] **[BEGIN CONFIDENTIAL]** [redacted]

---

13 See Staff/202, PAC response to DR 83 (pdf).

14 Staff/203, PAC CONF response to Staff DR 48 (pdf) and 48-1 CONF ATTACH (pdf) which asked for CONF DR response 92 from UE 400.

[redacted] [END CONFIDENTIAL]

Q. What has the Company proposed in UE 420?

A. PacifiCorp proposes the same change to the DA/RT adjustment that was proposed in UE 400, which is to change the price adders from a dollar value to a percentage of market prices. This is essentially an additional step beyond the first six steps described in the prior question and answer. UE 400, was resolved by a stipulation with no specific agreement of parties on this issue.[15] In the Company's opening testimony for UE 400, this change amounted to an increase to NPC of $5.21 million in order to change the adder from price-based to a percentage of prices to "capture intra-month market volatility".[16] Staff currently has an pending DR on the price impact for this year's TAM as it was not discussed by the Company.

Q. What is Staff's recommendation?

A. Staff has three recommendations. First, at this time Staff does not support the price adders being changed from dollar values to percentages. There has not been enough information provided to support this proposal in this docket and the Company provided no evidence that this change does in fact support "intra-month market volatility".[17] Therefore, Staff recommends adjusting total NPC

---

[15] UE 400 Order No. 22-389. Appendix A page 8 of 24.
[16] UE 400 PAC/100 Wilding/36.
[17] UE 400, PAC/100 Wilding/36.

downward by the impact of this adjustment from dollar values to percentages for price adders. Staff does not yet have the NPC impact for this year's TAM, therefore recommends a reduction to power cost of $5.21 million as a placeholder.

Second, Staff recommends that the inherent issues with the DA/RT be addressed holistically with the Company's perceived shortcomings of its market cap methodology, which is laid out in Staff/300. In short, the Company believes that the market cap methodologies used in the 2022 TAM and prior cases overstate off-system sales revenues while Staff and stakeholders have repeatedly brought up that the DA/RT adjustment understates off-system sales revenues. By choosing to address both of these through the market cap proposal, we anticipate that they will offset one another and lead to a more accurate and fairer picture of market sales and purchases. Lastly, Staff recommends that the Company hold workshops in future TAM filings to discuss adjustments made to the AURORA model.

Q. Provide some context on Staff's recommendation.

A. There has been a history of tension between the Company believing that GRID and AURORA over-forecast the benefits of trading at different market hubs even with market caps and Staff and stakeholders believing that the DA/RT adjustment under-forecasts those benefits. For example, in Docket No. UE 375, Staff recommended the Company hold a workshop regarding the DA/RT mechanism and the transition to AURORA for NPC forecasts and AWEC recommended a downward adjustment to PacifiCorp's NPC due to overestimation of the DA/RT market cost. In Docket No. UE 390, the parties agreed to conduct workshops addressing the DA/RT adder as well. Parties also resolved DA/RT adder issues with a stipulation, but approval of the stipulation did not represent the Commission adopting any specific methodology.[18] For example, in that docket, Staff recommended removing the DA/RT and adjusting the NPC down by more than $5 million, claiming that the model resulted in artificial losses by forcing purchase prices higher and sales prices lower in the model than in actual transactions.[19] Given that these two ad hoc adjustments have opposing effects on the same general subcategory of the total TAM forecast, Staff believes that they can be paired together to help the AURORA model match up better to reality and perhaps remove some recurring issues in future TAM proceedings. Staff wants to reiterate that we believe there are still inherent problems with the DA/RT and market caps, and we believe Staff's view moves closer to a final solution in a more holistic manner.

Q. Does Staff have any other concerns regarding PacifiCorp's DA/RT adjustment?

A. Yes. Staff is concerned about the lack of information in PacifiCorp's filing about this adjustment. The DA/RT adjustment has been a contentious issue since it was first proposed in 2015 and the proposed change from a dollar amount to a percent of market prices was contested in UE 400. Notwithstanding, PacifiCorp provides very little information in their filing or

---

[18] UE 400, Order No. 21-379.

[19] UE 400, Staff/200, Cohen-14-15. See also UE 375, Staff/200, Enright/52.

supporting workpapers about the DA/RT adjustment or their proposed change.[20] Frustratingly, the Company failed to submit the same workpaper that was used for much of Staff's analysis in UE 400 and that isolated the DA/RT adjustment.[21] It is worth noting that AWEC brought up a very similar concern in PacifiCorp's 2022 TAM, UE 390, testifying, "It appears that much of PacifiCorp's recommendation relies on an analysis that Staff performed in Docket UE 374. That information has not been provided in this docket." [22] Staff is unsure at this time on whether a recommendation is needed to ensure that PAC include supporting evidence in testimony and exhibits in future TAMs or whether this is already covered in the current Minimum Filing Requirements (MFRs).

Finally, Staff notes the Company ended up filing a list of corrections or omissions on June 2, which stated, "PacifiCorp has identified a correction related to the Day Ahead – Real Time (DA/RT) adjustment. The NPC impact of this correction has not yet been calculated and will be quantified in the Company's July Update."

Q. How has PacifiCorp responded to these concerns?

A. Yes. PacifiCorp states, "In line with the Public Utility Commission of Oregon (OPUC) Order No. 09-432, the Company will provide notice of substantial changes to the methodologies used to calculate NPC or notice of substantial

[20] See Staff/202, PAC response to DR 47 (pdf). The two workpapers identified are the Aurora GN Market Prices CONF and Mitchell NPC Report Workpaper.
[22] See UE 390 Opening Testimony AWEC/100 Mullins/12-13.
[22] See UE 390 Opening Testimony AWEC/100 Mullins/12-13.

changes to the logic of the NPC model by March 1st of the year of a stand-alone Transition Adjustment Mechanism (TAM) filing. The Company will include in its April 1st TAM filing a justification for each substantial change. However, significant testimony was provided in PacifiCorp's 2023 TAM in the Company's Direct and Reply testimony describing the modeling adjustments. The modeling adjustments (methodologies) carried over from PacifiCorp's 2023 TAM, Docket UE-400 are not changes, they are carried over wholly *unchanged* from the final update to the TAM in Docket UE-400."[23]

Q. Are there data request responses that Staff has not had a chance to review?

A. Yes. Staff has not reviewed responses to data request numbers 83-87, 89-90, and 92-98

[23] See Staff/202, PAC response to DR 99 (pdf).

ISSUE 2. STANDARD INPUTS AND ENERGY PRICE CHANGES

Q. Please summarize this issue.

A. Standard inputs refer to various cost items associated with operating power plants and other sources of power. The Standard inputs for review are heat rates, forced and scheduled maintenance outages, natural gas price forecast, Official Forward Price Curve (OFPC), fuel price, and minimum operating level. In general, Staff has reviewed the inputs and identifies no issues or recommendations for additional analysis or adjustments.

Q. What are heat rates?

A. Heat rates are one measure of efficiency of electrical generators/power plants that convert a fuel into heat and, in turn, into electricity. The heat rate is the amount of energy used to generate one kilowatt hour (kWh) of electricity and the U.S. Energy Information Administration (EIA) expresses them in British thermal units (Btu) per net kWh generated.[24] Staff reviewed heat rates from 2018 through the current year.[25] The Company's heat rate coefficients, as used to develop the 2024 transition adjustment mechanism (TAM), were derived from 48-months of historical information, where available.[26] See Confidential Figure 2 for a summary of actual heat rates for the recent full year (2022) sorted largest to smallest and what they are expected to be this test

[24] https://www.eia.gov/tools/faqs/faq.php?id=107&t=3.

[25] Staff/202, PAC response to DR 22 (pdf). The attachments referenced in their response are CONF but the initial pdf response was submitted non-confidentially.

[26] Staff/202, PAC response to DR 23 (pdf). The attachments referenced in their response are CONF but the initial pdf response was submitted non-confidentially.

year.[27] Those that are not included in this year's forecast are excluded from the chart for 2022 as well.

CONF FIGURE 2. HEAT RATES IN 2022 AND 2024

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. Does Staff have any recommendations on heat rates?

[27] Staff/203, See DR 22-2 CONF Attach titled 2022-12 PACHR Summary CONF.

A. Staff recommends that the Company explain what can be done to reduce the heat rates at the Jim Bridger Plant. Staff found that the full load heat rate of the converted gas units is expected to be **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. For comparison purposes, in 2021, the EIA reported that average heat rates were as follows: 10,583 (Coal), 11,223 (Petroleum), 7,687 (Natural Gas), and 10,429 (Nuclear).[29] This is discussed further in Staff/400.

Q. What is the Commission history on Forced Outage Rates?

A. Order No. 07-446 (UE 191) is where the Commission determined the Company should use a four-year average of plant outages to calculate plant forced outage rate for ratemaking purposes. The Commission also adopted an ICNU proposal to exclude outages attributable to management failure. Consistent with the method set forth in Order No, 10-414 and reiterated in Order No. 15-394 (UE 296), PacifiCorp still uses a four-year average of actual outage events to forecast plant outage duration and adjusts the average for lengthy individual plant outages.

---

28 See PAC CONF Work paper, Aurora GN Heat Rate Definitions CONF.

29 Sources: U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report," and predecessor form(s) including U.S. Energy Information Administration, Form EIA-906, "Power Plant Report;" and Form EIA-920, "Combined Heat and Power Plant Report;" Form EIA-860, "Annual Electric Generator Report." See also https://www.eia.gov/electricity/annual/html/epa_08_01.html.

Q. How did Staff investigate this issue?

A. Staff reviewed several data requests regarding the company's planned maintenance scheduling and reasons for maintenance and related outages.[30] In scheduling maintenance, the Company tries to avoid forecasted peak system needs while considering other factors such as the availability of qualified contractors, weather conditions at the plant needing the work, system obligations during proposed schedule, and wholesale market power costs.[31] The sum for both the duration of outage and the mWh lost are the most important columns to note in PacifiCorp's data request responses. See conf figure 3 below for a summary table of planned outages for thermal plants. For simplicity purposes to display the plant outages, those for individual units were combined. For example, Jim Bridger units 1 through 4 are summed under the heading Jim Bridger below to give an idea of the outages and mWhs lost at different unit locations.[32]

[30] See Staff/202, PAC response to Staff DR 21 (pdf) and DR 22 (pdf). See also Staff/203, CONF response to DR 21-1 Attachment (electronic spreadsheet) and DR 22-1 Attachment (electronic spreadsheet)

[31] Staff/202, PAC response to Staff DR 20.

[32] See Staff/203, PAC response to DR 21-Attachment 2 titled 2018-2022 Actual Planned-Maint Thermal Outages CONF.

CONF FIGURE 3. THERMAL PLANT OUTAGES

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. What is the Commission history on the Official Forward Price Curve (OFPC)?

A. Order No. 11-435 (UE 227) provides the use of the internally generated Forward Price Curves is permissible. Order No. 11-435 (UE 227) specifies that applying scalars to forward price curve to obtain an hourly market price profile is permissible. Order No. 15-394 (UE 296) is where the Commission seemed persuaded that short-term power purchase prices systematically exceed short-term power sales prices, and that the DA/RT adjustment can account for these expected price differences.

Q. How is the OFPC Derived?

A. "For PacifiCorp's official forward price curve (OFPC), the first 36 months of the OFPC (the portion of the OFPC relevant to the transition adjustment mechanism (TAM) analysis), is determined by market data from third-party brokers. The Company receives quotes for liquid delivery hubs which are considered "primary" hubs. Other hubs in the OFPC are considered "secondary" and their price is formulated using a basis spread from the most relevant primary hub."[33]

Q. What additional details are relevant with regards to the OFPC?

A. The Company uses the December 31, 2022, forward price curve for the 2024 TAM. The July 2023 Update is expected to use the Company's June 30, 2023, OFPC.[34] 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. Has there been a change in energy prices since the last TAM?

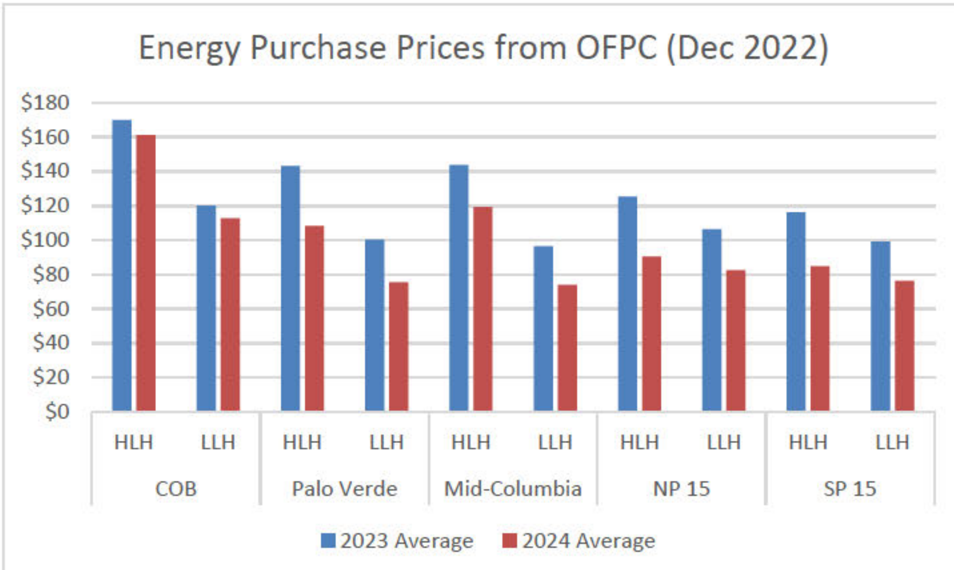
A. Staff examined several resources including the Official Forward Price Curve, data from the Intercontinental Exchange (ICE), as well as the Company's own testimony, all of which point to decline in energy prices being expected from 2023 to 2024. For comparison to the forecasted Mid-C prices below for 2023 and 2024, the average for 2022 Peak Mid-C historical data was

[33] See Staff/202, PAC response to DR 53 (pdf). Staff/203 PAC CONF response to Attachment OPUC 53 which provides the most recent TAM broker comparison sheet. See also PAC/100 Mitchell/5 Lines 12-14.

[34] See Staff/202, PAC response to DR 54 (pdf).

$101.67 for high prices and $86.26 for low prices, indicating an increase from 2022 to 2023 and a decrease from 2023 to 2024.[35]

FIGURE 4. ENERGY PURCHASE PRICES FROM OFPC DECEMBER 2022[36]



[35] U.S. Energy Information Administration - EIA - Independent Statistics and Analysis
[36] PAC Workpaper 1222 Official Forward Price Curve_20221230 NON-CONF.

ISSUE 3. NPC VALIDATION FOR A LARGE INCREASE IN REQUESTED POWER COSTS

Q. What is Net Power Costs (NPC) Validation?

A. NPC is the sum of fuel expenses, wholesale purchase power expenses, and wheeling expenses, less wholesale sales revenue. Their NPC validation is meant to confirm whether or not, absent any ad hoc adjustments, that PacifiCorp's Aurora model reasonably represents actual costs of supplying power.

Q. What support does the Company provide to demonstrate that the 2023 forecast was lower than it should have been?

A. First, there is a strong correlation between NPC and Power Market Prices; and second, there are five new impacts to NPC that are not captured in the historical data or trend. Essentially the Company states that 2024 is reasonable since 2023 was a lower estimate due to the updates that were not included in the past TAM and a change in the expected costs in the future.

Q. Does Staff find this argument compelling?

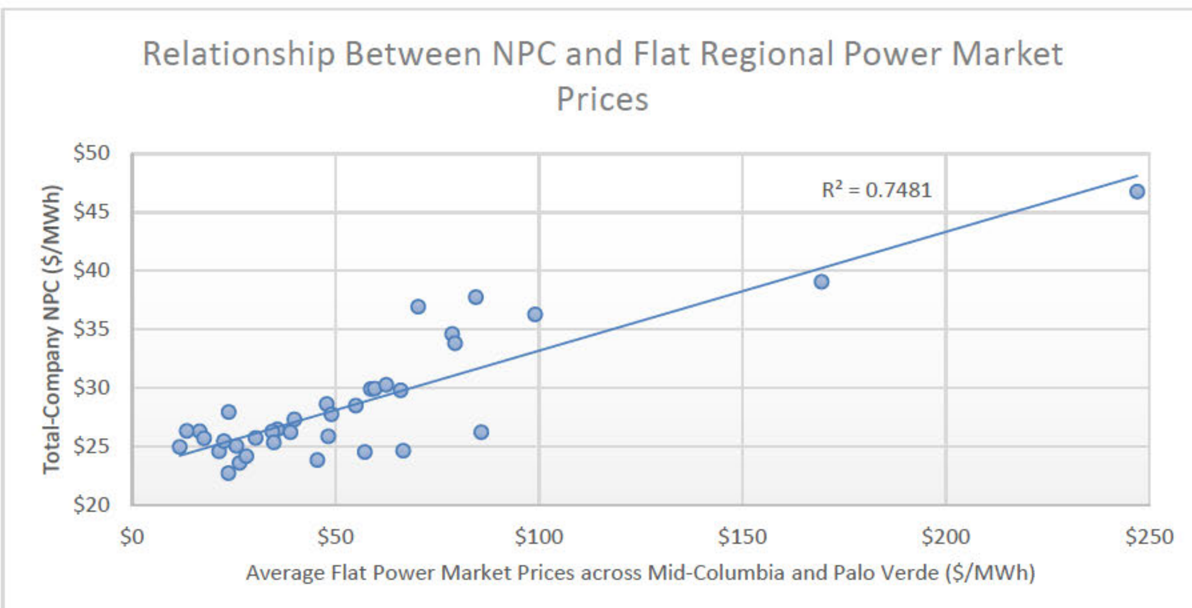
A. No, for the following reasons:

- One, as you can see below in Figure 1, the Company uses prices across just Mid-Columbia and Palo Verde to demonstrate its point for 2020 to 2022, despite having access to other hubs as well.[37]

[37] See Staff/202, PAC response to DR 103 (pdf), in which the Company states, "The Company operates two balancing authority areas (BAA), PacifiCorp West (PACW) and PacifiCorp East (PACE). Mid-Columbia (Mid-C) is a trading hub representative of PACW, and Palo Verde (PV) is a trading hub representative of PACE."

- Two, PacifiCorp simply uses the correlation that it found between Total Company NPC and Market prices to find a hypothetical spot on its line for the year 2024.
- Three, PacifiCorp states that the 2024 forecast looks large because it is considering modeling changes that were not included in the 2023 forecast. Staff wants to reiterate that each TAM gives parties a chance to propose modeling changes and using that as justification for the current forecast does not hold water.

FIGURE 5. RELATIONSHIP BETWEEN NPC AND POWER MARKET PRICES[38]



[38] As seen in PAC/100.

Q. What specific reasons does the Company give for its large increase in power cost request?

A. First, wholesale power, natural gas and coal prices for calendar year 2023 have increased by an average of 31%, 20%, and 12%. Also, Mid-Columbia and Palo Verde hubs increased by 31% and Sumas and Opal have increased by 20%.

Second, the NPC forecast in the 2023 Tam excluded the impacts of the Washington cap and invest program; and, also excluded the impacts of the ozone transport rule (OTR).

Third, the hedges in the 2023 Tam were favorable to the current calendar year and 2023 market prices from the OFPC used in this filing. In addition, PacifiCorp states that when hedges lower NPC, it is coincidental not a guaranteed outcome.

Fourth, the calendar year 2023 OR load projections used to calculate the 2023 Tam were substantially lower than the current calendar year 2023 load projections.

Q. How does Staff rebut those claims?

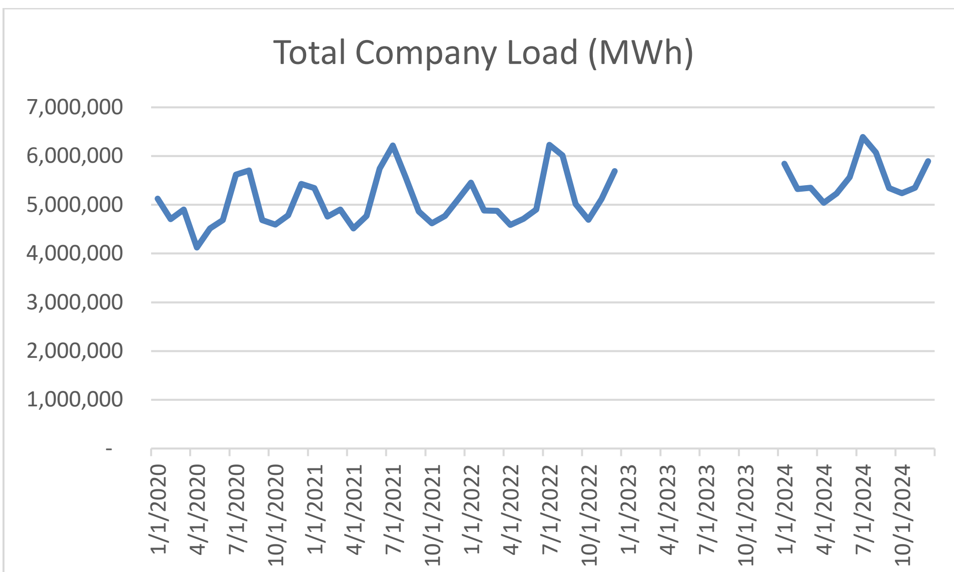
A. It is true that PacifiCorp used the November 8, 2022 OFPC to set expectations for 2023 and that if PacifiCorp did use the December 31, 2022 OFPC, NPC would be higher. Yet, if Staff were to use that same logic and look at the OFPC for March 2022, we can see that it has since come down.

Also, there were no costs associated with the Washington Cap and Invest Program and the Ozone Transport Rule in 2023, so it is inappropriate to include them in a comparison between the 2023 and 2024 forecast.

And the Company wants to assume there are neither economic benefits nor costs from hedging transactions, which is not true.

Finally, yes, on a dollar basis, higher load does lead to higher NPC. However, when reviewing the Company load, as you can see in Figure 6 below, it has been variable and does not continually increase.

FIGURE 6. TOTAL COMPANY LOAD[39]



Q. What additional evidence does the Company provide for its elevated 2023 figure?

A. After these four factors are considered, for comparison purposes, the 2023 NPC comparison forecast updates to approximately \$2.628B (system).

39 See PAC Workpaper MitchellTestSupp_Table1_Figure1_2 NON-CONF. 2023 Load was not included in this workpaper.

Additionally, the 2023 Jim Bridger gas conversion and the 2024 Klamath River hydroelectric projects' deconstruction are not accounted for in this 2023 value. The NPC impacts of these 2024 operational changes total $146M total Company. So, if these impacts had been included in the 2023 forecast, this would have raised the 2023 NPC forecast to $2.774B for 2023. For comparison, the 2024 forecast is $2.642B. Therefore, the Company believes it 2024 is actually a decrease to NPC.

Overall, the Company tries to obfuscate what the actual cost contributors are by having multiple discussions that seemingly contradict one another or providing different evidence on what those cost contributors are. In addition, in the actual step log, the Company picks and chooses what modeling updates are highlighted versus what updates are lumped together and considered "routine". Figure 7 below displays the total forecast for 2024.

FIGURE 7. NPC RECONCILIATION DOLLARS

Table 2: NPC Reconciliation Dollars

Net Power Cost Reconciliation		
	($ millions)	$/MWh
OR 2023 TAM Forecast[1]	**1,996**	**32.30**
Increase/(Decrease) to NPC:		
Wholesale Sales Revenue	137.0	
Purchased Power Expense	159.2	
Coal Fuel Expense	(87.9)	
Natural Gas Fuel Expense	427.1	
Wheeling and Other Expense	10.8	
Total Change to NPC	**646.2**	
OR 2024 TAM Forecast	**2,642**	**39.65**

[1] This forecast does not include the impact of the OTR, the Washington Cap and Invest Program or the settled unspecified monetary adjustment of $18.9 million total-company.

Table 3: NPC Reconciliation Energy

Net Power Cost Reconciliation		
	MWh	$/MWh
OR 2023 TAM Forecast	**61,802,663**	**32.30**
Change to Net System Load:		
Wholesale Sales Decrease	2,946,233	
Purchased Power Increase	3,880,420	
Coal Generation Decrease	(10,065,681)	
Natural Gas Generation Increase	8,876,822	
Other Generation Decrease	(815,569)	
Total Change to Net System Load	**4,822,225**	
OR 2024 TAM Forecast	**66,624,888**	**39.65**

ISSUE 4. BACKCAST/BENCHMARKING/MODEL VALIDATION

Q. Describe the origin of the backcast request.

A. In UE 323, Staff and ICNU questioned the accuracy of GRID and wanted the Company to conduct GRID runs using actual historical input values so that parties could compare the results to historic realized NPC. At the time, Staff believed that it would explain whether forecast errors are related to inputs (such as gas prices) or model specification (such as missing model inputs or inappropriate model mechanics).[40] Order No. 22-389 stated that,

> "PAC will produce two benchmarking studies in the Aurora model, one in the 2024 TAM and one in the 2025 TAM. PAC will make best efforts to provide parties a benchmarking study that uses inputs from 2019 actuals on February 1, 2023. PAC will make best efforts to provide a second benchmarking study that used inputs from 2020 actuals on February 1, 2024."

Q. Please describe the model validation process for Aurora as provided by PacifiCorp in the 2024 TAM.

A. In advance of the 2024 TAM, PacifiCorp performed a benchmarking study that uses inputs from 2019 actuals.[41] PacifiCorp verified that the variation in total NPC between the 2019 actuals and 2019 simulated was about 4.5 percent.

---

[40] UE 323, Staff/500 Kaufman/3. See also Order No. 17-444, page 4.
[41] Docket No. UE 400 PacifiCorp/100, Mitchell/28.

Q. Describe what Staff was expecting from PAC's benchmarking study.

A. For reference, the excerpt below from PacifiCorp's testimony in the 2019 TAM (UE 339) describes the backcast that was defined and agreed to by parties in Order No. 17-444 in UE 323:

> 1) Base year is 2016.
> 2) Base inputs are the final 2016 TAM update inputs.
> 3) Replace forecast market energy prices with actual hourly prices for each hub with three different scenarios:
>   a. POWERDEX Prices;
>   b. PacifiCorp actual real time transaction prices; or
>   c. Historic Monthly prices shaped using scalers.
> 4) Replace forecast natural gas prices with actual natural gas prices.
> 5) Replace forecast load with actual hourly load.
> 6) Replace forced outage rate and planned outages with actual outages and actual derates.
>   a. Run with/without scenarios for economic shutdowns.
> 7) Replace forecast wind profile with actual wind profile.
> 8) Replace forecast hydro conditions with actual hydro conditions.
> 9) Run a sensitivity study with market caps on and off.
> 10) Use actual generation profile for long term contracts, PPAs and QFs.
> 11) Option contracts will be optimized by GRID.
> 12) Run a sensitivity with actual market transactions of duration greater than 7 days.
> 13) Use actual heat rate curve.
> 14) The following items will be updated to reflect major changes not captured in TAM:
>   a. Wheeling Costs including long term contract changes; and
>   b. Incremental Coal costs including transport costs.
> 15) Update Jim Bridger costing tier prices to reflect actual Jim Bridger coal costs.[42]

Q. What are the results from the backcast for 2019 actuals against the Aurora forecast?

A. For most cost categories, Aurora has accurately predicted actual values within a margin of error. However, Staff is unsure of the reason **[BEGIN**

[42] Docket No. UE 339 PAC/100, Wilding/17-18.

CONFIDENTIAL] [redacted] **[END CONFIDENTIAL]** The Company further responded that, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[43]

Q. Did the Company perform an apples-to-apples comparison to make the backcast results more useful?

A. No. The Company has responded to Staff's request to make an apples-to-apples comparison by stating, "To appropriately incorporate Energy Imbalance Market (EIM) benefits into each cost/revenue component would require incorporating the fifteen-minute scheduling/dispatch of the EIM into Aurora's optimization. However, the Company does not have 15-minute or five-minute forecasts of the modeling inputs inclusive of forecasts of 15-minute or five-minute prices that are necessary to attempt such a modeling endeavor."[44] See

---

[43] See Staff/203, PAC response to DR 104 (pdf).
[44] See Staff/202, PAC response to DR 109 (pdf).

CONF Figure 8 for the summary table included in PacifiCorp's opening testimony.

CONF FIGURE 8. BENCHMARKING STUDY SUMMARY

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. Are there additional comments on the benchmarking study?

A. When Staff compared the table above to their actual 2019 NPC report, Staff sees that the numbers do match up. However, these are not the values that are used in the PCAM, as identified in DR 1-5 Attach, tab 2019 PCAM. Staff is unsure of the difference in these excels. The value that PacifiCorp uses in the PCAM document is $1,656,127,508, which is around $4,000,000 less than actual. In theory, both of these values are supposed to represent actuals for 2019.

Q. What price component does the Benchmarking study highlight that the AURORA model is not as accurate at forecasting.

A. **[BEGIN CONFIDENTIAL]** [redacted][45] **[END CONFIDENTIAL]** Staff has reviewed

[45] *In the Matter of PacifiCorp Request for a General Rate Revision*, Docket No. UE 374, Order No. 20-4 73 at 130 (Dec 18, 2020) (citations omitted). See also Order No. 21-379 in UE 390.

four data requests on the discrepancies for each of the price components above, in which PacifiCorp generalizes by stating, **[BEGIN CONFIDENTIAL]** [redacted][46] **[END CONFIDENTIAL]** Lastly, Staff is working to gain access and familiarity with the AURORA Model.

Q. Does this conclude your testimony?

A. Yes.

[46] See Staff/203, PAC CONF response to DR 104 (pdf), 105 (pdf), 106 (pdf), and 107 (pdf).

CASE: UE 420
WITNESS: JULIE JENT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 201

Witness Qualifications Statement

June 23, 2023

WITNESS QUALIFICATIONS STATEMENT

NAME: Julie Jent

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Utility Analyst
Rates, Finance and Audit Division

ADDRESS: 201 High Street SE. Suite 100
Salem, OR. 97301

EDUCATION: I have a Bachelor of Science from Berea College in Political Science where I concentrated on economics and the regions of Eastern Europe and Southeastern Asia. I also hold a Masters of Integral Economic Development Policy specializing in the public sector and econometrics.

EXPERIENCE: I have been employed as a Junior Financial Analyst by the Oregon Public Utility Commission since June 2021 in the Telecommunications and Water division. I transitioned to the Rates, Safety and Utility Performance Division in July of 2022 within the Energy Costs section. Within this division, I currently perform a range of financial analysis duties related to natural gas, electric, and water utilities, with a focus on operations and maintenance. In addition, I assist with Purchased Gas Adjustments, Annual Power Cost filings, and General Rate Cases. Past rate cases include UG 435 and UE 399. I was previously employed as an adjunct professor of Econometrics at the Catholic University of American and as an Analyst in the Office of Management and Budget (OMB) within the Executive Office of the President (EOP), where I worked as part of a team on education funding. Prior to EOP, I was an Economic Consultant for the U.S. Conference of Catholic Bishops.

CASE: UE 420
WITNESS: JULIE JENT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 202

Exhibits in Support
Of Opening Testimony

June 23, 2023

UE 420 / PacifiCorp
June 6, 2023
OPUC Data Request 49

OPUC Data Request 49

Wholesale Power Purchases and Sales - Please provide a narrative explanation of how PAC carries out wholesale purchases, including details of:

(a) Which timeframes are trades enacted in, including a definition of each timeframe referenced. Please specify which actuals correspond to which forecasted amounts.

(b) How trades are enacted, e.g. through markets, counterparties, brokers, other.

(c) What factors are taken into account when deciding to purchase power.

(d) How does owned transmission capacity, or transmission capacity available for purchase, factor into the Company's decision to purchase power.

(e) What communication takes place between PAC's power purchasing team and the wider group to inform power purchases.

(f) What reference prices are taken into account when choosing to purchase power. If this response differs according to the timeframe, please provide a separate response for each timeframe.

(g) The interplay between risk management and power purchases.

Response to OPUC Data Request 49

The Company assumes that the reference to "PAC" is intended to be a reference to PacifiCorp. Based on the foregoing assumption, the Company responds as follows:

(a) Trades are enacted in the following time frames: the real-time market (defined as next hour through the current day), day-ahead (defined as for the next day or days as defined by the pre-schedule calendar), or term trades (defined as for the balance of the month out four years).

(b) Trades are enacted through brokers, directly with counterparties or bid into the California Independent System Operator (CAISO) market.

(c) Factors used to make purchase or sale decisions are price, market liquidity, location and transmission price and availability.

(d) Transmission capacity must be available to move power from the market point to a sink. If transmission is not already owned, then the cost of purchasing the transmission is considered into the total price when making a decision to purchase or sell power.

(e) The Company's weekly Commercial Objectives Report (COR) informs the relevant groups within the Company of power purchases and sales, as well as routine communications amongst trader both day-ahead and real-time.

(f) The reference prices used when making purchasing decisions include broker quotes and price quotes received directly from counterparties.

(g) The PacifiCorp's Energy Risk Management Policy provides rules for making purchases and sales.

OPUC Data Request 2

General - Regarding the Company's forecasts and actuals:

(a) Please provide a breakdown of the power resources included in the Company's final Net Variable Power Cost forecast for each year from 2014 through 2024. Please provide:

i. Total volume of power forecasted from each resource type (e.g. wind, market purchases, solar natural gas)
ii. Total cost in US dollars of each resource type.
iii. Average per MWh cost in US dollars for each resource type.

(b) Please provide a breakdown of the power resources included in the Company's 2024 Net Variable Power Cost forecast. Please provide:

i. Total volume of power forecasted from each resource type.
ii. Total cost in US dollars of each resource type. iii. Average per MWh cost in US dollars for each resource type. iv. If the above information is already provided, detail which work paper this can be found in.

(c) Please provide a breakdown of the actual power resources used by the Company for each year from 2014 through 2023. Please provide:

i. Total volume of power produced by each resource type.
ii. Total cost in US dollars of each resource type.
iii. Average per MWh cost in US dollars for each resource type.

Please provide the requested details for each resource type separately. Provide QF resource types separately to non-QF resources of the same type. For power purchases and sales, provide long-term power contracts (>1 year) separately to short-term firm power purchases and sales and system balancing purchases and sales.

This is an ongoing request. Please update this response following each of the Company's update filings and provide updates to requested data for 2023 as it becomes available.

Response to OPUC Data Request 2

PacifiCorp objects to this request as overly broad, unduly burdensome and not reasonably calculated to lead to the discovery of admissible evidence. Without waiving the foregoing objection, PacifiCorp responds as follows:

The Company assumes that the reference to "Net Variable Power Costs" refers to net power costs (NPC); the Company assumes that the terms net variable power costs (NVPC) and NPC are interchangeable.

In addition, the Company interprets this request for “included in the Company’s final Net Variable Power Cost forecast for each year from 2014 through 2024” to be asking for information from PacifiCorp’s transition adjustment mechanism (TAM) proceedings from the following dockets:

Docket UE-264 (forecast year 2014 TAM)
Docket UE-287 (forecast year 2015 TAM)
Docket UE-296 (forecast year 2016 TAM)
Docket UE-307 (forecast year 2017 TAM)
Docket UE-323 (forecast year 2018 TAM)
Docket UE-339 (forecast year 2019 TAM)
Docket UE-356 (forecast year 2020 TAM)
Docket UE-375 (forecast year 2021 TAM)
Docket UE-390 (forecast year 2022 TAM)
Docket UE-400 (forecast year 2023 TAM)
Docket UE-420 (forecast year 2024 TAM) – this proceeding

Based on the foregoing assumption and interpretation, the Company responds as follows:

(a) Please refer to the Confidential Attachment OPUC 2 which provides the final net power costs (NPC) reports from each Oregon transition adjustment mechanism (TAM) proceeding covering forecast years 2014 through 2023 (Docket UE-264 through Docket UE-400). The requested information is provided in the Company’s NPC reports, specifically tab “NPC” in each of the provided files (in dollars ($), megawatt-hours (MWh) and $/MWh). Note: Final NPC for the 2024 TAM are not yet available.

(b) Please refer to the concurrent confidential work papers supporting the direct testimony of Company witness, Ramon J. Mitchell, provided with the Company’s response to TAM Support Set 1 (concurrent), specifically confidential folder “NPCReport”, confidential file “_OR UE-420 ORTAM24_Mitchell Direct Mar 2023 CONF.xlsm”, tab “NPC” (in $, MWh and $/MWh). The Company will supplement this response with additional information as it becomes available during the course of this proceeding.

(c) Please refer to the Company’s response to OPUC Data Request 1 subpart (b). The actual NPC reports provide $ and MWh. $/MWh can be calculated by dividing $ by MWh.

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.

UE 420 / PacifiCorp
June 20, 2023
OPUC Data Request 88

OPUC Data Request 88

DA/RT - Why is the DA/RT adjustment still applicable in Aurora?

(a) Please include any communication with Energy Exemplar explaining why Aurora does not have a similar feature and/or supporting the use of this adder.

Response to OPUC Data Request 88

The Aurora model, like its predecessor the Generation and Regulation Initiative Decision Tools (GRID) model, is a single stage model. Please refer to the Company's response to OPUC Data Request 83 for further detail on the problem with a single stage model.

(a)The Company has held oral discussions with Energy Exemplar to develop functional 25 megawatt (MW) increment multi-hour block trading functionality. However, this would not resolve the "single stage model" problem.

UE 420 / PacifiCorp
June 20, 2023
OPUC Data Request 83

OPUC Data Request 83

DA/RT - What was the original purpose of the DA/RT adjustment when it was originally accepted by the Commission?

(a) Has that purpose changed?

Response to OPUC Data Request 83

The purpose of the day-ahead / real-time (DA/RT) adjustment is to more accurately capture the true cost of balancing the Company's system in the shortterm markets by: (1) adjusting forward market prices 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 megawatt (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***).

This inefficiency in actuals operations is not reflected in Aurora which has perfect foresight, perfect execution and is a single stage model which simulates ***all*** market transactions with unrealistic single one-hour block products at fractions of a MW.

(a) No. The purpose of the DA/RT adjustment has not changed.

UE 420 / PacifiCorp
June 6, 2023
OPUC Data Request 47

OPUC Data Request 47

DA/RT - State which work papers are associated with DA/RT.

Response to OPUC Data Request 47

Please refer to the confidential work papers provided with the Company's response to TAM Support Set 2 (5-business day), specifically confidential file "Aurora GN Market Prices CONF.xlsb".

Please also refer to net power costs (NPC) reports provided with the Company's response to TAM Support Set 1 (concurrent), specifically tabs: "STF DA-RT", "STF DA-RT Leap", "STF DA-RT Hourly", and "STF DA-RT Hourly Leap" in each NPC report.

UE 420 / PacifiCorp
June 20, 2023
OPUC Data Request 99

OPUC Data Request 99

DA/RT - Detail why supporting information for the DA/RT proposal was not provided in UE 420 aside from a footnote referencing testimony from a prior docket.

(a) Is this a practice that is customary for PacifiCorp?

Response to OPUC Data Request 99

PacifiCorp objects to this request to the extent it requires any legal analysis or a conclusion. Without waiving the foregoing objection, PacifiCorp responds as follows:

In line with the Public Utility Commission of Oregon (OPUC) Order No. 09-432, the Company will provide notice of substantial changes to the methodologies used to calculate NPC or notice of substantial changes to the logic of the NPC model by March 1st of the year of a stand-alone Transition Adjustment Mechanism (TAM) filing. The Company will include in its April 1st TAM filing a justification for each substantial change.

However, significant testimony was provided in PacifiCorp's 2023 TAM in the Company's Direct and Reply testimony describing the modeling adjustments. The modeling adjustments (methodologies) carried over from PacifiCorp's 2023 TAM, Docket UE-400 are not changes, they are carried over wholly ***unchanged*** from the final update to the TAM in Docket UE-400.

(a) Please refer to the Company's response above.

UE 420 / PacifiCorp
May 10, 2023
OPUC Data Request 22

OPUC Data Request 22

Standard Inputs - Please provide the following information in Excel format:

(a) Projected heat rates for each unit, as reflected in rates for each test year from 2018 through 2024.

(b) Actual heat rates for each unit, for each test year from 2018 through 2023.

Response to OPUC Data Request 22

The Company assumes that this request regarding "heat rates for each unit" is intended to be asking for information about heat rates of PacifiCorp's owned thermal resources.

In addition, the Company interprets this request for "each test year from 2018 through 2024" to be asking for information from PacifiCorp's transition adjustment mechanism (TAM) proceedings from the following dockets:

Docket UE-323 (forecast year 2018 TAM)
Docket UE-339 (forecast year 2019 TAM)
Docket UE-356 (forecast year 2020 TAM)
Docket UE-375 (forecast year 2021 TAM)
Docket UE-390 (forecast year 2022 TAM)
Docket UE-400 (forecast year 2023 TAM)
Docket UE-420 (forecast year 2024 TAM) – this proceeding

Based on the foregoing assumption and interpretation, the Company responds as follows:

(a) For forecast heat rate data from the 2018 TAM through the 2023 TAM, please refer to Confidential Attachment OPUC 22-1.

For forecast heat rate data in this 2024 proceeding, please refer to 5-day confidential work papers supporting the direct testimony of Company witness, Ramon J. Mitchell, provided with the Company's response to TAM Support Set 2 (5-business day), specifically confidential folder "All_DataSeriesFiles CONF", confidential file "Aurora GN Heat Rate Definitions CONF.xlsx".

(b) Please refer to Confidential Attachment OPUC 22-2 which provides actual heat rate data for calendar years 2018 through 2022. Note: actual heat rate data for calendar year 2023 is not yet available. The Company will supplement this response when additional information becomes available.

UE 420 / PacifiCorp
May 10, 2023
OPUC Data Request 23

OPUC Data Request 23

Standard Inputs - Please provide a narrative explanation of how PacifiCorp calculated its forecast of heat rates for the 2024 test year.

Response to OPUC Data Request 23

The Company assumes that this request is about the heat rate computation of Company owned thermal resources. Based on the foregoing assumption, the Company responds as follows:

The Company owned thermal resources' heat rate coefficients, used in the 2024 transition adjustment mechanism (TAM) initial filing were derived from 48months of historical information, where available. Source coefficients are on a 100 percent plant basis and adjusted for the ownership level. Please refer to the 5day confidential work papers supporting the direct testimony of Company witness, Ramon J. Mitchell, provided with the Company's response to TAM Support Set 2 (5-business day), specifically folder "All_DataSeriesFiles CONF", confidential file "Aurora GN Heat Rate Definitions CONF".

UE 420 / PacifiCorp
May 10, 2023
OPUC Data Request 21

OPUC Data Request 21

Standard Inputs - Please provide the following information in Excel format:

(a) Projected scheduled outage rates for each unit, as reflected in final rates for each test year from 2018 through 2023.

(b) The dates, duration, and cause of scheduled outages occurring between 2018 and 2023.

(c) The dates, duration, and cause of scheduled outages forecasted for 2024. If the values used in this filing are expressed in a different manner than in the Company's responses to subpart (a) and subpart (b), please provide both values.

(d) The minimum operation level and maximum output level of each unit.

(e) Provide these for each generating unit including renewables.

Response to OPUC Data Request 21

The Company assumes that this request regarding "scheduled outage rates for each unit" is intended to be asking for information about planned outages / planned maintenance of PacifiCorp's owned hydroelectric, thermal and wind resources.

In addition, the Company interprets this request for "each test year from 2018 through 2023" to be asking for information from PacifiCorp's Transition Adjustment Mechanism (TAM) proceedings from the following dockets:

Docket UE-323 (forecast year 2018 TAM)
Docket UE-339 (forecast year 2019 TAM)
Docket UE-356 (forecast year 2020 TAM)
Docket UE-375 (forecast year 2021 TAM)
Docket UE-390 (forecast year 2022 TAM)
Docket UE-400 (forecast year 2023 TAM)

Based on the foregoing assumption and interpretation, the Company responds as follows:

(a) Please refer to Confidential Attachment OPUC 21-1 which provides the supporting confidential work papers for the forecasted planned outages included in each of the TAM forecast calendar years 2018 through 2023.

Please refer to the information provided above to cross-reference to the relevant TAM docket numbers.

Note: because the forecast of renewable generation is a normalized forecast based on historical generation without removal of any time periods within the look-back horizon, renewable outages are reflected within the normalized forecast itself.

(b) Please refer to Confidential Attachment OPUC 21-2 which provides the outage logs for scheduled / planned / maintenance outages that occurred during calendar years 2018 through 2022. The information provided is for the Company's owned hydroelectric, thermal and wind resources, where available and applicable. Note: calendar year 2023 data is not available at this time.

(c) Please refer to the 5-day confidential work papers supporting the direct testimony of Company witness, Ramon J. Mitchell, provided with the Company's response to the TAM Support Set 2 (5-business day), specifically confidential folder "All_DataSeriesFiles CONF", confidential file "Aurora GN Maintenance Schedule_Planned CONF". Note: these are scheduled (planned) outages for maintenance and consequently the cause is the need for maintenance.

Note: because the forecast of renewable generation is a normalized forecast based on historical generation without removal of any time periods within the look-back horizon, renewable outages are reflected within the normalized forecast itself.

(d) For maximum output levels, please refer to the 5-day confidential work papers supporting Mr. Mitchell's direct testimony, provided with the Company's response to the TAM Support Set 2 (5-business day), specifically confidential folder "All_DataSeriesFiles CONF", confidential file "Aurora GNw Resource Table Thermal CONF.xlsx", column "Capacity" on the first tab. For minimum operation levels, please refer to Confidential Attachment OPUC 21-3.

(e) Please refer to the Company's responses to subparts (a) through (d) above.

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.

UE 420 / PacifiCorp
May 10, 2023
OPUC Data Request 20

OPUC Data Request 20

Standard Inputs - Does the scheduling of maintenance minimize power costs to customers, or are there other considerations taken into account by the Company?

Response to OPUC Data Request 20

Scheduling planned maintenance allows the Company to try to minimize net power costs (NPC) for customers, while ensuring that needed maintenance is completed, as well as meeting the Company's commitment to deliver affordable and reliable energy to customers.

When making decisions for the scheduling of planned maintenance, the Company considers a number of factors, including but not limited to, the availability of qualified contractors, weather conditions at the plant needing the work, type of work needed, system obligations during the scheduled proposed outages, and market power costs. The Company tries to schedule planned outages to avoid forecasted peak system needs, i.e. peak summer obligations and peak winter obligations.

OPUC Data Request 53

Standard Inputs - Please provide a narrative explanation of how the OFPC is derived, including references to specific work papers provided to Staff by PacifiCorp, and cells within those work papers. Please also include a discussion of:

(a) How owned transmission capacity, or transmission capacity available for purchase, factors into the Company's power price forecast.

(b) How the forecast treats different hours.

(c) How the forecast treats different nodes/delivery points.

(d) How recent price spikes affect the forecast.

(e) What inputs are used in the forecast, identifying the source of each including their unique reference e.g. "ticker"

Response to OPUC Data Request 53

For PacifiCorp's official forward price curve (OFPC), the first 36 months of the OFPC (the portion of the OFPC relevant to the transition adjustment mechanism
(TAM) analysis), is determined by market data from third-party brokers. The Company receives quotes for liquid delivery hubs which are considered "primary" hubs. Other hubs in the OFPC are considered "secondary" and their price is formulated using a basis spread from the most relevant primary hub. Please refer to Confidential Attachment OPUC 53 which provides the most recent TAM broker comparison sheet.

Broker quotes for primary hubs can be quoted in monthly, quarterly, or calendar year granularity, though not all brokers quote the same hubs or granularity. Where broker quotes are available, OFPC prices are within +/- 5 percent of said broker average.

Please refer to Confidential Attachment OPUC 53 for the most recent TAM broker comparison sheet, which provides the quotes utilized for forming the prices of several hubs. Four Corners (4C) is considered a secondary hub as it is not liquid enough for brokers to provide daily quotes.

(a) Transmission capacity is not an input to the first 36 months of the OFPC.

(b) Hourly prices are derived by applying hourly scalars to on-peak and off-peak prices. There are three sets of 24-hour hourly scalars per month for PacifiCorp West (PACW) and PacifiCorp East (PACE). The three scalars are Monday-
Friday, Saturday, and Sunday/North American Electric Reliability Corporation (NERC) holidays. The hourly scalars are calculated using the

most recent 24 months of California Independent System Operator (CAISO) day-ahead hourly prices for Malin (for PACW) and Palo Verde (PV) (for PACE). The scalars are calculated as the average price of the hour in the 24month dataset divided by the average price of the hours for the high load hour (HLH) or light load hour (LLH) time period in the 24-month dataset.

(c) Please refer to the Company's response to subpart (a) above.

(d) Historical prices are not an input to the on-peak and off-peak forward prices observed in the market on the day an OFPC is produced. Historical hourly prices are used to calculate hourly scaled prices. The hourly scalars are calculated using the most recent 24 months of California Independent System Operator (CAISO) day-ahead hourly prices for Malin (for PACW) and PV (for PACE). The use of 24 months of price data moderates, but does not lose, the effect of a historical price spike on the resulting hourly scalars.

(e) Quotes from three brokers for the primary curves are the inputs to the first 36 months of the OFPC. There is no universally used "ticker" for each hub. Please refer to the list provided below of the primary curves and a sample of common ways the names are expressed:

Mid-Columbia
- Mid-C
- MidC
- MIDC

Palo Verde
- PV
- Palo

California Oregon Boarder
- COB
- COB N-S

South Path 15
- SP15
- SP-15
- South of Path 15

North Path 15
- NP15
- NP-15
- North of Path 15

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.

OPUC Data Request 54

Standard Inputs - With regard to the OFPC:

(a) For the Company's initial filing and each TAM update, please indicate the date of the OFPC used.

(b) For the Company's initial filing and each TAM update, please indicate the date/expected of each input to the OFPC. This answer should align with the inputs listed in response to DR 12 section "e."

(c) For the Company's initial filing and each TAM update in Docket Nos. UE 339, UE 356, UE 375, UE 390, and UE 400 please indicate the date of the OFPC used.

(d) For the Company's initial filing and each TAM update in Docket Nos. UE 339, UE 356, UE 375, UE 390, and UE 400 please indicate the date of each input to the OFPC. This answer should align with the inputs listed in response to DR 12 section "e".

Response to OPUC Data Request 54

PacifiCorp objects to this request as outside the scope of this proceeding and not reasonably calculated to lead to the discovery of admissible information. Without waiving the foregoing objection, the Company responds as follows:

The Company clarifies that the reference to "UE-339, UE-356, UE-375, UE-390 and UE-400" is a reference to the following previous transition adjustment mechanism (TAM) filings:

Docket UE-400 – the 2023 TAM (forecast calendar year 2023)
Docket UE-390 – the 2022 TAM (forecast calendar year 2022)
Docket UE-375 – the 2021 TAM (forecast calendar year 2021)
Docket UE-356 – the 2020 TAM (forecast calendar year 2020)
Docket UE-339 – the 2019 TAM (forecast calendar year 2019)

Based on the foregoing clarification, the Company responds as follows:

(a) The date of the official forward price curve (OFPC) used in the Company's initial filing in this 2024 TAM is December 31, 2022. Each TAM update will include the date of the OFPC used and supporting information as part of the work papers provided with each TAM update filing.

(b) It is unclear to the Company what the reference to "align with the inputs listed in response to DR 12 section "e" is intended to be a reference to. This statement does not appear to relate to OPUC Data Request 12 in this proceeding. The Company is therefore unable to address this portion of the request. Based on the foregoing statement, the Company responds as follows:

With regard to the Company's initial filing/direct testimony in this 2024 TAM proceeding, please refer to the Company's response to subpart (a) above.

The July 2023 Update filing is expected to use the Company's June 30, 2023 OFPC. The November 2023 Indicative filing, and the November 2023 Final filing are expected to use prices from within the allowable range (nine days prior to the Indicative filing, and seven days prior to the Final filing).

(c) Please refer to the following information regarding PacifiCorp's OFPCs used in the TAM filings (covering Docket UE-339 through Docket UE-400):

Docket UE 400 – 2023 TAM (forecast year 2023)
Initial filing – filed March 1, 2022 – OFPC date: December 31, 2021
June 2022 Update filing – filed June 22, 2022 – OFPC date: March 30, 2022
Indicative filing – filed November 8, 2022 – OFPC date: November 1, 2022
Final filing – filed November 15, 2022 – OFPC date: November 8, 2022

Docket UE 390 – 2022 TAM (forecast year 2022)
Initial filing – filed April 1, 2021 – OFPC date: December 31, 2020
July 2021 Update filing – filed July 8, 2021 – OFPC date: March 31, 2021
Indicative filing – filed November 8, 2021 – OFPC date: November 1, 2021
Final filing – filed November 15, 2021 – OFPC date: November 8, 2021

Docket UE 375 – 2021 TAM (forecast year 2021)
Initial filing – filed February 14, 2020 – OFPC date: December 31, 2019
June 2020 Update filing – filed June 9, 2020 – OFPC date: March 31, 2020
Indicative filing – filed November 9, 2020 – OFPC date: October 30, 2020
Final filing – filed November 16, 2020 – OFPC date: November 9, 2020

Docket UE 356 – 2020 TAM (forecast year 2020)
Initial filing – filed April 1, 2019 – OFPC date: December 31, 2018
July 2019 Update filing – filed July 15, 2019 – OFPC date: March 29, 2019
Indicative filing – filed November 8, 2019 – OFPC date: October 30, 2019
Final filing – filed November 15, 2019 – OFPC date: November 8, 2019

Docket UE 339 – 2019 TAM (forecast year 2019)
Initial filing – filed March 30, 2018 - OFPC date: December 31, 2017
July 2018 Update filing – filed July 23, 2018 - OFPC date: June 29, 2018
Indicative filing – filed November 8, 2018 - OFPC date: October 30, 2018
Final filing – filed November 15, 2018 - OFPC date: November 8, 2018

(d) It is unclear to the Company what the reference to “align with the inputs listed in response to DR 12 section “e” is intended to be a reference to. This statement does not appear to relate to OPUC Data Request 12 in this proceeding. The Company is therefore unable to address this portion of the request. Based on the foregoing statement, the Company responds as follows:

Please refer to the Company’s response to subpart (c) above. The broker quotes used to produce PacifiCorp’s OFPC on a given date are provided by the brokers on that specific date.

UE 420 / PacifiCorp
June 20, 2023
OPUC Data Request 103

OPUC Data Request 103

General; NPC - See Figure 1 in PAC/100 Mitchell/12. Provide this table with Oregon allocated instead of total company NPC.

(a) What does each of the dots in this chart represent?

(b) Explain the purpose of the chart and the decision to only use Mid-C and Palo Verde.

(c) Produce this same chart with COB, Four Corners, Mead, Mid-C, Mona, NOB, and Palo Verde.

Response to OPUC Data Request 103

PacifiCorp objects to this request as overly broad, unduly burdensome and not reasonably calculated to lead to the discovery of admissible evidence. Without waiving the foregoing objection, PacifiCorp responds as follows:

The Company has not performed the requested analysis. Please refer to Attachment OPUC 103 which provides copies of the Oregon allocated net power costs (NPC) for calendar years 2020 through 2023. The provided information is from Exhibit PAC/101 in each of the Oregon transition adjustment mechanism (TAM) proceedings covering forecast years 2020 through 2022, namely Docket
UE-356 (Wilding), Docket UE-375 (Webb), Docket UE-390 (Webb) and Docket
UE-400 (Wilding). Please refer to the direct testimony of Company witness, Ramon J. Mitchell, Exhibit PAC/101, Mitchell/1 for the Oregon allocated NPC for calendar year 2024.

(a) The dots represent the relationship between the Company's NPC and regional power market prices. Please refer to the non-confidential work papers provided with the Company's response to TAM Support Set 1 (concurrent), specifically non-confidential file "MitchellTestSupp_Table 1_Figure 1_2 NON-CONF.xlsx", worksheet "Figure 1" which shows Figure 1 linked to its supporting data.

(b) The chart is used in the first and second layer "historical actual NPC and the associated trend to regional market prices [and] the extrapolation of the
OFPC" as referenced in the Company's response to OPUC Data Request 101.

The Company operates two balancing authority areas (BAA), PacifiCorp West (PACW) and PacifiCorp East (PACE). Mid-Columbia (Mid-C) is a trading hub representative of PACW, and Palo Verde (PV) is a trading hub representative of PACE.

(c) The Company has not performed the requested analysis.

UE 420 / PacifiCorp
June 20, 2023
OPUC Data Request 109

OPUC Data Request 109

General; NPC - Perform an apples to apples comparison by appropriately including the EIM benefits in each of the cost component categories and provide
an updated confidential table that reflects this calculation and also the accompanying workbook.

Response to OPUC Data Request 109

PacifiCorp objects to this request as overly broad, unduly burdensome, requesting the preparation of a new study or analysis, and not reasonably calculated to lead to the discovery of admissible evidence. Without waiving the foregoing objection, PacifiCorp responds as follows:

The Company has not performed the requested analysis. To appropriately incorporate energy imbalance market (EIM) benefits into each cost/revenue component would require incorporating the fifteen or five minute scheduling/dispatch of the EIM into Aurora's optimization. However, the Company does not have 15-minute or five-minute forecasts of the modeling inputs inclusive of forecasts of 15-minute or five-minute prices that are necessary to attempt such a modeling endeavor.

CASE: UE 420
WITNESS: JULIE JENT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF CONFIDENTIAL EXHIBIT 203

Exhibits in Support
Of Opening Testimony

June 23, 2023

PAC CONF Response to DR 2 Attachment is only available in electronic format.

UE 420 / PacifiCorp
June 6, 2023
OPUC Data Request 48

OPUC Data Request 48

[redacted]

[redacted]

Response to OPUC Data Request 48

[redacted]

[redacted]

[redacted]

[redacted] [redacted]

[redacted]

[redacted]

[redacted] [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

UE 400 / PacifiCorp
May 20, 2022
OPUC Data Request 92

OPUC Data Request 92

CONFIDENTIAL REQUEST - DA/RT - [redacted]

[CONFIDENTIAL BEGINS]

[redacted]

[redacted]

[CONFIDENTIAL ENDS]

Response to OPUC Data Request 92

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

PAC CONF Response to DR 22-2 CONF Attachment is only available in electronic format.

PAC CONF Response to DR 21-1 CONF Attachment is only available in electronic format.

PAC CONF Response to DR 22-1 CONF Attachment is only available in electronic format.

PAC CONF Response to DR 53 CONF Attachment is only available in electronic format.

UE 420 / PacifiCorp
June 20, 2023
OPUC Data Request 104

OPUC Data Request 104

CONFIDENTIAL REQUEST - Backcast/Benchmarking – [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[CONFIDENTIAL ENDS]

Response to OPUC Data Request 104

(a) [redacted]

(b) [redacted]

(c) [redacted]

(d) [redacted]

UE 420 / PacifiCorp
June 20, 2023
OPUC Data Request 105

OPUC Data Request 105

CONFIDENTIAL REQUEST - Backcast/Benchmarking –

[CONFIDENTIAL BEGINS]

[redacted]

[CONFIDENTIAL ENDS]

Response to OPUC Data Request 105

[redacted]

UE 420 / PacifiCorp
June 20, 2023
OPUC Data Request 106

OPUC Data Request 106

CONFIDENTIAL REQUEST - Backcast/Benchmarking –

[CONFIDENTIAL BEGINS]

[redacted]

[CONFIDENTIAL ENDS]

Response to OPUC Data Request 106

[redacted]

UE 420 / PacifiCorp
June 20, 2023
OPUC Data Request 107

OPUC Data Request 107

CONFIDENTIAL REQUEST - Backcast/Benchmarking -

[CONFIDENTIAL BEGINS]

[redacted]

[redacted]

[redacted]

[CONFIDENTIAL ENDS]

Response to OPUC Data Request 107

[redacted]

[redacted]

[redacted]

CASE: UE 420
WITNESSES: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 300
Market Caps, EIM Benefits, Modeling Enhancements

Opening Testimony

June 23, 2023

Q. Please state your business address, names, and occupations.

A. My name is Dr. Curtis Dlouhy, Ph.D. I am an Economist within the Strategy and Integration (SI) Division of the Public Utility Commission of Oregon (Commission or OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/301.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss PacifiCorp's market cap methodology used to forecast off-system sales, its Energy Imbalance Market (EIM) benefits methodology, and the Company's proposed modeling improvements.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared the following exhibits:

- Staff/301 – Witness Qualifications.
- Staff/302 – Responses to Data Requests.
- Staff/303 – Market Cap Methodology Comparison.
- Staff/304 – Western EIM Benefits and Benefits Methodology.

Q. How is your testimony organized?

A. My testimony is organized as follows:

SUMMARY OF FINDINGS AND RECOMMENDATIONS

Q. Please summarize your findings and recommendations on market caps.

A. I recommend that the Company return to using the "third quartile of averages" method to forecast market caps. I, along with Staff Witnesses Anna Kim and Julie Jent, make this recommendation as a way to holistically address off-system sales revenue by reconciling the under-forecast of revenue resulting from the Day-Ahead/Real-Time (DA/RT) adder persistently brought up by Staff and stakeholders, and the Company's perceived over-forecast of revenues resulting from the "third quartile of averages" approach that Staff has recommended in the past two TAM proceedings. Implementing the "third quartile of averages" approach reduces Oregon-allocated NVPC by $5.69 million.

Q. Please summarize your findings and recommendations on the Company's EIM benefits forecast.

A. I recommend that no changes be made to the Company's EIM transfer or greenhouse gas (GHG) benefits forecasts at this time. However, I note that the model fit for parts of the Company's transfer benefits model are getting worse and hope to continue exploring a possible refinement during this proceeding.

Q. Please summarize your findings and recommendations on the Company's proposed modeling improvements.

A. I do not oppose the Company's proposal to remove the trapped energy adjustment at this time.

ISSUE 1. MARKET CAP METHODOLOGY

Q. What are market caps used for in PacifiCorp's TAM proceedings?

A. PacifiCorp's market caps are used to aid the Company when forecasting its off-system sales. In past years, the Company has attested that the previous model it used to forecast power costs, GRID, would assume unlimited market depth and thus forecast economic sales that it could not make during its actual operation. The Company stated in the 2023 TAM that this problem persists even in AURORA.[1] Without agreeing on the methodology, parties agreed to allow the Company to use the "average of averages" approach among other modeling adjustments in UE 400 as part of the stipulation adopted in Order No. 22-389.

Q. Please provide a brief history of the market cap methodology PacifiCorp has used in its TAM proceedings prior to this filing.

A. In UE 245, the 2013 TAM, the Company proposed capping its off-system sales to its major trading hubs to offset the forecasting problem caused by GRID shortcomings identified by the Company, namely the unlimited market depth issue. This proposal was intended to make permanent the non-precedential method the Company used to forecast off-system sales in the 2012 TAM.[2] The Company's proposed fix to this perceived continued forecasting error was to impose a technique called the "average of averages" method, wherein market caps are calculated to limit off-system sales. The "average of averages"

[1] UE 400, PAC/100, Wilding/28.
[2] *In re PacifiCorp*, OPUC Docket No. UE 245, Order No. 12-409 at 4 (Oct. 29, 2012).

method works by averaging the last four years of average monthly capacities at each hub differentiated by on- and off-peak hours.

Staff opposed this change in the 2013 TAM and noted that PacifiCorp's proposed method to address off-system sales imposed a market restriction that did not actually exist and incorrectly cut off sales with positive margins.[3] To balance the concerns held by Staff and the Company, Staff proposed that the Commission adopt the "maximum of averages" method, wherein the market caps are calculated by finding the *maximum* of the last four years of average monthly capacities at each hub differentiated by on- and off-peak hours. In practice, both methods create 24 separate market caps for each of PacifiCorp's hubs. In Order No. 12-409, the Commission adopted Staff's recommended "maximum of averages" approach, explaining that the "maximum of averages" approach was meant to effectively split the difference between the Company's proposed method and Staff's preferred method of removing market caps entirely.[4]

In UE 390 – the 2022 TAM – PacifiCorp proposed that it be allowed to use the "average of averages" method it initially proposed in UE 245, noting that GRID still had a history of over-forecasting off-system sales even under the "maximum of averages" method. Staff opposed this change in UE 390, noting that the Company did not provide sufficient evidence that the move to the "average of averages" method would bring the Company's NPC forecast

3 *In re PacifiCorp*, OPUC Docket No. UE 245, Order No. 12-409 at 5 (Oct. 29, 2012).
4 *In re PacifiCorp*, OPUC Docket No. UE 245, Order No. 12-409 at 7-8 (Oct. 29, 2012).

closer to reality.[5] Staff also argued that permanent changes to the Company's forecasting methodology in the year before it switches to AURORA – a much more sophisticated energy forecasting software than GRID – were inappropriate.

In place of the Company's proposed "average of averages" method, Staff recommended adopting the "third quartile of averages" method on a non-precedential basis until AURORA was implemented.[6] In this method, the Company would calculate its market caps by finding the *average of the two highest values* in the last four years of average monthly capacities at each hub differentiated by on- and off-peak hours. This recommendation was meant to balance Staff's desire to have a model that adequately mimics market realities while mitigating some of the Company's perceived over-forecasting problem. The Commission adopted Staff's recommendation on a non-precedential basis in Order No. 21-379.[7]

In the 2023 TAM, UE 400, the Company again proposed that the "average of averages" method be used to forecast off-system sales, which was opposed by both Staff and stakeholders in their opening testimonies.[8,9,10] Staff recommended that the Company continue to use the "third quartile of averages" approach used in the 2022 TAM in opening testimony.[11] Ultimately,

5 *In re PacifiCorp*, OPUC Docket No. UE 390, Order No. 21-379 at 26 (Nov. 1, 2021).
6 *Id.*
7 *In re PacifiCorp*, OPUC Docket No. UE 390, Order No. 21-379 at 28 (Nov. 1, 2021).
8 UE 400, Staff/300, Dlouhy/2.
9 UE 400, AWEC/100, Mullins/14.
10 UE 400, CUB/100, Jenks/7.
11 UE 400, Staff/300, Dlouhy/2.

parties allowed for the use of the “average of averages” approach in the 2023 TAM without agreeing with the methodology as part of the adopted stipulation.

Q. Does PacifiCorp propose to modify its method to calculate market caps in the 2024 TAM?

A. No. The Company still proposes to use the “average of averages” approach for the 2024 TAM.

Q. Do you agree with the Company’s intention to use the “average of averages” approach even after its switch to AURORA?

A. No. I recommend that the Company adopt the “third quartile of averages” approach used on a non-precedential basis in the 2022 TAM.

Q. Why do you recommend that the Company use the “third quartile of averages” approach?

A. I recommend that the “third quartile of averages” approach be used both for many of the same reasons that were brought up by Staff in UE 400 and as a way to solve another recurring TAM issue holistically. In particular:

1. The “third quartile of averages” approach better aligns with the operational realities of transacting on the open market, as the Company does not actually face any true market capacity limits at any of its wholesale hubs.
2. There is still insufficient evidence to show that the “average of averages” approach produces a more accurate forecast than the “third quartile of averages” approach in AURORA.

3. Even if the "third quartile of averages" method does overforecast off-system sales, the reduction to NVPC by this overforecast effectively offsets the increase to NVPC from the Day-Ahead/Real-Time (DA/RT) adder. Given that both of these items are ad hoc augmentations to off-system sales, Staff believes that considering their net effect to NVPC is appropriate.

Q. Regarding your first point, please explain why the "third quartile of averages" approach better aligns with operational realities.

A. As described previously in this testimony, market caps are essentially an ad hoc workaround to ensure that AURORA or GRID does not forecast more power sales into market hubs than it actually does in reality. The Company does so by creating a cap on the total power that can actually be sold to these market hubs. In reality though, there is no true cap to the amount of energy that the Company can sell to or buy from the market hubs. In fact, as the names of the two prevailing methods of creating market caps imply – "third quartile of averages" and "average of averages" – the Company often sells far more power into these markets than the market caps allow.

Much like the previous two TAMs in UE 390 and UE 400, Staff still holds the belief that the Company's modeling practices should match operational realities to the extent practicable.[12] In holding this belief however, Staff recognizes that no modeling method is perfect, and some ad hoc adjustment may be needed. With this balance in mind, Staff recommends that the

[12] UE 400, Staff/300, Dlouhy/2.

Commission adopt the "third quartile of averages" approach for the purposes of forecasting power costs in the TAM.

Q. Regarding your second point, why do you believe that there is still insufficient evidence to determine whether the "third quartile of averages" or "average of averages" approach is better to forecast off-system sales?

A. In Oregon, AURORA has only been used to forecast power costs since the 2023 TAM, meaning that actual off-system sales can only be matched up to less than six months of forecasted data as of the publication of this testimony. While something may be learned from this limited comparison, Staff believes that power costs should be viewed on an annual basis in order to better smooth out any expected fluctuations related to seasonal trends or pure randomness.

Q. Are there other ways that Staff may be able to verify the accuracy of these two methods?

A. Perhaps, but evidence would still be very limited. The Company has used the "average of averages" approach to forecast off-system sales using AURORA in the Company's Energy Cost Adjustment Clause (ECAC) in California and Power Cost Only Rate Case (PCORC) in Washington in their 2022 forecast of power costs. In the 2023 TAM, Staff requested these forecasted values using both the "average of averages" approach and the "third quartile of averages" approach.

Unfortunately, the results of these AURORA model runs were confidential in the previous TAM proceeding. Staff has issued a data request to compare these values to actual off-system sales in this proceeding, but the response is not due until after the publication of opening testimony. Staff intends to analyze the comparison between forecasted and actual off-system sales more fully in the next round of testimony. Regardless of what this analysis shows, it is worth reiterating that this would give merely a single comparison year.

Q. Regarding your third point, what do you mean that the "third quartile of averages" approach can offset the NVPC effects of the DA/RT adjustment?

A. Staff and stakeholders have long lamented the structure of the DA/RT adjustment for various reasons. Chief among them, Staff and stakeholders have in the past noted that the DA/RT adjustment 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.[13] The result of this is that the DA/RT creates "artificial losses" to the model that inflate NVPC. See the testimony of Staff Witness Julie Jent for a more thorough description of the DA/RT methodology and its effect on NVPC in this proceeding.[14]

Conversely, in the previous two TAM proceedings the Company contended that the "third quartile of averages" method and its predecessor – the "maximum of averages" method – over-forecast off-system sales and thus

[13] UE/400, Staff/200, Cohen/9.
[14] Staff/200.

under-forecast NVPC. Even though Staff still believes that there is scant evidence to show that this is true of the "third quartile of averages" method, Staff believes that reinstituting the "third quartile of averages" approach – when paired with the current DA/RT adder – will lead to a more reasonable estimate of holistic off-system sales revenue.

Q. Why do you believe that it is appropriate to think of the DA/RT adjustment together with the market cap methodology holistically?

A. These two seemingly different items should be viewed holistically because both items are augmentations to total NVPC via adjustments to market hub activity. In fact, when comparing actual off-system sales to off-system sales forecasted using market caps, parties have netted out augmentations due to book-outs and the DA/RT.[15] With this in mind, Staff believes it to be intuitive that these two adjustments should be viewed together rather than analyzing them individually.

Q. How do you calculate the NVPC effects of reinstituting the "third quartile of averages" approach?

A. I calculated my adjustment by first recalculating what the market caps would be if the Company used the "third quartile of averages" method. Once these new market caps were found, Staff plugged the new market caps into AURORA while keeping all other inputs for the Company's base 2024 NVPC run identical to the Company's initial filing. My adjustment reflects the difference in NVPC

[15] UE 400, AWEC/100, Mullins/16.

between the AURORA model run with the "third quartile of averages" approach and the "average of averages" approach.

Q. What is the difference in market caps between the "maximum of averages" approach and the "third quartile of averages" approach?

A. Confidential Table 1 contains the average difference between these approaches for each of the Company's six hubs. It is worth restating that each approach requires a different market cap be calculated for each hub-month-HLH/LLH combination, meaning that each entry in this table is the average of 24 different market caps that were ultimately plugged into AURORA. A full breakdown of the "average of averages" market caps and the "third quartile of averages" market caps can be found in confidential exhibit 303.[16]

Table 1

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

16 Staff/303, Dlouhy/1.

Q. What is the change to NVPC when you implement the "third quartile of averages" approach?

A. Implementing the "third quartile of averages" approach decreases the Company's forecasted NVPC by $19.64 million systemwide or $5.69 million on an Oregon-allocated basis. I include the workpaper containing the calculation of this adjustment electronically.

Q. What is your overall recommendation regarding market caps?

A. I recommend that the Commission require the Company to use the "third quartile of averages" method to forecast off-system sales in the TAM. Staff makes this recommendation as a holistic way to more accurately forecast the Company's NVPC.

Implementing this change in the 2024 TAM reduces NVPC by $19.64 million systemwide, or $5.69 million on an Oregon-allocated basis.

ISSUE 2. EIM BENEFITS MODELING

Q. What is the Western Energy Imbalance Market (EIM)?

A. The Western EIM is a voluntary real-time market managed by the California Independent System Operator (CAISO). It began in 2014 as a bilateral market between CAISO and PacifiCorp, but has since grown to include nineteen entities, including all three Oregon-regulated electric utilities. To participate in the Western EIM, entities bid in the cost to dispatch their generators and must also prove that they have sufficient capacity to serve their own needs. After entities have all bid into the Western EIM, the lowest-cost resources are selected to serve load and generators are compensated at the transfer locational marginal price (LMP) by entities that demand power at five-minute intervals.

As of May 31, 2023, CAISO claims that the Western EIM has saved members a cumulative $3.8 billion, with over $600 million of that going directly to PacifiCorp.[17]

Q. How does the Western EIM calculate these benefits?

A. These benefits that comprise the $3.8 billion total are not merely a simple summation of revenue earned by transacting in the Western EIM. Instead, the benefits are comprised largely of three distinct parts that PacifiCorp forecasts separately:

17 Staff/304, Dlouhy/1.

1. Transfer benefit, which is calculated by determining a counterfactual dispatch cost that would have occurred if the Western EIM was not in place to re-dispatch its members generators economically.
2. Greenhouse Gas (GHG) Benefit, which is calculated by finding the Company's revenue earned through EIM less any compliance costs associated with the California Air Resources Board (CARB).
3. Flex reserve benefit, which is measured as the reduction in MW to the Company's reserve requirement as a result of participating in the EIM.

CAISO presents benefits for each member at the end of each quarter. A full description of CAISO backwards-looking benefits calculation methodology can be found in Staff Exhibit 304.[18]

Q. Does the Company use the same method to calculate its benefit from participating in the Western EIM?

A. No, the Company employs a slightly different method that Staff has not previously taken issue with. While CAISO presents the Western EIM benefits retroactively, the Company has historically forecasted its EIM benefits on a forward-looking basis in three parts: namely the transfer benefit, the GHG benefit, and the wheeling benefit.

[18] Staff/304, Dlouhy/3.

Q. What component of the total forecasted EIM benefit are you addressing in this section?

A. My testimony addresses the regression model used to forecast energy transfer benefits and the Company's method to forecast the EIM GHG benefits. I will begin by discussing the Company's forecasted EIM transfer benefit and finish with a short analysis of its forecasted GHG benefit.

Q. Has Staff analyzed the Company's EIM transfer benefits forecasting methodology in previous TAM proceedings?

A. Yes. Staff has also discussed this issue in the previous three TAM proceedings. In the 2022 and 2023 TAM, Staff recommended changes to part of the Company's forecasting model that were ultimately adopted by the Company.

Q. How do utilities accrue EIM energy transfer benefits?

A. A utility can accrue EIM energy transfer benefits in two ways:

1. Buying power from other members that it would otherwise have to generate at a higher cost.
2. Selling power economically to other members that it would not be able to sell otherwise.

Q. How does the Company calculate forecast energy transfer benefits?

A. As described more fully below, the Company uses an econometric model based on market fundamentals to calculate forecast energy transfer benefits. Historic energy transfer benefits inform the Company's regression model for forecasting future energy transfer benefits.

Q. Please describe the market fundamentals model that the Company uses to calculate EIM transfer benefits in the 2023 TAM.

A. PacifiCorp's econometric model is based on four separate regressions estimated using Ordinary Least Squares (OLS) with standard error corrections whose results are used to forecast the total energy transfer benefit for a calendar year. The four regressions used to calculate the energy transfer benefits derived from:

- PACE Exports,
- PACE Imports,
- PACW Exports, and
- PACW Imports.

The regressions are estimated using monthly data on historic energy transfer benefits and market characteristics from January 2015 through December 2022, with the exception of the PACE Import model whose data begin in December 2015.

Q. Have the regressions changed since the conclusion of the 2023 TAM?

A. No. In the 2023 TAM, I testified that the PACW regression contained some variable transformations that were outside econometric norms. In particular, this model relied on taking the square root of the price data in lieu of the natural log, which was used for the other three models and is much more accepted in econometric modelling. I recommended changes to the PACW Exports model to incorporate natural logs instead of square roots in order to improve the model fit and better align with the norms of econometric modelling.

Q. Did the Company accept your change to the PACW Export model?

A. Yes. The Company accepted that change for the 2023 TAM and continues to use it in the 2024 TAM based on my inspection of the Company's response to Staff DR 70.[19] As it stands, the Company estimates the following set of regressions to forecast its EIM transfer benefits in its initial filing:

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. What is the Company's total EIM transfer benefit for the 2024 TAM?

A. According to workpapers and the code provided by the Company in its initial response to Staff DR 70, the total forecasted EIM transfer benefit is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** system wide, or **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** on an Oregon-allocated basis.

[19] Staff/302, Dlouhy/1.

Q. Do you recommend changes be made to the regression models the Company uses to forecast EIM transfer benefits for the 2024 TAM?

A. Not at the moment. In the previous two TAM proceedings, I have made suggested changes to the PACE Exports and PACW Exports models based both on the model fit and underlying econometric principles. I have no suggested changes to the models based on underlying econometric principles at this time.

However, it is worth pointing out that the Company's PACE Imports model continues to have poor model fit. While I believe that there is value in maintaining a consistent methodology between proceedings based on econometric fundamentals and simple methodology where possible, I think the continued poor performance of the PACE Imports model is a cause for concern moving forward.

Q. How does the model fit for the PACE Imports model compare to the other three models?

A. Confidential Table 2 contains the adjusted R-squared for each of the four models. The adjusted R-squared varies between 0 and 1, with higher values indicating better model fit. Unlike the standard R-squared metric, the adjusted R-squared penalizes models with the penalty increasing as the number of variables increase, which in practice helps quantify possible overfitting concerns in a more digestible manner than other, more nuanced information criteria. It can be clearly seen that the model fit for the PACE Imports model is significantly worse than the other three models.

Table 2

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. Why do you not suggest any changes to the PACE Imports model at this time?

A. The TAM proceeding moves quickly, and I did not have adequate time to explore other modeling choices in the short time between the Company's response to Staff DR 70 and the filing date for opening testimony in this proceeding. As this case progresses, I intend to investigate possible improvements to the PACE Imports model. However, I view the overall forecast of transfer benefits to be reasonable at this time.

Q. Turning now to the Company's EIM GHG forecast, how large is the Company's forecasted EIM GHG benefit for the 2024 TAM?

A. PacifiCorp EIM GHG benefit for the 2024 TAM is forecasted to be approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL],** which constitutes a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** from the GHG benefits present in the 2023 TAM.

Q. Do you have any adjustments to the EIM GHG benefits forecast?

A. Not at this time. In past TAM proceedings Staff had advocated that the GHG benefits be scaled upwards to reflect the growth in California Carbon Allowance prices. In the Company's reply testimony in UE 400, the Company agreed with Staff's recommendation and integrated this change. This change appears to have been carried forward by PacifiCorp into this proceeding as well. While Staff is still monitoring this issue, Staff finds no reason at the moment to recommend further changes.

Q. Do you have any adjustments to either of these two portions of the Company's EIM benefits forecast?

A. Not at this time. As I mentioned previously, Staff is interested in further analyzing the Company's modeling choices for the PACE Exports model with the hopes that the model fit can be improved. On the off chance that an improvement is found, Staff will introduce this change in the next round of testimony.

ISSUE 3. MODELING IMPROVEMENTS

Q. What modeling improvements does the Company propose in this filing?

A. Apart from implementing the modeling improvements agreed to at the end of the previous TAM docket, the Company proposes to eliminate the trapped energy adjustment moving forward.[20] In place of the trapped energy adjustment, the Company proposes to allow AURORA to realistically curtail wind production, which would result in an increase in systemwide NVPC of $14 million and $4.1 million on an Oregon-allocated basis.[21]

Q. What is the trapped energy adjustment and why was it used in past TAM proceedings?

A. As the Company describes in its opening testimony, the trapped energy adjustment was a modeling construct used to aid the Company's legacy modeling software, GRID, in valuing the excess supply of energy that cannot actually be delivered to load zones.[22] In particular, the Company notes that the production tax credits (PTCs) associated with wind production often created a negative dispatch price, which was not possible in GRID and caused problems with the resource stack. As a workaround, these wind assets were modeled as must-run resources whose load is funneled into "trapped energy zones" and

[20] PAC/100, Mitchell/24.
[21] PAC/100, Mitchell/26.
[22] PAC/100, Mitchell/25.

whose energy was valued at 25 percent of the market price in the 2023 TAM.[23] The Company stated that this led to an overstatement of sales revenue.

Q. Does AURORA have the capability to allow for the negative prices and curtailment that was absent in GRID?

A. According to the Company's opening testimony, AURORA is capable of integrating curtailment and negative prices for the Company's wind assets. In lieu of creating trapped energy zones, the Company proposes to simply let AURORA curtail its wind assets based on modeled transmission constraints.

Q. Does Staff oppose this adjustment?

A. Not at this time, but Staff would like to see intervenors' testimony on the issue before fully supporting this adjustment. Staff has in the past recognized that the trapped energy adjustment was a modeling concept to get around transmission constraints that GRID was unable to consider.[24] Given that AURORA is able to now model transmission constraints and can curtail in response to these constraints, I do not see a reason to continue to model trapped energy zones at this time.

Q. Does this conclude your testimony?

A. Yes.

---

23 PAC/100, Mitchell/25-26.
24 UE 400, Staff/200, Cohen/3.

CASE: UE 420
WITNESS: Curtis Dlouhy

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 301

Witness Qualifications Statement

June 23, 2023

WITNESS QUALIFICATION STATEMENT

NAME:	Curtis Dlouhy
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Economist, Strategy and Integration Division
ADDRESS:	201 High St. SE, Ste. 100 Salem, OR 97301-3612
EDUCATION:	PhD, Economics University of Oregon, Eugene, OR Master of Science, Economics University of Oregon, Eugene, OR Bachelor of Arts, Economics & Math Nebraska Wesleyan University, Lincoln, NE
EXPERIENCE:	I have been employed by the Oregon Public Utility Commission (OPUC) in the Strategy and Integration Division since April 2022 and had previously worked in the Rates, Finance, and Audit Division since June 2020. My responsibilities include providing research, analysis, and recommendations on a range of regulatory issues. I have provided analysis and expert testimony in various contested cases including UG 388, UG 389, UG 390, UE 374, UE 390, UE 391, UE 394, UG 433, UG 435, UE 399, UE 400, UE 402, UE 416 (Ongoing), and UE 420 (Ongoing). Prior to working for the Commission, I was employed by the University of Oregon as a graduate employee where I taught classes in Intermediate Microeconomics, Industrial Organization, and Antitrust Economics. My PhD dissertation won an award from the Transportation and Public Utility Working Group and covered topics in fossil fuel markets ranging from coal mine closure, dispatchable electricity choices under carbon taxes and coal transport via railroad. While completing my PhD, I provided economic analysis for the Graduate Teaching Fellows Federation as a member of its contract bargaining team.

CASE: UE 420
WITNESS: Curtis Dlouhy

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 302

Responses to Data Requests in Support Of Opening Testimony

June 23, 2023

UE 420 / PacifiCorp
June 7, 2023
OPUC Data Request 70

OPUC Data Request 70

General - Refer to PAC/100, Mitchell/7 at lines 1-10. Please provide the code and data used to estimate the EIM inter-regional transfer benefits.

Response to OPUC Data Request 70

Please refer to Confidential Attachment OPUC 70.

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.

CASE: UE 420
WITNESS: Curtis Dlouhy

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 303

Market Cap Methodology Comparison

June 23, 2023

[redacted]

CASE: UE 420
WITNESS: Curtis Dlouhy

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 304

Western EIM Benefits and Benefits Methodology

June 23, 2023

WESTERN ENERGY IMBALANCE MARKET

Search

Benefits

$3.82 billion in gross benefits since Nov 2014 *(as of 5/31/2023)*

(millions $)

WEIM PARTICIPANTS	2014-2019	2020	2021	2022	2023 Q1	TOT
Arizona Public Service Entered 10/2016	$140.32	$48.96	$58.79	$88.84	$26.43	$36
Avista Utilities Entered 04/2022				$24.08	$6.38	$30
BANC Entered 04/2019	$15.86	$30.36	$129.61	$281.65	$44.63	$50
BPA Entered 05/2022				$26.39	$11.83	$38
California ISO Entered 11/2014	$191.88	$62.04	$146.00	$289.83	$67.86	$75
Idaho Power Company Entered 04/2018	$55.11	$26.30	$52.62	$43.95	$13.31	$19
LADWP Entered 04/2021			$42.71	$75.09	$27.99	$11
NV Energy Entered 12/2015	$89.03	$24.62	$47.76	$117.75	$47.19	$32
NorthWestern Energy Entered 06/2021			$12.09	$31.22	$12.60	$55
PacifiCorp Entered 11/2014	$235.29	$40.63	$115.46	$200.02	$28.94	620
Portland General Electric Entered 10/2017	$73.27	$31.76	$30.78	$61.26	$21.67	$21
Powerex Entered 04/2018	$19.78	$4.03	$3.08	$12.41	$16.80	$56
PNM Entered 04/2021			$12.53	$34.59	$22.40	$69
Puget Sound Energy Entered 10/2016	$41.25	$13.68	$20.67	$31.15	$15.28	$12
Salt River Project Entered 04/2020		$36.06	$47.90	$77.08	$31.38	$19
Seattle City Light		$6.64	$13.92	$14.88	$4.20	$39

Entered 04/2020		$6.64	$13.92	$14.88	[illegible]	$39
Tacoma Power Entered 04/2022				$9.61	$6.55	$16
TEP Entered 05/2022				$40.93	$10.37	$51
TID Entered 04/2021			$5.11	$10.82	$3.01	$18
TOTAL	$861.79	$325.08	$739.03	$1471.55	$418.82	**$381**

Quarterly benefits

These reports quantify the estimated gross benefits from Western Energy Imbalance Market (WEIM) operations.

- ISO Western Energy Imbalance Market Benefits Report Q1 2023 5/31/2023 10:00
- ISO Western Energy Imbalance Market Benefits Report Q4 2022 1/31/2023 09:52

2014 – 2022 reports

ISO greenhouse gas emissions tracking reports

An accounting of GHG emissions for th balancing authority area

WEIM benefit methodology

OASIS | MPP | WEIM Portal | Developer | Glossary | Sitemap | Privacy | Terms of use

EIM Quarterly Benefit Report Methodology

Effective with Q1 2021 EIM benefits report

Prior to the creation of this document, the methodology for the benefits calculation was posted in a technical bulletin and in the benefit report itself. This document consolidates these prior materials into a concise paper for easier understanding of how the EIM benefits are calculated.

The total EIM benefit is the cost saving of the EIM dispatch compared with a counterfactual (CF) without EIM dispatch. The counterfactual dispatch meets the same amount of real-time load imbalance in each BAA without EIM transfers between neighboring EIM BAAs. For an EIM BAA, the benefit can take the form of cost savings or profit or their combination. A BAA will be likely to have energy cost savings when the BAA is importing energy economically, or its base schedules are being optimized by the EIM. To the extent an entity base schedule is optimized prior its submission into the EIM, the benefits may be lessened when compared to an entity that has not submitted optimized base schedules into the EIM. A BAA will be likely to have an energy profit when the BAA is exporting energy economically to other BAAs and being paid a price higher than the bid cost. A BAA other than the ISO may also have a GHG profit when the resource is allocated GHG MWs and is receiving GHG revenue based on marginal GHG cost that is likely higher than its own GHG bid cost.

For each 5-minute interval, the **EIM benefit for a BAA = counterfactual dispatch cost – (EIM dispatch cost + transfer cost + flex ramp transfer cost) + GHG revenue – GHG cost.** The 5-minute level EIM benefits are then aggregated each month with a multiplier 1/12 to convert ($/5 min) to a dollar amount.

EIM Benefit Calculation Components

EIM Dispatch Cost

The total dispatch cost for a BAA for an interval is the sum of all the unit level EIM dispatch costs for that BAA for that interval.

For all BAAs other than CAISO, the dispatch cost only includes variable dispatch cost, i.e. the bids submitted by the corresponding Scheduling Coordinator.

For the ISO’s long start units, we only consider variable dispatch cost. For the ISO’s short start units, we use a generic cost formula, which includes variable dispatch cost, no load cost, and startup cost. Specifically, the three-part cost for short start units includes:

- The variable dispatch cost of RTD, which is equal to the bid cost associated with the delta instruction above or below the base schedule for each interval,
- the no load cost associated with the incremental dispatch, which is equal to the no load cost divided by Pmax, then multiplied by the delta instruction from the base schedule,
- The startup cost associated with the incremental dispatch, which is equal to the startup cost divided by the minimum online hours, then multiplied by the delta instruction from base schedule divided by the Pmax.

The purpose of this generic cost formula is to evaluate cost differences between EIM dispatches and counterfactual dispatches without performing sophisticated unit commitment simulations. Prior to Q1 2016, only variable dispatch cost was considered in the EIM benefit calculation. With NV Energy joining EIM and improving the transfer capabilities from and to the ISO, we observed a significantly increased transfer volume in EIM. The higher transfer volume cannot be sufficiently replaced by resources online in EIM without committing or de-committing resources, and hence the ISO adopted a three-part cost formula as of Q1 2016 to allow for unit commitment decisions to better evaluate the production difference between EIM and the counterfactual dispatch of the ISO. The unit commitment decisions were made only for short start units that were not combined cycle units. The combined cycle units have complicated models in EIM, so their counterfactual commitment status is fixed at the EIM commitment status to avoid oversimplification.

We approximate the ISO's commitment costs by converting the startup cost and no load cost into variable dispatch cost, assuming a committed short start resource will be fully loaded for minimum online hours. For each supply segment, the corresponding three-part variable cost is equal to

bid_price + no_load_cost/Pmax + startup_cost/min_up_hour/Pmax

Note the formula above converts startup cost (in unit $) and no load cost (in unit $/h) into variable dispatch cost (in unit $/MWh). By doing this, the commitment for the ISO's short start units can be determined based on the economic metric order of the three-part variable cost.

Transfer Cost

As a convention, select the importing direction as the default direction for a transfer, so the importing transfer is positive and the exporting transfer is negative. The transfer cost is equal to the transfer MW times the transfer price. For transfers involving the ISO in either the importing direction or the exporting direction, the transfer price is the other BAA's LMP plus the shadow price of the transfer. In doing this, the congestion rent on the transfer will be fully attributed to the other BAA. For transfers involving two BAAs that are not the ISO, the transfer price will split the congestion shadow price on the transfer in half. For an importing BAA, the transfer price is the LMP of the BAA minus half of the absolute value of the transfer shadow price. For an exporting BAA, the transfer price is the LMP of the BAA plus half of the absolute value of the transfer shadow price. The transfer could occur in both the 15-minute market and the 5-minute market. In this case, the transfer cost is 15-minute transfer * 15-minute transfer price + (5-minute transfer – 15-minute transfer) * 5-minute transfer price for each 5-minute interval.

For the prices (LMPs) used in the EIM benefits, the calculation uses the corresponding ELAP prices of each EIM area. For CAISO prices, the calculation uses the prices associated at the corresponding scheduling points at the Malin, Palo Verde, El Dorado or Rancho Seco interties. The specific scheduling price to be used among these intertie locations is in relationship to the benefit calculated to a specific EIM area. For instance, when calculating the benefits between PAC West and CAISO, the calculation will use Malin scheduling point price (CAISO side).

Flex Ramp Transfer Cost

In 2016, the ISO implemented the flexible ramping products to replace flexible ramping constraints. The flexible ramping products are available capacities to handle future load and generation uncertainties, and include both the upward ramping capacity and downward ramping capacity. They may be put aside in RTD to enhance dispatch flexibility. One BAA's flexible ramping capacities in RTD may be helping other BAAs. In this case, the BAA that exports flexible ramping products should receive payment from other BAAs to compensate the dispatch cost of keeping flexible ramping capacities, and the BAA that imports flexible ramping products should pay other BAAs to reflect its dispatch cost to handle future uncertainties. This is similar to how energy transfer is treated in the EIM benefit calculation. Energy transfer is explicitly modeled in EIM, while flexible ramping transfer is not. We need to calculate a BAA's flexible ramping transfer. First, we allocate the system flex ramp award to each BAA in proportion to its individual BAA requirement. Then we calculate the flex ramp transfer as the BAA's RTD flexible ramping award minus its allocated share. The flex ramp transfer cost is equal to the flex ramp transfer multiplied by the EIM whole footprint flex ramp shadow price.

Counterfactual Dispatch Cost

The counterfactual dispatch for an EIM BAA mimics the market operations without importing or exporting through the EIM transfers. The counterfactual dispatch moves units inside the BAA to meet the same real-time load imbalance as the EIM dispatch based on economic merit order without considering transmission constraints. For PacifiCorp, the transfer limit between PACE and PACW is enforced in the counterfactual dispatch.

Neglecting transmission constraints in a BAA tends to underestimate the EIM benefit. The magnitude depends on how significant the congestion is. Severe congestion impacting EIM benefits was not observed until October 2017, where transmission congestion happened between the generation in Wyoming and PACE's load in PacifiCorp. The impact of this congestion to the EIM benefit calculation can be demonstrated with the following example.

Assume in PACE, load increased 10 MW from the base schedule, generation decreased 100 MW from the base schedule, and PACE imported 110 MW in EIM. Note that energy is balanced in PACE with 110 MW of transfer import replacing 100 MW of generation and serving 10 MW of load above the base schedule. Assume the decremented generation cost is $20/MWh, and the import cost is $120/MWh. From an economic standpoint, the EIM dispatched the resources out-of-merit with high cost supply being incremented and low cost supply being decremented. If we were to calculate the EIM benefit ignoring the congestion effect, the benefit will be negative. The calculation is as follows:

> EIM dispatch cost = -100 MW * $20 = –$2,000.
>
> EIM transfer cost = 110 MW * $120 = $13,200.
>
> Counterfactual dispatch cost = 10 MW * $20 = $200.
>
> For simplicity, ignore flex ramp and GHG. The EIM benefit is calculated as $200 – (–$2,000 + $13,200) = –$11,000.

To better understand the root cause of the negative benefit, we break the calculated benefit into two components: infeasible base schedule and infeasible counterfactual.

1. Infeasible base schedule: In the EIM, the imported $120 transfer replaced 100 MW of $20 internal generation, and produced a negative benefit equal to 100*($20-$120) = -$10,000. The extra dispatch cost in EIM is not due to economics, but due to infeasible base schedules for certain constraints, which forces the EIM to mitigate congestion, and incurs additional cost. For this reason, we need to add the congestion management cost to the counterfactual dispatch cost to reflect the need to perform the same congestion management dispatch as in the EIM. In the example, we add $10,000 to the counterfactual dispatch cost.

2. Infeasible counterfactual: In the counterfactual, the merit order dispatch did not know that dispatching up the $20 generation would overload the transmission, and produced a negative benefit equal to 10*($20-$120) = -$1,000. The counterfactual should recognize the economic $20 supply is subject to transmission congestion, and cannot be dispatched. Therefore, in the counterfactual dispatch, for increased net load, we dispatch only supply offers with a bid price >= the transfer LMP. For decreased net load, we dispatch down only supply offers with a bid price <= the transfer LMP. In the example, the net load is 10 MW, so we only dispatch resources that bid above $120, assume these supplies cost $125/MWh.

With these two enhancements, we revise the benefit calculation as follows:

EIM dispatch cost = -100 MW * $20 = –$2,000.

EIM transfer cost = 110 MW * $120 = $13,200.

Counterfactual dispatch cost = 10 MW * $125 + $10,000 = $11,250.

The new EIM benefit is calculated to be $11,250 – (–$2,000 + $13,200) = $50.

These enhancements only apply when we detect significant congestion indicated by the LMP difference between the BA's ELAP and DGAP greater than a tolerance setting. Currently, the tolerance is set to $5/MWh.

The counterfactual dispatch makes unit commitment decisions only for the ISO's short start units. The unit commitment decisions are based on the generic three-part variable cost formula, which has converted startup cost and no load cost into variable dispatch cost, so unit commitment can be determined by the economic metric order of the three-part cost.

Prior to the 2016 Q4 report, we used the resources' RTD dispatching limits from the EIM in the counterfactual. The EIM dispatching limits are 10-minute ramp limited in RTD, and they may be overly constraining for the counterfactual theoretically. The counterfactual will replace the transfers with internal dispatches, but it does not need to do it within 10-minute timeframe. When EIM transfer volumes are moderate relative to the EIM dispatching range, this limitation may not be a real problem, because the EIM dispatch range is mostly sufficient to replace the transfers. As the EIM footprint increases, the transfer volume between BAAs also increases. We observed that some EIM transfers exceeded 1,000 MW frequently. The EIM dispatching range started to show its limitation. In Q4 of 2016, we expanded the resources' dispatching range to base schedule and FMM dispatching limits. From Q2 of 2017, we decided not to use EIM calculated limits. Instead, the dispatching range is constructed based on the resource's economic bid range in the following way:

a) Start with the resource's bid range [bid_MW_min, bid_MW_max]
b) Block the ancillary service provisions, so the new range is [bid_MW_min+reg_down, bid_MW_max – reg_up – spin – nonspin]
c) If the resource is a wind or solar resource, limit its upper limit by the forecasted output, so the new range is [bid_MW_min+reg_down, min(bid_MW_max – reg_up – spin – nonspin, wind or solar forecast)]

In cases where a counterfactual dispatch does not have sufficient supply offers to meet net load imbalance, we assign a penalty cost for procuring more energy. If the BA does not import from EIM, we extend its last economic bid segment. If the BA imports from EIM, we compare its last economic segment against the EIM LMP, and set the penalty price to the higher of the two. In summary, the penalty price per MWh is

- The highest offer price from the BA if the BA does not import from EIM,
- Max (the highest offer price from the BA, the transfer LMP) if the BA imports from EIM.

An EIM BAA may restrict the pool of dispatchable units in the counterfactual dispatch if that the BAA's practice prior to joining EIM was to balance real-time load from a limited pool.

ISO Counterfactual Dispatch

The ISO would need to meet load without EIM transfers in the counterfactual dispatch. The counterfactual dispatch is constructed in the following way:

1. Calculate the ISO's net EIM transfer;
2. Economically dispatch resources from the ISO to replace the transfer
   A. If the ISO is importing from the EIM,
      a. Find the ISO's undispatched supply with the variable cost (bid and three-part converted) greater than or equal to the reference transfer price;
      b. Sort and stack the supply by the variable cost from low cost to high cost; and
      c. Clear the supply stack from low cost to high cost up to the transfer megawatts
   B. If the ISO is exporting to the EIM,
      a. Find the ISO's dispatched supply with the variable cost (bid and three-part converted) less than or equal to the reference FMM transfer price;
      b. Sort and stack them by the variable cost from high cost to low cost; and

c. Clear the supply stack from high cost to low cost up to the transfer megawatts

The reference transfer price for the ISO is the maximum price of the incoming transfer points if the ISO is a net transfer importer, and the minimum price of the outgoing transfer points if the ISO is a net transfer exporter in RTD. Undispatched supply at lower bid cost than the reference price is dispatched out of merit when the ISO is importing transfer at the reference price. Dispatched supply at higher bid cost than the reference price is also dispatched out of merit when the ISO is exporting transfer at the reference price. The ISO has complex networks and constraints that are modeled in the EIM but not in the counterfactual. For example, supplies can be locally transmission constrained and undispatched in the EIM, which have available supply at lower bid cost than the LMP of the rest of the ISO. They should remain undispatched in the counterfactual even they have lower supply cost, because they are constrained by transmission. In the ISO's counterfactual dispatch, we only consider supplies above the reference transfer price to replace incoming transfer into the ISO, and thus preventing the transmission constrained lower cost supply being dispatched. Vice versa for the supplies below the reference transfer price to replace outgoing transfer. The counter factual dispatch (applies for whole EIM, not just the ISO) was based on 5-minute dispatch capability, and the reference price is the RTD price.

Counterfactual Dispatch

All EIM entities, with the exception of Pacificorp, have their counterfactual dispatch constructed in the following way. We will use NVE as an example.

1. Calculate the real-time net load imbalance for NVE;
2. Economically dispatch resources from NVE on top of the base schedules to meet NVE's net load imbalance
   A. If the net load imbalance is positive,
      a. Dispatch NV Energy's bid-in supply above base schedules;
      b. Sort and stack them by the variable cost from low cost to high cost; and
      c. Clear the supply stack from low cost to high cost up to the net load imbalance.
   B. If the net load imbalance is negative,
      a. Dispatch NV Energy's bid-in supply below base schedules;
      b. Sort and stack them by the variable cost from high cost to low cost; and
      c. Clear the supply stack from high cost to low cost up to the net load imbalance.

PacifiCorp Counterfactual Dispatch

PacifiCorp East BAA and PacifiCorp West BAA would need to meet demand without intra-hour transfers between PacifiCorp and the ISO, but transfers could occur between PACE and PACW in the counterfactual dispatch. The PacifiCorp counter factual dispatch will be constructed in the following way:

1. Calculate the real-time net load imbalance for each BAA;
2. Economically dispatch resources from PacifiCorp on top of the base schedules to meet net PacifiCorp load imbalance without violating the transfer limitations between PACE and PACW.
   A. If the net load imbalance is positive,
      a. Find PacifiCorp's bid-in supply above base schedules;
      b. Sort and stack them by the variable cost from low cost to high cost; and
      c. Clear the supply stack from low cost to high cost up to the net load imbalance subject to the transfer limit between PACE and PACW
   B. If the net load imbalance is negative,
      a. Find PacifiCorp's bid-in supply below base schedules;
      b. Sort and stack them by the variable cost from high cost to low cost; and
      c. Clear the supply stack from high cost to low cost up to the net load imbalance subject to the transfer limit between PACE and PACW

GHG Revenue

Greenhouse gas (GHG) revenue for a resource is equal to its GHG allocation MW times the GHG price.

GHG Cost

GHG cost for a resource is equal to its GHG allocation MW times its GHG bid.

Example

This example illustrates how the EIM benefit is calculated.

The transfers out of the EIM optimization are listed in Table 1. Base scheduled transfers have been excluded in the FMM transfers and RTD transfers.

From BAA	To BAA	FMM transfer	FMM transfer price	RTD incremental transfer	RTD transfer price	Transfer cost
PACE	NEVP	140	$26	10	$25	$3,890
NEVP	CISO	160	$26	20	$30	$4,760
PACE	PACW	190	$26	10	$25	$5,190

PACW	CISO	110	$26	-10	$30	$2,560

Table 1. An example of BAA to BAA transfers and prices

Assume the EIM energy imbalance and prices are as follows. Every BAA is balanced with Gen + Transfer – Load = 0. Assume the EIM optimization results in $1 GHG price, which means the ISO's LMP is $1 higher than the neighboring BAA (NEVP and PACW), because there is no congestion going into the ISO in the example. In the table below, positive transfer MW means the BAA is importing and negative transfer MW means it is exporting. Also, transfers in the table are sum of the transfers occur in both the FMM and the RTD with base scheduled transfer being excluded.

BAA	Gen	Load	Net transfer in MW	LMP	GHG price
CISO	0	280	280	$31	$1
NEVP	50	20	-30	$30	
PACE	150	-200	-350	$20	
PACW	100	200	100	$30	

Table 2. EIM energy imbalance and prices by BAA for one 5-minute interval

Transfer Cost

The transfers occur in both FMM and RTD, and their volume and prices are listed in Table 3. They are calculated from applying the convention that importing is positive and exporting is negative the BAA to BAA transfers, and summing them over all the neighboring BAAs.

BAA	transfer cost
CISO	$7,320 = $4,760+$2,560
NEVP	($870) = $3,890-$4,760
PACE	($9,080) = -$3,890-$5,190
PACW	$2,630 = $5,190-$2,560

Table 3. EIM transfer cost by BAA

For flex ramp, we calculate its transfer and transfer cost in Table 4.

BAA	Direction	Req.	Award	Allocation	Flex ramp transfer in	Flex ramp price	Flex ramp transfer cost

CISO	upward	150	100	75	-25	$1	-$25
NEVP	upward	10	0	5	5	$1	$5
PACE	upward	20	0	10	10	$1	$10
PACW	upward	20	0	10	10	$1	$10
CISO	downward	0	0	0	0	$2	$0
NEVP	downward	10	10	2	-8	$2	-$16
PACE	downward	20	0	4	4	$2	$8
PACW	downward	20	0	4	4	$2	$8

Table 4. Flex ramp transfer example

EIM Dispatch Cost

Now calculate the total bid cost associated with the EIM dispatches (delta from base schedules). The EIM dispatch costs are listed in Table 5.

BAA	Gen_EIM	EIM dispatch cost
CISO	0	$0
NEVP	50	$1,450
PACE	150	$2,700
PACW	100	$2,800

Table 5. EIM dispatch cost by BAA

Counterfactual Dispatch Cost

Then construct the counterfactual dispatches as described in the previous section, and sum up the counter factual dispatch cost for each BAA as shown in Table 6.

BAA	Gen_CF	Counterfactual dispatch cost
CISO	280	$9,240
NEVP	20	$640
PACE	-200	($3,800)

PACW	200	$6,200

Table 6. Counterfactual dispatch cost by BAA

GHG Cost and Revenue

The GHG costs associated with the 280 MW of importing transfer into CISO, and the revenues received by the GHG allocated MWs in both FMM and RTD are listed in Table 7.

BAA	GHG FMM MW	GHG RTD MW	GHG cost	GHG revenue
CISO	270	280	$0	-$280
NEVP	0	0	$0	$0
PACE	200	200	$20	$200
PACW	70	80	$75	$80

Table 7. GHG cost and revenue by BAA

EIM Benefit

With all the cost and revenue for each BAA available, we can use the formula EIM benefit for a BAA = counterfactual dispatch cost – (EIM dispatch cost + transfer cost + flex ramp transfer cost) + GHG revenue – GHG cost to calculate EIM benefit for each BAA. The results are shown in Table 8.

BAA	CF dispatch cost	EIM dispatch cost	Transfer cost	Flex transfer cost	GHG cost	GHG revenue	EIM benefit
CISO	$9,240	$0	$7,320	($25)	$0	($280)	**$1,665**
NEVP	$640	$1,450	($870)	($11)	$0	$0	**$71**
PACE	($3,800)	$2,700	($9,080)	$18	$20	$200	**$2,742**
PACW	$6,200	$2,800	$2,630	$18	$75	$80	**$757**

Table 8. EIM benefit for one 5-minute interval

This calculation is performed for each 5-minute interval with unit $/hr. We convert the $/hr benefit into the dollar benefit by multiplying 1/12. Then the 5-minute interval benefits in dollar amount can be aggregated into the monthly benefit by summing all the 5-minute intervals in the month.

CASE: UE 420
WITNESS: Rose Anderson

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 400

Opening Testimony

June 23, 2023

Q. Please state your name, occupation, and business address.

A. My name is Rose Anderson. I am a Senior Economist employed in the Energy Resource Planning Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/401.

Q. What is the purpose of your testimony?

A. My testimony discusses new coal contracts since the last TAM, the costs of the Jim Bridger gas conversion, and the allocation of the benefits of the Washington Cap and Invest permits received by PacifiCorp.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Confidential Exhibit Staff/402, consisting of 1 page.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. COAL CONTRACTS

Q. Please summarize the changes to PacifiCorp's coal contracts in the 2024 TAM.

A. As noted by PacifiCorp witness Owen, there are new and amended coal contracts included in the 2024 TAM. The following table is Staff's summary of the contracts that have changed since the 2023 TAM.

[BEGIN HIGHLY CONFIDENTIAL]

[redacted]

[END HIGHLY CONFIDENTIAL]

Q. Please discuss the current state of the coal market in Utah.

A. In Utah, PacifiCorp reports that the American Consolidated Natural Resources (ACNR) Lila Canyon Mine fire in September 2022 and other supply and demand side issues have resulted in scarce coal supply and increasing prices. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** coal contracts for its Utah coal plants have been updated in the 2024 TAM.

Q. Please discuss the changes to coal contracts in Utah in the 2023 TAM.

A. PacifiCorp reports that two Utah coal suppliers have filed Force Majeure claims that they cannot meet their obligations to the Company under existing contracts. For 2024, the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** have been affected. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

At Hunter, the third amendment to the Bronco CSA results in a **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**, and a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[1,2] The third amendment to the Bronco CSA extends through 2025.

A new Gentry contract at Hunter was signed in January 2023, after PacifiCorp issued a coal RFP. The contract provides **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in 2024, at a price of **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]**[3] The contract extends

---

[1] PAC/200, Owen/23.
[2] PAC/205, Owen/1.
[3] PAC/200, Owen/15.

through 2025, with a price of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for 2025.

The **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** [4] Staff has issued discovery requesting support for this assumed change.

Q. Does Staff have any concerns about the changes to coal contracts in Utah?

A. Yes. Certain changes have resulted in significant increases in coal prices. Staff is reviewing whether these changes were fully studied and the Company actions benefit customers. One could view the increased prices as the mines exercising monopoly power. For example, delivered coal costs from Bronco in the 2023 TAM were **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per ton.[5] The Second Amendment to the Bronco contract, which **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, was found to **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** in analysis provided by the Company in this docket compared to other alternatives.[6] However, no supporting analysis was provided for the third Bronco Amendment, which increased prices **[BEGIN CONFIDENTIAL]** [redacted]

[4] PAC/200, Owen/17.
[5] PAC/200, Owen/17.
[6] PAC/204, Owen/2.

[redacted] **[END CONFIDENTIAL]** Staff has issued discovery asking for supporting analysis.

Q. Is PacifiCorp managing its coal contracts and other system resources appropriately given the difficult circumstances?

A. Staff has used the Aurora archive provided by the Company to run the Aurora model and review the detailed output. PacifiCorp's TAM modeling shows that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** Given the coal supply issues in Utah, Staff is looking into whether the Company has utilized the full flexibility of its coal contracts, coal piles, and other resources outside of Utah to help reduce the impact of the coal supply difficulties in Utah. For example, has the Company explored increased coal volumes from coal mines it owns or from suppliers in Wyoming, Colorado, or Montana? Have market purchase prices been forecast accurately enough to reflect their value in providing flexibility when coal generators are constrained?

Based on Staff's initial review, the Company's Aurora modeling indicates that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** Staff is looking into the accuracy of the

Company's NOX limit assumptions, as well as whether the Company could have increased generation **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

For reference, Confidential Exhibit 402 filed with this Staff testimony includes a table of thermal plant capacity, average fuel cost, capacity factor, and NOX constraints in the 2024 TAM. The table provides helpful context for considering what options the Company may have to increase generation at its various thermal plants.[7]

Q. Generally, has PacifiCorp included adequate flexibility into the new coal contracts and taken every opportunity to increase flexibility when Force Majeure claims were made?

A. Some aspects of PacifiCorp's coal contracts are providing valuable flexibility in rapidly changing conditions. For example, PacifiCorp was able to negotiate a Wyodak coal contract without a minimum take agreement. Additionally, the contract duration is limited to 2025 for the new and amended Utah CSAs (with the exception of the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Additionally, the Third Amendment to the Bronco CSA **[BEGIN HIGHLY CONFIDENTIAL]** [redacted]

[7] Mitchel Direct ORTAM24 workpapers. NPC Summary tab. Row 1014.

[redacted] **[END HIGHLY CONFIDENTIAL]**

Staff appreciates the efforts the Company has made to increase contract flexibility. However, Staff is continuing to look into the actions PacifiCorp took in response to recent Force Majeure claims to manage cost and risk to customers. For example, did the Force Majeure claims provide PacifiCorp an opportunity to **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** Staff requests the Company explain in Reply Testimony whether it took steps to attempt to improve contract flexibility after Force Majeure claims were made, and why or why not.

Q. Does Staff have any concerns about how coal contracts were modeled for Hunter and Huntington in the 2024 TAM?

A. Yes. It appears that the Aurora model may not reflect the **[BEGIN HIGHLY CONFIDENTIAL]** [redacted]

[redacted] **[END HIGHLY CONFIDENTIAL]**

---

[8] PAC/200, Owen/4.

ISSUE 2. JIM BRIDGER GAS CONVERSION

Q. Please describe the Jim Bridger gas conversion.

A. PacifiCorp introduced its plan to convert the Jim Bridger 1 and 2 units to run on gas in its 2021 Integrated Resource Plan (IRP).[9] The conversion was found to reduce costs significantly for customers in terms of total portfolio NPVRR (inclusive of power costs and capital costs). In the IRP scenario where gas conversion was disallowed, the coal units were selected for retirement in 2023, resulting in a portfolio NPVRR cost increase of $447 million.

Q. What was the effect of the gas conversion in the 2024 TAM?

A. As PacifiCorp has discussed in Opening Testimony, if the units ran on coal instead of being converted to gas in 2024, total NPC in the 2024 TAM would be reduced by about $134 million.

Q. $134 million is a significant cost increase. Please discuss the reasons for the cost increase.

A. The conversion of Jim Bridger 1 and 2 to gas in 2024 occurs at a time when coal supply and NOX emissions are constrained, and natural gas prices have increased. Coal consumption is expected to decrease by **[BEGIN CONFIDENTIAL]** [redacted]

[9] PacifiCorp's 2021 Integrated Resource Plan, page 15.
[10] PAC/100, Mitchell/37.
[11] PAC/200, Owen/24.

[redacted] **[END CONFIDENTIAL]**.

Q. Does this indicate that the converted gas units will always cost a similar amount in each successive TAM filing.

A. Not necessarily. In this year's TAM, the converted gas units run at **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** The Jim Bridger 1 and 2 units, which are inefficient units with full load heat rates of about **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** (compared to a heat rate of about **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for a more efficient combined cycle gas unit), would usually be best run as peaking units. **[BEGIN CONFIDENTIAL]** [redacted]

[redacted]

[END CONFIDENTIAL]

Q. Is the reliance on [BEGIN CONFIDENTIAL] [redacted] **[END CONFIDENTIAL] a reasonable approach to reducing the cost to customers associated with the Utah coal supply issues?**

A. Staff is continuing to look into this question. It is possible there are other ways to respond to the Utah coal market issues, for example by purchasing more energy from market, or increasing output from other coal plants. It is unclear whether all reasonable steps have been taken to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

However, as described in the Coal Contracts section of my testimony above, based on Staff's initial review, the Company's Aurora modeling indicates that **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] **[END CONFIDENTIAL]** Staff is looking into the accuracy of the Company's NOX limit assumptions, as well as whether the Company could have increased generation **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

ISSUE 3. WASHINGTON CAP AND INVEST

Q. Please describe the Washington Cap and Invest modeling update.

A. PacifiCorp has updated the Aurora model to include a Cap and Invest cost adder of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** to Chehalis dispatch.

Q. Does Staff have any issue with this change?

A. Yes, PacifiCorp is expected to receive some free permits to reduce the cost of the program to customers. It appears that PacifiCorp has not allocated the benefits of these free permits to Oregon customers, instead allocating the benefit of the permits to Washington customers only. This creates an unfair distribution of an asset received by the Company among Washington and other PacifiCorp jurisdictional customers.

Q. Is PacifiCorp required to allocate all free permits to Washington customers?

A. It does not appear so. The legislation and rules state that they intend to alleviate "cost burden" for "customers of electric utilities in Washington state."[12,13] Additionally, the quantity of permits is calculated based on the load of Washington customers. However, upon Staff's initial review of the legislation and rules, there does not appear to be a requirement that the permits should be provided only to customers located in Washington.

Q. Does Staff recommend an adjustment?

[12] Washington Senate Bill 5126. 2021.
[13] Chapter 173-446 WAC – Climate Commitment Act Program Rule.

A. Yes, to remedy the fairness issue of allocating free permits only to Washington customers, Staff recommends that in the 2024 TAM, Oregon customers should be allocated the benefits of the value of the free permits on a System Generation (SG) basis.

Q. Even if Washington law requires the permits be assigned to PacifiCorp's Washington customers, would you still recommend the benefit of the permits be allocation on a SG Factor across all the states?

A. Yes. Since all states are allocated the costs of Chehalis, both operation and fixed, for allocation purposes, it seems reasonable to allocate the benefit of the permits across PacifiCorp's jurisdictional states. To do otherwise would make it appear that Washington is exporting the costs of its energy policies to other states while protecting Washington customers from such costs. That does not seem fair or equitable.

Q. What is Staff's adjustment on this issue?

A. The Staff adjustment is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Q. Does this conclude your direct testimony?

A. Yes

CASE: UE 420
WITNESS: Rose Anderson

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 401

Witness Qualifications Statement

June 23, 2023

WITNESS QUALIFICATION STATEMENT

NAME:	Rose Anderson
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Economist Energy Resources and Planning Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	Master of Science, Agriculture and Resource Economics, University of California Davis, Davis, CA Bachelor of Arts, International Political Economy University of Puget Sound, Tacoma, WA
EXPERIENCE:	I have been employed at the Public Utility Commission of Oregon since September of 2016. My position is Senior Economist in the Energy Resources and Planning Division. I perform economic and policy analysis, including analysis of cost and risk in Integrated Resource Plans and resource economics in Rate Cases. I have participated in OPUC rate cases including UE 319, UG 325, UG 344, and UE 399, and OPUC power cost dockets including UE 320, UE 323, UE 333, and 335, UE 375, and UE 400. Prior to working for the PUC I was a Research Associate at McCullough Research for two years. My responsibilities included economic analysis of energy markets and utilities.

CASE: UE 420
WITNESS: Rose Anderson

PUBLIC UTILITY COMMISSION
OF
OREGON

CONFIDENTIAL STAFF EXHIBIT 402

Exhibits in Support
Of Opening Testimony

June 23, 2023

CASE: UE 420
WITNESS: MADISON BOLTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 500

Opening Testimony

June 23, 2023

Q. Please state your name, occupation, and business address.

A. My name is Madison Bolton. I am a Senior Energy and Policy Analyst employed in the Utility Strategy and Integration Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/501.

Q. What is the purpose of your testimony?

A. I analyze expense for qualifying facilities (QFs) and the calculation of Direct Access charges in PacifiCorp's 2024 Transition Adjustment Mechanism (TAM) filing, Docket No. UE 420.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared Exhibit Staff/502 consisting of PacifiCorp's responses to Staff data requests.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. QUALIFYING FACILITIES

Q. Please discuss QFs and the methodology for their inclusion in the TAM.

A. Under the Public Utility Regulatory Policies Act of 1978 (PURPA), investor-owned utilities are required to purchase power from QFs at rates set by state regulatory commissions. Forecasted costs of energy purchases from QFs are included in the revenue requirement for PacifiCorp's TAM. It has historically been difficult to accurately forecast the costs associated with purchasing energy from new QFs coming on-line during the TAM forecast period. This is because new QFs frequently miss their scheduled on-line date, but PacifiCorp has limited means of knowing in advance whether a particular QF will meet the scheduled on-line date.

In the 2018 TAM, Docket No. UE 323, the Oregon Public Utility Commission directed PacifiCorp to calculate a Contract Delay Rate (CDR) using a historical three-year rolling average of delays for new QFs to more accurately reflect the rate impact of forecast errors due to contract delays.[1] The Commission also adopted a methodology to weight the CDR by QF size beginning in the 2019 TAM.[2]

Q. Has the Company proposed any changes to the methodology for the CDR?

1 *In the Matter of PacifiCorp, dba Pacific Power, 2018 Transition Adjustment Mechanism*, UE 323, Order No. 17-444, p.17 (November 1, 2017).
2 Id.

A. No. It appears that PacifiCorp is using the approved methodology from the 2019 TAM. Additionally, the CDR is not used for purposes of forecasting NVPC in this case because no new QFs are expected to come online in the 2024 TAM forecast period.[3]

Q. Has the Company proposed any other forecasting changes for QFs?

A. The Company has not proposed a forecasting change related to QFs. PacifiCorp did implement a change stipulated to in the previous TAM. In the 2023 TAM, Docket No. UE 400, the Company concluded that one of the main sources of routine QF over-forecasts was attributed to QFs less than 10 megawatts (MW) in capacity.[4] In UE 400, the Commission adopted a stipulation requiring PacifiCorp to forecast generation for all QFs for which it has historical data using a 48-month normalization based on historical data to improve the forecast accuracy.[5]

Q. Describe Staff's concerns with QF forecasting.

A. Staff has outlined concerns about QF over forecasts in both the 2022 TAM and 2023 TAM. In the 2022 TAM, Staff recommended a downward adjustment to PAC's forecasted QF costs, pointing to historical information showing PacifiCorp's consistent over-forecast. The Commission rejected the proposed adjustment, noting it appeared too much like a line-item true-up. The Commission explained that "[i]dentifying a single cost or revenue that varies

3 Staff/502, Bolton/1, PacifiCorp Reply to Staff DR No. 76.
4 UE 400, Reply Testimony, PAC/600, Mitchell/60, at 2.
5 *In the Matter of PacifiCorp, dba Pacific Power*, *2023 Transition Adjustment Mechanism,* UE 400, Order No. 22-389, App. A, p. 5 (October 25, 2022).

from base rates, without updating base rates as a whole or adjusting for other variations, could result in TAM updates that are not equal, with an imbalance between the cost items that favor PacifiCorp with the revenue items that favor customers."[6] However, the Commission directed PacifiCorp to provide data comparing the forecast to actual QF generation and to explain the source of over forecasting.[7]

In the 2023 TAM, PacifiCorp claimed that the accuracy rate for QF forecasts has been improving since 2017.[8] After updating the data for 2022, Staff is not convinced that the accuracy rate is improving. Please refer to Confidential Figure 1, demonstrating forecast error percentages since 2017.

<u>Confidential Figure 1.</u>

	Difference between Forecast and Actuals (%)
	QFs (MWh)
Year	Percent
2017	[redacted]
2018	
2019	
2020	
2021	
2022	
Average	

6 *In the Matter of PacifiCorp, dba Pacific Power 2022 Transition Adjustment Mechanism*, UE 390, Order No. 21-379 p. 36 (November 1, 2021).

7 *In the Matter of PacifiCorp, dba Pacific Power 2022 Transition Adjustment Mechanism*, UE 390, Order No. 21-379 p. 38 (November 1, 2021).

8 UE 400, Reply Testimony, PAC/600, Mitchell/60 at 13.

Staff notes that the Company has only started forecasting QFs using a 48-month normalization in the 2024 TAM, therefore the accuracy of the new method cannot be ascertained by looking at the historical percentages of over forecasts. While the updated forecasting method for QFs, including smaller QF's under 10 MW, may improve the forecasting errors in the future, Staff is concerned that the current QF forecasting mechanism continues to incentivize the Company to over forecast, which presents risk to customers and has created administrative burden requiring significant input from Staff, parties and the Commission in annual power cost dockets and rate case proceedings.

Q. Based on the Company's historical over forecasting, what is Staff's recommendation?

A. Ultimately, Staff's only recommendation for QF power costs in the 2024 TAM is that the Company continues to update the forecast error percentage in Confidential Figure 1 with the latest available data in subsequent TAM filings.

Staff has previously recommended implementing a pass-through mechanism for QF purchased power costs in Docket No. UE 399,[9] but stipulating parties agreed to not adopt changes to the TAM and PCAM as part of the third partial stipulation in that case.[10] Additionally, Staff is not proposing to adopt the pass-through mechanism in this case, as PAC's 2024 TAM is not taking place concurrently with a general rate case. However, Staff reiterates that a pass-through mechanism would limit over or under forecasting and

[9] UE 399, Opening Testimony, Staff/900, Enright/27 at 5.
[10] *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision,* Order No. 22-491, Appendix C, p. 12, at 6 (December 16, 2022).

would improve the current process that has incentivized over forecasting QF costs in previous years. Staff notes that the proposed QF pass through in UE 399 would function as originally described below by Staff Witness Moya Enright:

> In the TAM, PAC would forecast QF costs using a four-year moving average of historical QF generation while also including new QFs with CODs in the test year. In the PCAM, PAC's actual QF costs would be compared to the forecasted costs, and the resulting surplus or deficit would be passed through as either a charge or a refund to customers based on the day-ahead Mid-C power price for replacement power, or the difference between the Mid-C price and the QF contract price in the event of surplus generation. The price for the Mid-C would include a weighting of the light load and heavy load hours by the respective hours in the day until a better method is identified.[11]

Staff has also recommended a similar QF pass-through proposal for Portland General Electric (PGE) in UE 402, which PGE has proposed to implement with some modifications.[12]

---

[11] UE 399, Opening Testimony, Staff/900, Enright/27 at 10-21.
[12] UE 416, PGE/300, Schwarts—Outama—Cristea/51.

ISSUE 2. DIRECT ACCESS AND CONSUMER OPT-OUT CHARGE

Q. Please describe the topics you analyzed involving Direct Access.

A. I reviewed the Company's calculation of the Direct Access (DA) transition adjustments and the consumer opt-out charge. The transition adjustments represent the value of the projected market price of power that becomes available when a customer opts to leave cost-of-service (COS) supply for Direct Access. This projection is used to determine a weighted market value for the energy which is compared to the customer's tariff rate to determine the actual adjustment.

The Consumer Opt-Out Charge (COOC) is a specific transition adjustment for the Company's five-year direct access program. It is intended to recover transition costs incurred during years six through 10 after the departure of DA load. In the first five years, the DA customer pays the Schedule 200 retail rates and the COOC. The COOC is calculated as a forecast of Schedule 200 costs for years six through 10, using the Schedule 200 costs at the time of the customer's departure and then escalating those costs using an inflation escalator. The Company then uses the forecasted Schedule 200 values to construct a levelized payment for years one through five.

Q. Did Staff find any errors in the Company's work papers and the calculation of the transition adjustments or COOC?

A. Upon review, the Company's calculation of both DA adjustments appears correct. Staff notes that in Order No. 21-379 in UE 390, the Commission adopted Staff's recommendation for the Company to utilize its approved methodology to calculate the COOC as a floating mechanism that can go below zero. It is Staff's understanding that the Company has calculated the COOC consistent with the Commission's Order in UE 390. Order No. 21-379 also clarifies that the appropriate docket to make a final determination on the COOC methodology is in UM 2024.[13] However, since this issue has not been settled in UM 2024, the Company should continue to calculate the COOC as described above. Staff notes that transition charges, such as the Company's COOC, are in place to prevent cross-subsidization between DA and COS customer classes, and until a more thorough determination can be made as part of the proceedings in UM 2024, the COOC should continue to be able to go below zero in order to avoid a methodological bias towards subsidization of COS customers.

Q. Does this conclude your testimony?

A. Yes.

[13] *In the Matter of Alliance of Western Energy Consumers, Petition for Investigation Into Long-Term Direct Access Programs*, Docket No. UM 2024, Order No. 21-379 (November 1, 2021).

CASE: UE 420
WITNESS: MADISON BOLTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 501

Witness Qualifications Statement

June 23, 2023

WITNESS QUALIFICATIONS STATEMENT

NAME:	Madison Bolton
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Utility Analyst Utility Strategy & Integration Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	B.A. Carroll College, Helena, Montana Major: Biology, 2017 M.ENV. University of Colorado, Boulder, Colorado Specialization: Renewable and Sustainable Energy, 2020
EXPERIENCE:	Since September 2021, I have been employed by the Oregon Public Utility Commission. I currently hold the position of Utility Analyst 3 in the Utility Strategy and Integration Division, where I've evaluated utility voluntary renewable energy products and direct access issues. I have provided witness testimony on multiple general rate case and power cost dockets, including: UG 433, UG 435, UE 399, UE 400, UE 402, and UE 416. From 2019 to 2020 I worked as a graduate research analyst at E Source where I conducted research for utility clientele on large non-residential energy consumers. Additionally, in 2020 I assisted Camus Energy in researching the feasibility of electric grid management software.

CASE: UE 420
WITNESS: MADISON BOLTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 502

PacifiCorp's Reply to Staff Data Request No. 76

June 23, 2023

UE 420 / PacifiCorp
June 12, 2023
OPUC Data Request 76

OPUC Data Request 76

Qualifying Facilities (QF) - For 2024, for those QFs that have executed contracts that have a projected commercial operation date in 2024, what percentage of these QFs is the Company assuming will begin operations in 2024? Please consider this an ongoing request for an updated response should the information provided change during the course of this filing.

Response to OPUC Data Request 76

The percentage is currently zero because there are no new qualifying facilities (QF) scheduled to come online / become commercially operational in calendar year 2024 that are included in the Company's 2024 transition adjustment mechanism (TAM) as referenced in the Company's response to OPUC Data Request 75.

CASE: UE 420
WITNESS: Itayi Chipanera

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 600

Opening Testimony

Wind Production Tax Credits

June 22, 2023

Q. Please state your name, occupation, and business address.

A. My name is Itayi Chipanera. I am a Senior Financial Analyst employed in the Accounting and Finance Section of the Rates, Safety, and Utility Performance (RSUP) program of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualifications statement is found in Exhibit Staff/601.

Q. What is the purpose of your testimony?

A. I analyze treatment of Production Tax Credits (PTCs) in PacifiCorp's (PacifiCorp, PAC, or Company) 2024 Transition Adjustment Mechanism (TAM) filing, Docket No. UE 420.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. WIND PRODUCTION TAX CREDITS

Q. How are Production Tax Credits (PTCs) treated in PacifiCorp's TAM?

A. The NPC forecast includes the forecasted value of the PTCs PacifiCorp will earn during the test period. To calculate the PTC value for the test period, PAC multiplied the qualifying generation by the current PTC rate of 2.9 cents per kilowatt-hour (kWh) for pre-2022 projects or the current PTC rate of 3.0 cents per kWh for projects placed in service after 2022, and then grossed-up for taxes.[1] The Company has forecasted an Oregon-allocated $80.4 million in PTCs for the 2024 TAM resulting in an increase of $10.2 million compared to the 2023 TAM.

Q. What is PAC's forecasted wind generation on owned plant in 2024?

A. The Company's forecasted wind generation as filed in the 2024 TAM is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** megawatt hours (MWH)[2] on a Company-wide basis. This forecast includes expected production of the Company's new Foote Creek II, III and IV facilities, which are expected to enter service in January 2024.

Q. Did Staff review the Company's wind power generation forecasts on owned plants in 2024?

A. Yes. Staff reviewed the Company's actual wind generation from Data Request No. 7 and compared the actual generation to forecasts presented in the current and prior TAM filings. Staff's review of the Company's wind

---

[1] PAC/100, Mitchell/40.
[2] PAC/100, Mitchell/41.

power generation shows that the Company has a history of forecasting higher wind generation than actual results. The issue of higher wind generation than realized has been pointed out by other Commission Staff in the past. The Company acknowledges this trend in its current testimony:

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. Does the Company propose to address this over-forecasting in this TAM?

A. Yes. The Company states that its "trapped energy modeling enhancement, now shows the 2024 forecast to be more accurate, within 2.0% of 2022 actual wind generation as compared to the historical average 11.0% over-forecast of wind generation."[4]

Q. Is the Company's "trapped energy modeling enhancement" sufficient to address the over forecasting of wind generation?

A. It is Staff's position that the Company did not provide sufficient back testing evidence of their new forecasting methodology for Staff to properly evaluate the enhancement's effectiveness. Staff proposes to adjust the forecast

[3] PAC/100, Mitchell/41.
[4] PAC/100, Mitchell/41.

method to the Company's 2024 wind generation to use a four-year average of actual results for each power generating facility. For facilities with less than four years of full operating history Staff propose to use the Company's forecast unadjusted as presented in the filing. However, for this filing the Staff proposed forecasts use a three-year average and do not include actual results from calendar year 2019. The generation from 2019 is affected by what should be a one-time event of a substation fire that caused PacifiCorp to curtail wind production at some east-side wind facilities.

Q. Are there any other proposed adjustments to the company's wind generation forecast?

A. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** percent as recently agreed in a forthcoming settlement term sheet in UE 419 concerning PGE's Renewable Adjustment Clause.

Q. What is the proposed adjustment amount to the Company's wind generation forecast? [BEGIN CONFIDENTIAL]

A. [redacted]

[redacted]. **[END CONFIDENTIAL]**

Q. In your testimony above, you note the PTC rate used by PAC to calculate the PTCs in the forecast period. Does the PTC rate change every year?

A. Yes. The PTC rate is adjusted for inflation every year. Over the last year inflation has continued to come down from a high of 8 percent in the first quarter of 2022 to 4 percent as of May 2023. Although the inflation rate is still above the Federal Reserve Bank target of 2 percent, the Federal Open Market Committee (FOMC) decided not to change the federal funds target rate at the June 2023 meeting.[5] It is not apparent how inflation and interest rates will change over the second half of the year and their subsequent impact on the PTC rate in 2024.

Q. Is Staff proposing any adjustment to the Company's PTC benefits?

A. Yes, Staff is proposing to increase the Company's Oregon allocated PTC credit by $1.3 million based on Staff's adjustment to the Company's forecasted wind generation during the test period. The table below shows the components of the proposed increase.

[5] FOMC Press Release, June 14 2023.

Resource	UE 420 Filed Wind Generation Forecast (MWh)	Staff Proposed Wind Generation Forecast (MWh)	Staff Proposed Additional Wind Generation Forecast (MWh)	Staff Proposed PTC Initial Adjustment	10% Bonus Credit	Oregon Allocation Factor	Staff Proposed PTC Adj with Bonus - Oregon Allocation	Gross Up Factor	Revenue Requirement on Staff Adjustment
Foote Creek II	[redacted]	[redacted]	[redacted]	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]	[redacted]	$ [redacted]
Foote Creek III	[redacted]	[redacted]	[redacted]	$ [redacted]	$ [redacted]	[redacted]	[redacted]	[redacted]	$ [redacted]
Foote Creek IV	[redacted]	[redacted]	[redacted]	$ [redacted]	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]
All Other Facilities	[redacted]	[redacted]	[redacted]	$ [redacted]	N/[redacted]	[redacted]	[redacted]	[redacted]	$ [redacted]
Total	[redacted]	[redacted]	[redacted]	**$** [redacted]			[redacted]		**$** [redacted]

[redacted]

2). For all other facilities the forecast increased due using a 3 year average of actual generation of as the forecast where, three year history is available

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 420
WITNESS: Itayi Chipanera

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 601

Witness Qualifications Statement

June 23, 2023

WITNESS QUALIFICATIONS STATEMENT

NAME:	Itayi Chipanera
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Financial Analyst Accounting and Finance Section
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	B.S., Economics Idaho State University M.S., Mathematics University of Nevada – Reno M.S., Accounting Indiana University – Bloomington
EXPERIENCE:	I have been employed by the OPUC in the Safety, Rates and Utility Performance Program since April of 2023. Prior to my employment with the OPUC I was employed in various finance roles in the insurance and banking industries including Advantis Credit Union where I was employed as a Senior Risk and Financial Analyst; City of Salem, Oregon, where I was a Finance Management Analyst; and, SAIF Corporation where I was an Actuarial Research Analyst.

CERTIFICATE OF SERVICE

UE 420

I certify that I have, this day, served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-001-0180, to the following parties or attorneys of parties.

Dated this 23rd day of June, 2023 at Salem, Oregon

Kay Barnes

Kay Barnes
Public Utility Commission
201 High Street SE Suite 100
Salem, Oregon 97301-3612
Telephone: (971) 375-5079

UE 420
Service List

AWEC	
BRENT COLEMAN **(C)** **(HC)** DAVISON VAN CLEVE	1750 SW HARBOR WAY, SUITE 450 PORTLAND OR 97201 blc@dvclaw.com
JESSE O GORSUCH **(C)** **(HC)** DAVISON VAN CLEVE	1750 SW HARBOR WAY STE 450 PORTLAND OR 97201 jog@dvclaw.com
CORRINE OLSON **(C)** **(HC)** DAVISON VAN CLEVE	1750 SW HARBOR WAY, STE. 450 PORTLAND OR 97201 coo@dvclaw.com
CALPINE SOLUTIONS	
GREGORY M. ADAMS **(C)** RICHARDSON ADAMS PLLC	515 N 27TH ST BOISE ID 83702 greg@richardsonadams.com
GREG BASS CALPINE ENERGY SOLUTIONS, LLC	401 WEST A ST, STE 500 SAN DIEGO CA 92101 greg.bass@calpinesolutions.com
KEVIN HIGGINS **(C)** ENERGY STRATEGIES LLC	215 STATE ST - STE 200 SALT LAKE CITY UT 84111-2322 khiggins@energystrat.com
KWUA	
KWUA KLAMATH WATER USER ASSOCIATION KLAMATH BASIN WATER USER PROTECTIVE ASSOCIATION	2312 SOUTH SIXTH STREET, STE A KLAMATH FALLS OR 97601 assist@kwua.org
PAUL S SIMMONS **(C)** **(HC)** SOMACH SIMMONS & DUNN	500 CAPITOL MALL, STE 1000 SACRAMENTO CA 95814 psimmons@somachlaw.com
OREGON CITIZENS UTILITY BOARD	
MICHAEL GOETZ **(C)** **(HC)** OREGON CITIZENS' UTILITY BOARD	610 SW BROADWAY STE 400 PORTLAND OR 97205 mike@oregoncub.org
ROBERT JENKS **(C)** **(HC)** OREGON CITIZENS' UTILITY BOARD	610 SW BROADWAY, STE 400 PORTLAND OR 97205 bob@oregoncub.org
Share OREGON CITIZENS' UTILITY BOARD OREGON CITIZENS' UTILITY BOARD	610 SW BROADWAY, STE 400 PORTLAND OR 97205 dockets@oregoncub.org

PACIFICORP	
PACIFIC POWER	825 NE MULTNOMAH ST, STE 2000 PORTLAND OR 97232 oregondockets@pacificorp.com
AJAY KUMAR **(C)** **(HC)** PACIFIC POWER	825 MULTNOMAH ST., STE. 2000 PORTLAN OR 97232 ajay.kumar@pacificorp.com
SIERRA CLUB	
LEAH BAHRAMIPOUR **(C)** SIERRA CLUB	2101 WEBSTER STREET, SUITE 1300 OAKLAND CA 94612 leah.bahramipour@sierraclub.org
ROSE MONAHAN **(C)** SIERRA LCU	2101 WEBSTER ST STE 1300 OAKLAND CA 94612 rose.monahan@sierraclub.org
STAFF	
STEPHANIE S ANDRUS **(C)** **(HC)** Oregon Department of Justice	BUSINESS ACTIVITIES SECTION 1162 COURT ST NE SALEM OR 97301-4096 stephanie.andrus@doj.state.or.us
VITESSE LLC	
DENNIS BARTLETT **(C)** META PLATFORMS INC	1 HACKER WAY MENLO PARK CA 94025 dbart@meta.com
LIZ FERRELL **(C)** META PLATFORMS INC	1 HACKER WAY MENLO PARK CA 94025 eferrell@meta.com
IRION A SANGER **(C)** **(HC)** SANGER LAW PC	4031 SE HAWTHORNE BLVD PORTLAND OR 97214 irion@sanger-law.com