Oregon
Kate Brown, Governor

Public Utility Commission
201 High St SE Suite 100
Salem, OR 97301
Mailing Address: PO Box 1088
Salem, OR 97308-1088
Consumer Services
1-800-522-2404
Local: 503-378-6600
Administrative Services
503-373-7394

May 25, 2022

Via Electronic Filing

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

RE: Docket No. UE 400– In the Matter of PACIFICORP, dba PACIFIC POWER, Transition Adjustment Mechanism.

Attached for filing are the following:

- Exhibit 100-102 CONF
- Exhibit 200-204 CONF
- Exhibit 300-302 CONF
- Exhibit 400-402 CONF
- Exhibit 500-503 CONF
- Exhibit 600-602 HI-CONF
- Exhibit 700-702
- Exhibit 800-802

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

CASE: UE 400
WITNESS: MOYA ENRIGHT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

Opening Testimony

May 25, 2022

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

A. My name is Moya Enright. I am a Senior Economist employed in the Rates Finance and Audit 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 qualification statement is found in Exhibit Staff/101.

Q. What is the purpose of your testimony?

A. My testimony is presented in two sections. First, as Staff's summary witness, I will present an overview of PacifiCorp's 2023 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, Order No. 21-379 resulting from the most recent 2022 TAM, and Order No. 20-392 concluding the 2021 TAM. Finally, I introduce the Company's three Energy Imbalance Market (EIM) benefit forecasts, and discuss my analysis of the Company's Greenhouse Gas (GHG) benefit forecast.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared the following Staff Exhibits:

- Staff/101: Witness Qualification 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 2023 TAM FILING

Q. Please summarize PacifiCorp's 2023 TAM filing.

A. The Company has forecasted 2023 Net Power Costs (NPC) of $1,684 million, representing an increase of approximately $314 million system-wide, or a $78.4 million increase on an Oregon only basis.[1] This represents a 22 percent increase in NPC compared with the final 2022 forecast,[2] and a nine percent increase in NPC compared with the period from 2016 through 2020 (the latest years for which incurred NPC have been finalized).[3]

In this filing, PacifiCorp has replaced its previous production cost forecasting model GRID with Aurora for the first time. PacifiCorp's switch to using the Aurora model had been expected in the 2021 TAM, however was delayed due to the COVID-19 pandemic.[4] Along with its move to the Aurora model, the Company is proposing multiple changes to its modeling methodology.

Q. What is really driving the forecasted $314 million increase in NPC?

A. In direct testimony, PacifiCorp explains that this significant increase in forecasted costs is driven by multiple factors, including high gas and power market prices.[5] PacifiCorp also suggests that the 2022 TAM forecast, against which this filing is compared above, may have been too low.[6]

---

1 PAC/101 Wilding/1.
2 PAC/100, Wilding/3 or Exhibit PAC/101, Wilding/1, line 35.
3 PAC/100 Wilding/5.
4 UE 390, PAC/100, Webb/23, lines 12 - 17.
5 PAC/100, Wilding/4.
6 PAC/100, Wilding/6.

In truth, 51 percent of the increase in forecasted 2023 NPV is caused by modelling changes that PacifiCorp is proposing to implement in this filing ($159.2 million of the $314.5 million system-wide increase). PacifiCorp's modelling changes in this filing include:

1. Proposed change to market caps methodology, increasing NPC by $22.7 million.[7]
2. Proposed new methodology for forecasting the Company's Regulation Reserve Margin requirement, resulting in a $67.5 million increase to NPC.[8]
3. Proposed change to the Company's methodology for forecasting the planned outages in the TAM, resulting in a $13.9 million increase to NPC.[9]
4. Proposed change to the calculation of the Company's DA/RT price adder, driving a $20 million increase to NPC.[10]
5. Proposed change to valuation of trapped energy, resulting in a $0.2 million increase to NPC.[11]
6. Proposal to change the thermal attributes of PacifiCorp's generators during summer months, driving a $23.8 million increase in NPC.[12]

---

7 PAC/100, Wilding/33.
8 PAC/100, Wilding/33.
9 PAC/100, Wilding/35.
10 PAC/100, Wilding/36.
11 PAC/100, Wilding/36.
12 PAC/100, Wilding/38.

7. Proposed inclusion of start-up costs for natural gas generators in the forecast, resulting in a $6.2 million increase to NPC.[13]

8. The removal of the "must run" condition on coal units in Aurora, allowing for their economic cycling, in accordance with Order No. 20-392, resulting in a $4.9 million increase to NPC.[14]

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

A. PacifiCorp's initial filing forecasts a 42 percent ($252 million) reduction in revenue from power sales, and 7 percent ($47 million) reduction in coal expenses. Gas expenses are forecasted to increase by 7 percent ($21 million), while wheeling costs and purchased power costs are also forecasted to increase by 6 percent ($10 million) and 9 percent ($78 million)

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Confidential Figure 1 - 2023 TAM vs. 2022 TAM vs. 2021 PCAM[15]

---

13 PAC/100, Wilding/39.
14 PAC/100, Wilding/39.
15 Staff/102, Enright/1-4, PACs Response to Staff DR 32 and associated Confidential Attachments. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

respectively. Year-on-year changes between expenses and revenues forecasted in the 2023 TAM and 2022 TAM are summarized in Figure 1.

The overall changes in costs tally with the change in forecasted fuel mix. The 2023 TAM shows **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** percent of PacifiCorp's requirements being met by coal, down from **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** percent in the final update to the previous year's forecast. This is offset by power purchases increasing from **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** percent to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** percent of the Company's fuel mix. The proportions of each fuel type are summarized below in confidential Figure 2.

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Confidential Figure 2 - TAM Forecasted Fuel Mix, 2015 - 2023[16]

[16] Staff/102, Enright/5-7, PAC Response to Staff DR 33 and associated Confidential Attachments.

Other forecasted generation sources are forecasted to generate **[BEGIN CONFIDENTIAL]** [redacted] **[BEGIN CONFIDENTIAL]** the previous year's TAM, with forecasted wind generation **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

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

A. Oregon-allocated NPC are forecasted to total $429.1 million.[17] This represents a $78.4 million, or 22.4 percent, increase on the 2022 NPC forecast.[18]

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

A. Staff's review has focused on the main expenses forecasted by the Company, and on the modeling changes that the Company has proposed. Staff has also reviewed the Company's compliance with recent TAM Orders, giving particular attention to the Company's obligations relating to coal generators.

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

A. Staff's proposed adjustments total ($133.5) million on a total-company basis, or $35.5 million on an Oregon-allocated basis, as demonstrated in Figure 3 below.

[BEGIN CONFIDENTIAL]

[17] PAC/101, Wilding/1.
[18] PAC/101, Wilding/1.

Staff issue #	Issue	System-Wide	Oregon-Allocated
Staff/100, Issue 2	EIM GHG Benefit	[redacted]	[redacted]
Staff/200, Issue 2	DA-RT Price Adder	(20,009,226)	(5,216,405)
Staff/300, Issue 1	Market Capacity Update	(22,651,343)	(5,905,205)
Staff/300, Issue 2	EIM Energy Transfer Benefit	(33,444,185)	(8,718,899)
Staff/400, Issue 1	Production Tax Credit rate	[redacted]	[redacted]
Staff/400, Issue 3	QF Forecast	[redacted]	[redacted]
Staff/500, Issue 1	Planned Outages	(13,893,198)	(3,621,957)
Staff/500, Issue 2	Thermal Attributes Update	(23,829,806)	(6,212,430)
Staff/600, Issue 1	Naughton CSA	(1,777,375)	(463,362)
Staff/600, Issue 5	Huntington Analysis	(50,000)	(50,000)
Staff/600, Issue 6	Economic Cycling Study	(50,000)	(50,000)
Staff/600, Issue 7	Min Take Modeling / Reporting	(50,000)	(50,000)
Total Adjustments		**(133,457,990)**	**(35,542,574)**
Forecasted 2023 NPC		1,683,929,925	429,129,432
Forecasted 2023 NPC incl. Staff adjustments		**1,550,471,935**	**393,586,858**
Final 2022 NPC		1,369,404,716	350,692,386

[END CONFIDENTIAL]

Confidential Figure 3 - Effect of Staff Adjustments on Forecasted NPC

Including Staff's adjustments in the forecast of NPC would lead to an overall increase in Oregon NPC of $42.9 million compared with 2022 NPC, representing a 12.2 percent increase in NPC for 2023, in contrast to the $78.4 million, or 22.4 percent increase in NPC proposed for Oregon by PacifiCorp.

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

A. Staff/100 provides an overview of the filing, a review of the Company's compliance with the TAM guidelines and Commission Orders, and an adjustment related to the Company's EIM GHG benefit forecast.

In Staff/200, witness Heather Cohen addresses the standard updates to the Company's TAM filing, trapped energy revenue and emergency purchases, and the Company's DA/RT adder.

In Staff/300, witness Curtis Dlouhy addresses the Company's proposed change to the modelling of market caps, the EIM energy benefit transfer forecast, rate spread, inter-jurisdictional allocations, and the Company's load forecast.

In Staff/400, witness Madison Bolton addresses the Company's forecast of costs for purchases from Qualifying Facilities (QF) in the test year, along with the Commission-ordered report on QF forecasting. Mr. Bolton's analysis also includes the Company's forecasted Production Tax Credit (PTC) and wind benefits, and the calculation of Direct Access rates.

In Staff/500, witness Brian Fjeldheim addresses the Company's proposed changes to its methodology for modeling planned maintenance outages, maximum generator capacities, and the regulating reserve requirement.

In Staff/600, witness Steve Storm addresses the Company's modelling of coal generation vis-à-vis recent TAM Orders, and the Company's long term fuel plan for the Jim Bridger plant.

In Staff/700, witness Ryan Bain addresses wheeling expenses valued at $160.8 million, and other revenue.

Finally, in Staff/800, witness Rose Anderson provides analysis of the Company's use of the Aurora production cost model, including testimony on model validation, system balancing sales, coal fuel price tiers, increased wheeling costs, and gas startup costs.

Q. Has Staff proposed any adjustments?

A. Yes. Staff's adjustments are summarized in confidential Figure 3 above, and as follows:

1. An adjustment to the EIM GHG benefit forecast, as detailed in Staff/100, Issue 2, part 2, representing a **[BEGIN CONFIDENTIAL]** [redacted] **[BEGIN CONFIDENTIAL]** decrease in NPC on a system-wide basis, or approximately **[BEGIN CONFIDENTIAL]** [redacted] **[BEGIN CONFIDENTIAL]** decrease on an Oregon-allocated basis.
2. An adjustment to remove the Company's proposed change to the DA/RT price adder, as detailed in Staff/200, Issue 2, representing a $20 million decrease in NPC on a system-wide basis, or $5.2 million decrease on an Oregon-allocated basis.
3. An adjustment to reverse the Company's proposed market caps methodology change, presented in Staff/300, Issue 1, instead continuing to use the "third quartile of averages" method for the 2023 TAM, resulting in a $22.7 million decrease in system-wide NPC, or $5.9 million decrease in Oregon-allocated NPV.
4. An adjustment to the Company's EIM transfer benefits forecast detailed in Staff/300, Issue 2, resulting in a $33.4 million decrease in system-wide NPV, or $8.7 million decrease in NPV on an Oregon-allocated basis.
5. An adjustment to Production Tax Credit rate used in the Company's forecast, detailed in Staff/400, Issue 1, resulting in a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** decrease in

system-wide NPV, or **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** decrease in NPV on an Oregon-allocated basis.

6. An adjustment to the Company's QF forecast to reflect a historic trend of over forecasting these costs. This adjustment results in a **[BEGIN CONFIDENTIAL]** [redacted] **[BEGIN CONFIDENTIAL]** decrease in NPC on a system-wide basis, or **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** decrease in Oregon-allocated QF costs, as explained in Staff/400, Issue 3.
7. An adjustment to remove the Company's proposed change to its methodology for forecasting maintenance outages, resulting in a $13.9 million decrease in NPC on a system-wide basis, or $3.6 million decrease to NPC on an Oregon-basis, as detailed in Staff/500, Issue 1.
8. An adjustment to remove the Company's proposed modeling change for summer generation thermal attributes, resulting in a $23.8 million decrease in NPC on a system-wide basis, or $6.2 million decrease to NPC on an Oregon-basis, as detailed in Staff/500, Issue 2.
9. A reduction in allowable expenses relating to the Naughton CSA, resulting in a $1.8 million decrease in NPC on a system-wide basis, or $0.5 million decrease to NPC on an Oregon-basis, as detailed in Staff/600, Issue 1.
10. A reduction in the Company's TAM expense of $50 thousand on an Oregon-allocated basis, to reflect shortcomings in the Company's Huntington analysis, as detailed in Staff/600, Issue 5.

11. A reduction in the Company's TAM expense of $50 thousand on an Oregon-allocated basis, as an incentive to encourage PacifiCorp's adherence to the Commission's requirements regarding, and development of more creative scenarios for, the economic cycling follow-up study, as detailed in Staff/600, Issue 6.
12. A reduction in the Company's TAM expense of $50 thousand on an Oregon-allocated basis, as an incentive to encourage PacifiCorp's care in complying with reporting requirements imposed by the Commission, as detailed in Staff/600, Issue 7.

Q. Has Staff made any other recommendations?

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

1. Provide information, testimony, and a workshop on its participation in the California Independent System Operation Extended Day-Ahead market (CAISO EDAM), beginning in advance of the 2024 TAM filing, as detailed in Staff/100, Issue 2, part 1.
2. Propose a forward-looking way to forecast off-system sales in future TAM proceedings, detailed in Staff/300, Issue 1.
3. Include a discussion of how its EIM transfer benefits models perform in its next TAM filing, detailed in Staff/300, Issue 2.
4. Provide additional details on CSAs, as explained in Staff/600, Issue 2.
5. Provide additional certain analysis in future updates to the Jim Bridger Long Term Fueling Plan, as explained in Staff/600, Issue 4.

6. Provide a 'backcast' model validation run in PacifiCorp's 2023 Power Cost Adjustment Mechanism filing PCAM, as detailed in Staff/800, Issue 1.

Q. Are there any issues on which Staff may make a recommendation at a later point?

A. Yes. Staff reserves the right to make recommendations on the following issues in rebuttal testimony:

1. Regulation reserve requirement. On May 10th, 2022, PacifiCorp filed a notice that it had made an error in the costs filed relating to the amount for regulation reserve requirement. As explained in Staff/500, Issue 3, Staff is unable to determine whether an adjustment is warranted to the Company's proposed $17.58 million cost increase in this filing.
2. Given that the data and analysis Ordered by the Commission in Order No. 21-279 on the Company's QF forecast had not yet been filed at the time of writing, Staff will review this issue further in rebuttal testimony.
3. Finally, Staff reserves the right to respond to issues raised by other parties in this proceeding, including the proposal of related adjustments in rebuttal testimony.

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 June 22, 2022. The Company will provide two further updates to the OFPC in the November indicative update on November 8, 2022, and the November final update on November 15, 2022.

ISSUE 1. COMPLIANCE WITH PRIOR TAM ORDERS AND TAM GUIDELINES

Q. What were the compliance implications of the 2022 TAM order?

A. In Order No. 21-379, the Commission included several provisions that required further action by the Company. Under Order No. 21-379, PacifiCorp is required to do the following:

- Facilitate qualified persons having more access to the Coal Supply Agreements (CSAs) and mine plans than was provided in the 2022 TAM;[19]
- Provide additional explanatory materials to support future CSA review;[20] and respect the general expectations detailed by the Commission regarding the types of analyses should be conducted to support future CSA review;[21]
- Carry out a follow-up economic cycling study;[22]
- Report four years of data on various pricing tiers for coal plant;[23]
- Update and file the Jim Bridger Long Term Fuel Plan document in the 2023 TAM incorporating the Commission's feedback in the 2023 TAM[24] by April 15th 2022;[25]
- Present analysis on the costs and benefits of pursuing Huntington's **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**;

19 Order No. 21-379, p. 4.
20 Order No. 21-379, p. 5.
21 Order No. 21-379, p. 6.
22 Order No. 21-379, p. 9.
23 Order No. 21-379, p. 12.
24 Order No. 21-379, p. 14.
25 Order No. 22-065, p. 5.

- Update a table with 2021 data, and address the question of why PacifiCorp has continued to over-forecast QFs in recent years;[26]
- Investigate whether a category of old, non-wind QFs are skewing the forecast, and address how it can improve the accuracy of its QF forecast, if the forecast error continues in 2021;[27] and
- File the 2023 TAM on March 1, 2022.[28]

Q. Has the Company facilitated qualified persons to have more access to the CSAs and mine plans than was provided in the 2022 TAM?

A. Yes. Staff is unaware of any parties that have been unable to review, or that have had undue restrictions imposed on their viewing of the Company's CSAs in this filing.

Q. Has Staff reviewed the explanatory materials and analysis provided by the Company to support the review of CSAs in this filing?

A. Yes. The Company's new CSA for Naughton, and associated Staff and Company analysis, is discussed in detail in Staff/600, Issue 1.

Q. Has PacifiCorp performed a follow-up economic cycling study?

A. Yes. The Company's follow-up economic cycling study was provided as part of its direct testimony.[29] The follow-up economic cycling study is analyzed in detail by Staff in Staff/600, Issue 6.

[26] Order No. 21-379, p. 38.
[27] Order No. 21-379, p. 38.
[28] Order No. 21-379, p. 43.
[29] PAC/100, Wilding/42.

Q. Has the Company reported the requested data on pricing tier for coal plant?

A. Yes. This data was provided with the Company's 15-day work papers. Staff has carried out a detailed analysis of the data provided in Staff/600, Issue 2.

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

A. PacifiCorp applied for an extension of this provision until the 2024 TAM, however its request was rejected by the Commission in Order No. 22-065.[30] PacifiCorp instead was instructed to provide the updated report by April 15, 2022, and it complied with the revised due date. The details of the Jim Bridger Long Term Fuel Plan are discussed in Staff/600, Issue 4.

Q. Has the Company presented analysis on the costs and benefits of pursuing Huntington's [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]?

A. Yes. Although the Company indicated in its initial filing that it intended to provide the requested analysis on April 15, 2022, the analysis was provided on April 28, 2022. Staff's detailed analysis of this subject is provided in Staff/600, Issue 5.

Q. Has the Company provided the requested data on QFs, and addressed the questions put forward by the Commission in Order No. 21-379?

A. No. At the time of writing the information had not yet been provided by the Company. The Company indicated in its initial testimony that the data

30 Order No. 22-065, p. 5.

would not be available until after PacifiCorp files the PCAM on May 15, 2022, and that it intended to provide the required information in its rebuttal filing.[31]

PacifiCorp's direct testimony stated that "preliminary analysis indicates that the variance may be associated with the forecasts for small Oregon QFs."[32] Unfortunately, although requested in advance by Staff, PacifiCorp was unable to provide any detail on its initial findings at a workshop between parties to this filing that was held on May 9, 2022.

Staff has recommended one adjustment to the QF forecast in Staff/400, Issue 3. Staff reserves the right to modify its adjustment or propose additional adjustments following the Company's provision of the required information.

Q. Did the Company file the 2023 TAM on March 1, 2022?

A. Yes. The Company filed the 2023 TAM on March 1, 2022, as directed by the Commission. The 2023 TAM was filed concurrently with a General Rate Case, which is docketed as UE 399.

Q. Were there any outstanding compliance obligations required of PacifiCorp based on the 2021 TAM order? Please explain.

A. During the filing and settlement of the 2021 TAM, PacifiCorp informed parties and the Commission that it expected to transition to the AURORA

[31] PAC/100, Wilding/53.
[32] PAC/100, Wilding/53.

model to forecast NPC in the 2022 TAM filing.[33] PacifiCorp's transition was delayed due to the COVID-19 pandemic.[34] As a result, several provisions in Order No. 20-392 required action by the Company in this filing. They include:

- Holding a workshop on the transition from GRID to AURORA;
- Providing Aurora licenses and other inputs to Parties;
- Providing one model run per intervenor;
- Removing the "must run" setting as part of the transition to AURORA;
- Performing an informational model run that removes any operational constraints related different coal supply agreement (CSA) assumptions; and
- Providing additional information on CSAs.

Q. Has the Company held a workshop on the transition from GRID to AURORA?

A. Yes. The Company held a workshop with Staff and intervenors on February 15, 2022. PacifiCorp has also included the presentation given at the workshop on the record in this filing.[35]

Q. Has the Company provided Aurora licenses and other inputs to Parties?

33 UE 375 - Stipulating Parties/100, Webb, Gibbens, Jenks, Higgins, Kaufman, Burgess, Reed, Dickman/1, lines 13 - 14.
34 PAC/100, Webb/23, lines 12 - 17.
35 Confidential Exhibit PAC/105.

A. Staff has an existing Aurora license, and as such did not request a license from the Company. Staff is aware that PacifiCorp provided an Aurora license on behalf of at least one intervenor in this case.

Q. Has the Company provided a model run per intervenor?

A. Staff did request that the Company perform a back cast of PacifiCorp's NVPC in historic years, created using the AURORA model, with forecasted inputs substituted for actual data. In response, PacifiCorp indicated that:

> *building the input data for years for which an AURORA database does not exist is extremely burdensome, and PacifiCorp is unable to conduct this requested analysis .. this process would take many months.*[36]

Staff is aware that the Stipulation underlying the 2020 order allows for PacifiCorp to refuse such a request if it is unreasonable or the Company does not have reasonable time to complete the request during the proceeding. In Staff/800, Issue 1, Staff makes a recommendation regarding model validation using Aurora.

Staff is not aware of any party that has been denied an Aurora model run by the Company. Staff expects that any party who has not been able to receive a model run from the Company will raise this issue in its opening testimony.

Q. Did the Company comply with the Order No. 20-392 as it relates to coal issues?

---

[36] Staff/102, Enright/13, PAC Response to Staff DR 104.

A. Generally, yes. In the 2021 TAM the Company removed the "must run" constraint, provided an informational model run, provided additional information on new CSAs, and addressed the reasonableness of modeling minimum take provisions.[37] Staff expressed concerns about the implementation of the informational model run and minimum take assumptions in the 2021 TAM, which informed the record resulting in Order No. 21-379, as discussed above. Staff has continued its review of coal related issues in this docket, as presented in Staff/600.

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

A. Staff has reviewed the Company's filing and finds that they have thus far complied with the TAM Guidelines in the 2023 TAM. 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. However in its initial filing, the Company has complied with the Commission directive.

Q. Does Staff have any recommendations regarding the TAM Guidelines?

A. Not in this case. Staff notes that in PacifiCorp's General Rate Case. Docket No. UE 399, that PacifiCorp is proposing changes to the TAM guidelines to come into effect with the 2024 TAM forecast filing. Staff intends to provide testimony on this matter in the GRC proceeding.

---

[37] Staff/100, Enright/15 - 16.

ISSUE 2. EIM BENEFITS

Q. How are EIM benefits reflected in rates?

A. Forecasted EIM benefits are applied as an offset to power costs, reducing the rates paid by customers.

Q. Please describe how EIM benefits are forecasted by PacifiCorp.

A. Each of Oregon's investor-owned utilities has taken a different approach to forecasting its EIM benefits, to best fit their differing resource mix and NPC forecasting models. In PacifiCorp's case, it has divided EIM benefits into three categories in the TAM forecast: energy transfer benefits, GHG benefits, and flex reserve benefits.

As the benefits of the Company's EIM participation cannot be forecasted by the Aurora model, they are instead forecasted using separate models. To date, Staff, intervenors, and PacifiCorp have not agreed on an enduring model(s) for forecasting EIM benefits.

Q. Please provide an overview of the three types of EIM benefits that are forecasted by PacifiCorp.

A. GHG benefits are measured in dollars and are calculated as the Company's historic GHG revenue from EIM, less the resulting compliance costs paid to the California Air Resources Board (CARB), with a growth factor applied. The 2022 TAM includes **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in GHG benefits on a system wide basis, which is a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** from the 2022 TAM. The Company's GHG benefit forecast is discussed later in this section.

Energy transfer benefits are also measured in dollars and forecasted using a regression model that uses historic energy transfer benefits and forecasted market variables to predict a future EIM benefit. The 2023 TAM includes **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in energy transfer benefits on a system wide basis, a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** from the 2022 TAM. The Company's energy transfer benefits forecast is analyzed in the testimony of Staff witness Dr. Dlouhy in Staff/300, Issue 2.

Flex reserve benefits are measured in a MW reduction to the Company's reserve requirement as a result of its EIM participation. The MW benefit is equal to the average difference between the Company's pre-EIM reserve requirement, and its reserve requirement once participating in EIM, and is calculated using historic CAISO values. Although flex reserve benefits do not have an assigned dollar value, they provide value to customers through the TAM by reducing the reserve requirement in the GRID model. The Company's flex reserve benefits forecast is analyzed in the testimony of Staff witness Mr. Fjeldheim in Staff/500, Issue 3.

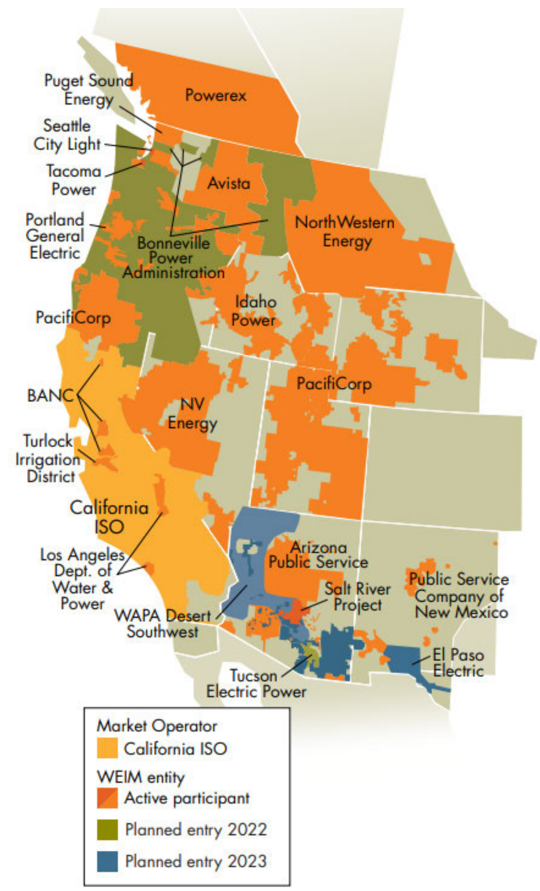
Q. Please provide an overview of your testimony related to EIM benefits.

A. In my testimony, I will first provide a short overview of the three categories of EIM benefits forecasted by PacifiCorp, including references to where elements of the Company's forecast have been analyzed by Staff. I will then provide a short overview of changes in the EIM over the past year, my analysis of EIM costs, and my recommendations regarding the Company's forecast of GHG benefits.

Issue 2. Part 1 - EIM 2022 Update

Q. What has changed in the EIM over the past year?

A. The EIM has expanded over the past year with the addition of five new utilities: NorthWestern Energy in 2021; Avista Utilities and Tacoma Power in March 2022;[38] and Tucson Electric Power and Bonneville Power Administration in May 2022.



2021 was the most successful year to date for EIM entities, with cumulative benefits of $739 million in the year,[39] reaching a new milestone of $2 billion in cumulative

[38] Western Energy Imbalance Market News Release March 2, 2022. See: https://www.westerneim.com/Documents/Two-More-Utilities-Join-Western-Energy-Imbalance-Market.pdf.

[39] Western Energy Imbalance Market News Release January 31, 2022. See: https://www.westerneim.com/Documents/Western-EIM-achieves-record-setting-739-million-in-benefits-for-2021.pdf.

benefits in February 2022. This is less than two years after the first major milestone of $1 billion was achieved.[40]

The EIM footprint now includes portions of Arizona, California, Idaho, Nevada, Oregon, Utah, Washington, Wyoming, New Mexico, and the Canadian province of British Columbia. Further expansion of the EIM market is planned for 2023, at which point EIM participants are projected to represent 79 percent of the load within the Western Electricity Coordinating Council (WECC).[41]

Q. Is an Extended Day Ahead Market (EDAM) still being considered?

A. Yes. During the first three months of 2022 intensive stakeholder meetings took place to deal with important market issues. This culminated in the CAISO publishing a straw proposal in late April 2022 describing key design elements of the day-ahead market as well as areas requiring additional work and stakeholder input.[42]

The CAISO will take comments on the market design through early June, and will continue working with stakeholders across the West, aiming to finalize the market's design by the end of 2022.

Q. What are the implications of the proposed EDAM for this filing, or future TAM filings?

---

40 Western Energy Imbalance Market News Release April 21, 2022. See: https://www.westerneim.com/Documents/Western-Energy-Imbalance-Market-Surpasses-2-Billion-in-Benefits.pdf.

41 Western Energy Imbalance Market Fact Sheet April 2022. See: https://www.westerneim.com/Documents/WEIM-2-Billion-in-Benefits-Fact-Sheet.pdf.

42 CAISO day-ahead market enhancements. See: https://stakeholdercenter.caiso.com/StakeholderInitiatives/Day-ahead-market-enhancements.

A. Current plans call for EDAM implementation testing in 2023 and onboarding the first set of EDAM participants in early 2024.[43] PacifiCorp has been an active participant in stakeholder meetings regarding the EDAM to date and was the first member to join CAISO in the EIM.

Q. Does Staff have any recommendations regarding the EDAM?

A. Yes. In anticipation of PacifiCorp's likely participation in the EDAM in 2024, Staff recommends that the Commission require PacifiCorp to provide the following to Staff and parties:

a. Quarterly updates on the progress of the EDAM project, beginning in December 2022, including details of PacifiCorp's involvement in the stakeholder process, the expected implementation timelines for EDAM, and detail of PacifiCorp's intentions and timeline for EDAM participation.

b. Testimony in the 2024 TAM detailing the benefits the Company expects to accrue from its EDAM participation, and how such benefits will be reflected in customer rates.

c. Testimony in the 2024 TAM regarding any costs the Company requests recovery for in relation to its EDAM participation, including an itemized breakdown of costs, identifying both variable and fixed costs separately, and including detail of the basis for the Company's cost forecast.

---

[43] Western Energy Imbalance Market News Release April 21, 2022. See: https://www.westerneim.com/Documents/Western-Energy-Imbalance-Market-Surpasses-2-Billion-in-Benefits.pdf.

d. A workshop held prior to the filing of the 2024 TAM, in which PacifiCorp should present on the issues detailed at (b) above.

Issue 2. Part 2 – GHG Benefits

Q. How do Oregon's IOUs earn GHG benefits in EIM?

A. Energy exported to California to meet load in that state is subject to California's GHG obligation. The EIM provides GHG revenue to compensate generators both inside and outside of California for their compliance costs. Oregon's IOUs benefit when their GHG revenue in EIM is excess to their GHG compliance costs.

Q. How, and in what situations, do Oregon's IOUs earn GHG revenue?

A IOUs outside California may include a "GHG bid adder" when submitting bids to EIM for thermal units. The GHG bid adder is calculated based on the price of a California Carbon Allowance (CCA) and reflects the IOU's potential GHG compliance cost for power exported to California. The GHG bid adder allows CAISO's market optimization to identify the least cost dispatch to serve California load (considering GHG compliance costs), and the least cost dispatch to serve load within the rest of the EIM (absent GHG compliance costs).[44]

If CAISO determines that GHG emitting generation at a node within PacifiCorp's BAs served California load, both GHG emitting and non-GHG

[44] The GHG bid adder essentially forces GHG emitting generators down the merit stack for California purposes.

emitting resources generating at that node will be paid the GHG bid adder of the marginal unit.[45]

Q. Does all GHG emitting generation in EIM incur a GHG compliance obligation with CARB?

A. No. Although the Company receives GHG revenue for all incremental generation above its base schedule, it incurs a GHG compliance obligation only on the portion of the GHG-emitting generation “deemed delivered” to California (with PacifiCorp’s hydro generation incurring no compliance obligation, even when deemed delivered to California.

Take for instance an hour in which the Company was selling 100 MWh at an EIM node with a GHG price adder, and 10 MWh of the EIM sale was deemed delivered to California. In this case, PacifiCorp would receive the GHG price adder for 100MWh of generation, and incur a compliance obligation for only the portion of the 10MWh of generation that was provided by a GHG-emitting resource.

Q. Please describe how PacifiCorp forecasts its EIM GHG benefits.

A. There are two steps to the Company’s forecast. PacifiCorp first calculates its historic GHG benefits for hydro units and thermal units. The second step is to create a naïve forecast of future benefits, with adjustments for growth in GHG prices and seasonal shaping.

---

[45] These costs are allocated to California demand. FERC Docket No. AD20-14-000, “Carbon Pricing in Organized Wholesale Electricity Markets”, https://www.ferc.gov/sites/default/files/2020- 09/Panel-3-Group-1-Rothleder-CAISO-Comments.pdf.

Q. How has this issue been dealt with in previous TAM filings?

A. Staff provided detailed testimony and analysis in the 2021 TAM filing regarding its concerns with PacifiCorp's forecast.[46]

Staff ultimately made three recommendations to improve the Company's forecast:

a. A correction to the growth factor applied in the Company's model,

b. The use of a longer historic period as the basis for the GHG benefits forecast, and

c. The application of a CCA growth factor not only to GHG benefits from hydro units, but also to the GHG benefits and GHG compliance costs of thermal units, based on evidence of the guaranteed increases in CCA prices under the California Cap-and-trade laws.[47]

Q. Were Staff's recommendations implemented in the 2021 TAM?

A. The Company accepted all of Staff's three recommendations in its reply testimony for the 2021 TAM,[48] however it stated that it was accepting Staff's third recommendation on a non-precedential basis in order to further research the topic, and provide a revised proposal in the 2023 TAM filing.[49]

Q. Was Staff's third recommendation implemented in the current filing, or was a revised proposal provided by PacifiCorp?

---

[46] Docket No. UE 390, Staff/100, Enright/27 - 39.

[47] As detailed by Staff in Docket No. UE 390, GHG Allowance prices are designed to increase each year. This occurs because auction reserve prices ratchet up each year, while the cap on emission reduces, creating scarcity in the market. CCA auction reserve prices are increased annually by five percent plus the rate of inflation, in accordance with 95911(c)(3) of the California Regulation.

[48] Docket No. UE 390, PAC/400, Staples/83, lines 5, 16 - 17.

[49] Docket No. UE 390, PAC/400, Staples/83, lines 16 - 18.

A. No . Staff's third recommendation was not implemented, nor did PacifiCorp provide a revised proposal in this filing. Staff reached out to the Company regarding this matter and learned that the Company had not applied the growth rate as recommended by Staff.[50] The Company added to its response:

> *The data collection and analysis is ongoing and has not yet been completed. PacifiCorp will have the analysis and proposed revisions completed prior to the reply testimony / net power costs (NPC) update filing in June 2022. PacifiCorp will either accept Public Utility Commission of Oregon (OPUC) staff's changes or provide testimony explaining why PacifiCorp has not adopted OPUC staff's changes*.[51]

Q. What is Staff's recommendation regarding this issue?

A. Staff stands by its recommendation in Docket No. UE 390, that a CCA growth factor should be applied not only to GHG benefits from hydro units, but also to the GHG benefits and GHG compliance costs of thermal units, resulting in a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[52] reduction in NPC on a system-wide basis, and a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** reduction on an Oregon-basis.

---

[50] PacifiCorp's response to Staff DR 38, section (a), part 2.

[51] PacifiCorp's response to Staff DR 38, section (b).

[52] Staff calculated value based on GHG benefit model with updated historic data through **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. See Exhibit Staff/102, Enright/8 - 12, PacifiCorp's Confidential first supplemental response to Staff DR 37.

Staff recommends that the Commission order PacifiCorp to integrate this change into its GHG benefit forecast given that it supported by thorough testimony and by Staff in Docket No. UE 390, which proved that the exclusion of CCA price growth in the calculation of GHG benefits for thermal generators was both an inaccurate representation of the benefit accruing to PacifiCorp, and unduly removed a financial benefit that act as an offset to customer rates.[53] Staff believes that an instruction from the Commission is appropriate here to avoid incenting the utility to delay the implementation of logical modeling changes that benefit customers, and further, to avoid forcing Staff and parties to replay past discovery, testimony, and analysis in each TAM filing.

Q. Does this conclude your testimony?

A. Yes.

---

[53] Docket No. UE 390, Staff/100, Enright/25 - 39.

CASE: UE 400
WITNESS: MOYA ENRIGHT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualifications Statement

May 25, 2022

WITNESS QUALIFICATIONS STATEMENT

NAME:	Moya Enright
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Economist Energy Rates Finance and Audit Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	Energy Risk Professional Certification, 2021. Global Association of Risk Professionals. M.Sc. Political Science, 2015. University of Amsterdam. M.Sc. Investment, Treasury and Banking, 2011. Dublin City University. B.A. International Business and Languages, 2008. Dublin City University through a joint curriculum with École Supérieure de Commerce de Montpellier.
EXPERIENCE:	Senior Utility and Energy Analyst at OPUC since January 2019. Energy Trader for Meridian Energy from 2015 to 2019. Meridian Energy is a power generator and retailer operating both in New Zealand and Australia. Trading and Operations Analyst at Tynagh Energy from 2011 to 2013. Tynagh Energy is an independent power producer operating in the Republic of Ireland. Senior Electricity Market Controller at EirGrid from 2008 to 2011. EirGrid is the Irish electricity Transmission System Operator. It operates the Single Electricity Market for the Republic of Ireland and Northern Ireland. Accounts Assistant roles from 2004 to 2008, including Audit Intern at KPMG in Northern Ireland.

CASE: UE 400
WITNESS: MOYA ENRIGHT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 102

Exhibits in Support
Of Opening Testimony

May 25, 2022

UE 400 / PacifiCorp
April 21, 2022
OPUC Data Request 32

OPUC Data Request 32

General - Regarding total Net Variable Power Cost:

(a) Please provide the total forecasted Net Variable Power Cost included in rates for each year from 2013 through 2022.

(b) Please provide the Company's total Net Variable Power Cost forecast for 2023 in US dollars based on the most recent filing.

(c) Please provide the total Net Variable Power Costs incurred in each year from 2013 through 2022.

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 32

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:

(a) Please refer to Confidential Attachment OPUC 32-1 which provides forecasted net power costs (NPC) included in rates for each year from 2013 through 2022.

(b) Please refer to Exhibit PAC\101 (Oregon-allocated NPC). Please also refer to the Company's responses to TAM Support Set 1 (concurrent), specifically confidential work paper "ORTAM23 NPC CONF".

(c) Please refer to Attachment OPUC 32-2 which provides copies of the Company's actual NPC (total company) for calendar years 2013 through 2015. Please refer to Confidential Attachment OPUC 32-3 which provides copies of the associated actual NPC (total company) mapping files for calendar year 2013 through 2015. Please refer to the Company's response to AWEC Data Request 001, specifically Attachment AWEC 001-1 and Confidential Attachment AWEC 001-2, which provide copies of the Company's actual NPC (total company) for calendar years 2016 through 2021. Please refer to the Company's response to AWEC Data Request 001,

UE 400 / PacifiCorp
April 21, 2022
OPUC Data Request 32

specifically Confidential Attachment AWEC 001-3 which provides copies of the associated actual NPC (total company) mapping files for calendar years 2016 through 2021. Please refer to the Company's response to AWEC Data Request 002 with regard to the Company's actual NPC (total company) for calendar year 2022.

Please refer to Confidential Attachment OPUC 32-4 which provides copies of the Company's Oregon power cost adjustment mechanism (PCAM) calculations. Note 1: 2021 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, 2022. The Company will supplement this response with 2021 data shortly thereafter. Note 2: 2022 data will not be available until after the Company's PCAM filing is submitted to the OPUC in mid-May 2023.

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.

Staff Exhibit

“Attachment to DR 32”

is filed in electronic format

Confidential Staff Exhibit

“Confidential Attachment to DR 32”

is filed in electronic format

UE 400 / PacifiCorp
April 22, 2022
OPUC Data Request 33

OPUC Data Request 33

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 2013 through 2022. 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 unit cost in US dollars for each resource type.

(b) Please provide a breakdown of the power resources included in the Company's 2023 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 unit cost in US dollars for each resource type.

(c) Please provide a breakdown of the actual power resources used by the Company for each year from 2013 through 2022. 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 unit 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 2022 as it becomes available.

Response to OPUC Data Request 33

UE 400 / PacifiCorp
April 22, 2022
OPUC Data Request 33

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:

(a) Please refer to the Confidential Attachment OPUC 33 which provides the final net power costs (NPC) reports from each Oregon transition adjustment mechanism (TAM) proceeding covering forecast years 2013 through 2022 (Docket UE-245 through Docket UE-390). 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).

(b) Please refer to the Company's responses to TAM Support Set 1 (concurrent), specifically confidential work paper "ORTAM23 NPC CONF", 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 32 subpart (c). 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.

Confidential Staff Exhibit

"Confidential Attachment to DR 33"

is filed in electronic format

UE 400 / PacifiCorp
April 20, 2022
OPUC Data Request 37

OPUC Data Request 37

EIM participation - Regarding the Company's EIM benefit forecast model(s):

(a) Please provide a copy of each of the Company's EIM benefit model(s) in electronic workbook format, with all cells and formulas intact.

(b) For each model provided, please provide a narrative explanation of how the model works.

(c) Please indicate where the EIM benefit amount can be seen in each model, providing a specific reference to the cell and tab in which it appears in each workbook.

(d) Please indicate where the EIM benefit amount shown in response to subpart (c) appears in the Company's filing, providing a specific reference to the cell and tab in which it appears in each workbook.

Response to OPUC Data Request 37

For the Company's 2023 transition adjustment mechanism (TAM) for calendar year 2023:

(a) Please refer to Confidential Attachment OPUC 37.

(b) Each model follows the descriptions laid out in Public Utility Commission of Oregon (OPUC) staff's Opening Testimony in the Company's 2022 TAM, Docket UE-390, specifically the Opening Testimony of OPUC staff witness, Dr. Curtis Dlouhy, Exhibit Staff\ 800 and incorporates all proposed recommendations. Here is a summary of the four models:

   i. The "PACE Export Model" uses a double log econometric model using a log transformation of power price, a log transformation of gas price, and two dummy variables ("Enbridge" and "CAISO-PAC" bilateral) to predict a log transformation of margins.

   ii. The "PACW Export Model" uses the independent variables gas price, power price and the "Enbridge" dummy variable to predict margins. Gas price and power prices are modified using a quadratic transformation. Margins are modified using a square root function. The Company continues to use this model specification because the goodness of fit as it is still an improvement over the log-log formulation.

UE 400 / PacifiCorp
April 20, 2022
OPUC Data Request 37

iii. The "PACE Import Model" uses a double log econometric model using a log transformation of power price, the total transmission capacity, and the total capacity from operating and planned solar resources in the California Independent System Operator (CAISO) to predict a log transformation of margins.

iv. The "PACW Import Model" uses a double log econometric model using a log transformation of power price, the total transmission capacity, and the total capacity from operating and planned solar resources in CAISO to predict a log transformation of margins.

(c) Please refer to Confidential Attachment OPUC 37. The energy imbalance market (EIM) benefit forecast amount for 2023 is provided in file "EIMForecast.csv", tab "EIMForecast", cellsT50 through T61.

(d) Please refer to the Company's response to TAM Support Set 1 (concurrent work papers), specifically confidential work paper "ORTAM23 NPC CONF.xlsx", tab "EIM", cells D2 through O2.

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 400 / PacifiCorp
May 17, 2022
OPUC Data Request 37 – 1st Revised / 1st Supplemental

OPUC Data Request 37

EIM participation - Regarding the Company's EIM benefit forecast model(s):

(a) Please provide a copy of each of the Company's EIM benefit model(s) in electronic workbook format, with all cells and formulas intact.

(b) For each model provided, please provide a narrative explanation of how the model works.

(c) Please indicate where the EIM benefit amount can be seen in each model, providing a specific reference to the cell and tab in which it appears in each workbook.

(d) Please indicate where the EIM benefit amount shown in response to subpart (c) appears in the Company's filing, providing a specific reference to the cell and tab in which it appears in each workbook.

1st Revised / 1st Supplemental Response to OPUC Data Request 37

Further to the Company's response to OPUC Data Request 37 dated April 20, 2022, the Company provides the following (1) revised, and (2) supplemental information:

(1) Upon further review, the Company became aware that the energy imbalance market (EIM) benefits model inputs and outputs provided with the Company's original response to OPUC Data Request 37, specifically Confidential Attachment OPUC 37, provided incorrect versions of the model inputs and outputs. Please refer to Confidential Attachment OPUC 37 1st Revised which replaces, in its entirety, the contents of Confidential Attachment OPUC 37. Note: the Company's original narrative response to OPUC Data Request 37 remains unchanged and valid. However, the correct supporting model inputs and outputs are provided in Confidential Attachment OPUC 37 1st Revised.

(2) In addition, on May 10, 2022, Public Utility Commission of Oregon (OPUC) staff advised that as well as requesting information on EIM benefits, OPUC staff intended OPUC Data Request 37 to also request information on greenhouse gas (GHG) benefits. Based on this additional request, the Company provides the following supplemental information related to GHG benefits:

   (a) Please refer to Confidential Attachment OPUC 37-1 1st Supplemental which provides the GHG Benefit Forecast. One change was made between the GHG Benefit Forecast provided in Confidential Attachment OPUC 37-

1 1st Supplemental and the GHG Benefit Forecast that was provided in the 2022 transition adjustment mechanism (TAM), Docket UE-390. Between the months of April 1, 2021 and December 31, 2021, GHG benefit actuals were formed from the emissions factors that expired on April 1, 2020. Note: emission factors are used to construct the GHG Bid Price. Please refer to Confidential Attachment OPUC 37-2 1st Supplemental which provides a comparison of before and after the above referenced change / update, specifically tab "GHG Benefits Compare". The GHG Bid Prices used to generate the GHG benefits are included in tab "GHG Bid Prices".

(b) The GHG Benefit Forecast is constructed by averaging GHG benefits recorded over the past three years. The methodology then applies seasonal weights to shape the forecast. Future benefits are marked up relative to the Company's forecasted inflation rate. GHG benefits attributed to hydro exports received an additional 5 percent growth rate for forecasting future years.

(c) The total GHG Benefit Forecast is provided in cell F98 on tab "GHG Benefits" of Confidential Attachment OPUC 37-1 1st Supplemental.

(d) Please refer to the Company's response to TAM Support Set 1 (concurrent work papers), specifically confidential work paper "ORTAM23 NPC CONF.xlsx", tab "EIM", cells D3 through O3 for GHG Benefit Forecast values

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.

Confidential Staff Exhibit

“Confidential Attachment to DR 37”

is filed in electronic format

UE 400 / PacifiCorp
May 20, 2022
OPUC Data Request 104

OPUC Data Request 104

AURORA model – For each calendar year from 2019 through 2021 please provide:

(a) A backcast of PacifiCorp's Net Variable Power Costs (NVPC), created using the AURORA model, with forecasted inputs substituted for actual data. In this response please include:

i. The total AURORA-modeled Net Variable Power Costs in US dollars.
ii. Total volume of power modelled as being generated by each resource type (e.g. wind, market purchases, solar natural gas).
iii. Total cost in US dollars of each resource type.
iv. Average per unit 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. Please provide the requested data in electronic workbook format with all cells and formulas intact.

(b) If the Company is unable to provide the response requested in subpart (a), please provide a narrative explanation of explain why not.

Response to OPUC Data Request 104

The Company objects to this request as overly broad, unduly burdensome, requiring the Company to develop information or prepare a study, lacking a high degree of relevance to the proceeding, and not reasonably calculated to lead to the discovery of admissible information. Without waiving the foregoing objection, PacifiCorp responds as follows:

As PacifiCorp identified in its response to OPUC Data Request 16, and further explained in a discussion with Public Utility Commission of Oregon (OPUC) staff held on May 13, 2022, building the input data for years for which an AURORA database does not exist is extremely burdensome, and PacifiCorp is unable to conduct this requested analysis. As identified in the discussion with OPUC staff, this process would take many months.

CASE: UE 400
WITNESS: HEATHER COHEN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 200

Opening Testimony

May 25, 2022

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

A. My name is Heather Cohen. I am a Senior Utility Analyst employed in the Energy Rates and Accounting 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 qualification 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 2023 Transition Adjustment Mechanism (TAM) filing, UE 400.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1, TRAPPED ENERGY AND EMERGENCY PURCHASES

Q. What is trapped energy and how does the Company value it?

A. Trapped energy is a modeling concept that represents generation that is unable to be used to serve load due to transmission constraints. Previously the Company valued trapped energy at 75 percent of market prices. The Company claims that this overstates sales revenue since the concept of trapped energy does not exist in operations.[1] In reality, the Company claims the value of trapped energy should be zero.[2] When Staff inquired why the Company does not simply value trapped energy at zero, the Company responded that the AURORA model could not decrease the generation any lower than any of the plants' minimum operational levels, requiring trapped energy to have a value.[3] The Company is proposing to reduce its value to 25 percent of market value, which has an impact of $181,945 in lowered sale revenue, or approximately $47 thousand Oregon dollars.[4]

FIGURE 1: TRAPPED ENERGY REVENUES

[redacted]

[1] PAC/100, Wilding, 37.
[2] Ibid.
[3] Staff/202, Cohen/7, PAC response to Staff DR 8.
[4] PAC/107, Wilding/1.

Staff replicated the Company's step log in Figure 2 below to better depict the dollar impact (Total Company and Oregon) of each step or change to the model. Trapped energy is step 7 below.

FIGURE 2: STEP LOG

[redacted]

[redacted]

[redacted]

Q. How is trapped energy modeled in AURORA?

A. Trapped energy sales are listed per hub and date and discounted by a certain rate. Accordingly, there are two hubs that have trapped energy in this period, Colorado and Mona, with the [redacted] discount in prior TAMs.[5]

[5] PAC Confidential Concurrent Workpapers SL07 Trapped Energy NPC ORTAM CY2023 CONF.xlsx.

FIGURE 3: TRAPPED ENERGY VALUED AT 25 AND 75 PERCENT

[redacted]

[redacted]

[redacted]

These amounts are calculated as the [redacted] for the month. For example, see the below figure of the Colorado trapped energy calculation.

FIGURE 4: COLORADO TRAPPED ENERGY JULY 2023

[redacted]

[redacted]

[redacted]

Q. Has there been any variation in trapped energy in the switch from GRID to AURORA?

A. While there were differences in overall revenue numbers and megawatt hours, the dollars per megawatts changed minimally.[6]

FIGURE 5: TRAPPED ENERGY 2022 AND 2023

[redacted]

[redacted]

[redacted]

When asked about the year-to-year increase, the Company points to the "inherent differences between the dispatch of thermal resources" in the two models.[7] Accordingly, the thermal generation level is al[redacted] in 2023 than 2022.[8]

Q. What are emergency purchases?

A. Similar to trapped energy, emergency purchases are a modeling construct used when the model has no other method to satisfy the load obligation due to modeling constraints or when the emergency purchase price is less than the cost of an alternative solution.[9] Emergency purchases are valued at 125 percent of market in AURORA, although these are conservative

[6] PAC Confidential Workpapers ORTAM 23 NPC CONF, ORTAM 22 NPC CONF.xlsx.
[7] Staff/203, Cohen/1, PAC Confidential response to Staff DR 10.
[8] PAC/100, Wilding, 31.
[9] PAC/100, Wilding, 44.

assumptions unlikely to reflect actual emergency purchase needs in operation. These purchases ensure the model meets its reliability target of no unserved load.[10]

Q. How are emergency purchases modeled in AURORA?

A. The majority of these purchases take place at Jim Bridger and Clover in the summer months, using a discount of 125 percent.

FIGURE 6: EMERGENCY PURCHASES

[redacted]

These amounts are calculated by taking [redacted]. For example, Jim Bridger's emergency purchases would be [redacted] in July 2023.

Q. Has there been any variation in emergency purchases in the switch from GRID to AURORA?

[10] PAC/100, Wilding, 44.

A. Yes, emergency purchases have increased over [redacted] in dollars and almost [redacted] in megawatt hours, and from [redacted] in dollars per megawatt hour. In several scenarios (Must Run, Coal Cycling Turned On), there is an increase in emergency purchases due to decreased gas and curtailed VER (Variable Energy Resources) generation, scenarios which are described as unrealistic by the Company.[11]

Staff submitted several data requests regarding the increase in Emergency Purchases projected in the summer months. The Company has attributed these forecast purchases to serving higher summertime load.[12] Staff has no adjustment at this time.

<u>FIGURE 7: EMERGENCY PURCHASES 2022-2023</u>

[redacted]

[redacted]

[redacted]

[11] PAC/100, Wilding, 49.
[12] Staff/203, Cohen/2, PAC Confidential response to Staff DR 84.

ISSUE 2, DA/RT

Q. What exactly is DA/RT?

A. According to the Company, the Day Ahead Real Time (DA/RT) adjustment is used to correct price volatility resulting from purchases made by the Company during higher-than-average price periods and sold more during lower-than average price periods.[13]

Q. What is the history of the DA/RT adjustment?

A. The DA/RT adjustment or adder has been a highly contentious issue since it was approved in the 2016 TAM.[14] Staff has continually argued that the adder distorts market prices, creating an artificial cushion for the Company by forcing purchase prices higher and sales prices lower in the model than in actual transactions.[15] Staff was hopeful that the change to AURORA would eliminate the need for DA/RT as it was a GRID deficiency, but the Company has testified there is no AURORA feature that would address this.[16] In fact, the Company is proposing to increase NPC by $20 million Total Company and $5.2 million Oregon dollars in order to change the adder from price-based to a percentage of prices to "better capture intra-monthly variability".[17]

Q. Please describe Staff's analysis of this issue.

[13] PAC/100, Wilding, 20.
[14] UE 375, Staff/200, Enright/50.
[15] UE 375, Staff/200, Enright/52.
[16] PAC/100, Wilding/22.

A. Staff sent over ten multipart data requests on this issue, putting together a step-by-step description of how the adder works based on Company workpapers.[18] Staff's confidential data request 92 documents the adder steps, the most contentious of which is excerpted below.[19]

FIGURE 8: DA/RT ADDER STEP

[redacted]

[redacted]

[redacted]

[18] PAC Confidential Workpapers\OR UE-400 CONF 5-BD Work Papers\Generic\GNw DA-RT Price Adder (2112) (CY2020-2023) CONF.xlsx Adders tab cells C250-Z261.
[19] Staff/203, Cohen/4-6, PAC Confidential response to Staff DR 92.

[redacted][20]

FIGURE 9: DA/RT ADDER FOUR CORNERS LLH

[redacted]

[redacted][21]

[20] Ibid.
[21] Ibid.

[redacted]

FIGURE 10: DA/RT ADDER FOUR CORNERS LLH GRID INPUT

[redacted]

Q. How does this impact the overall value?

A. [redacted][23]

[22] PAC Confidential Workpapers\OR UE-400 CONF 5-BD Work Papers\Generic\GNw_DA-RT Price Adder (2112) (CY2020-2023) CONF.xlsx 2112 OFPC (2020-2023) tab.
[23] Ibid.

FIGURE 11: OFPC PLUS DA/RT ADDER

[redacted]

Q. Did Staff find any other examples of artificial losses?

A. [redacted]

FIGURE 12: DA/RT ARTIFICIAL LOSSES IN COB, FOUR CORNERS

[redacted]

[24] See Staff Exhibit 204 Confidential DA-RT Adder workbook.xls sourced from PAC Confidential Workpapers\OR UE-400 CONF 5-BD Work Papers\Generic\GNw DA-RT Price Adder (2112) (CY2020-2023) CONF.xlsx Adders tab (electronic spreadsheet).

[redacted]

FIGURE 13: OFPC VS MODELED PRICE

[redacted]

Q. Does Staff have an adjustment?

A. Yes. Staff rejects the $5.2 million Oregon ($20 million Total Company) increase to NPC associated with DA/RT. Staff's adjustment relates to two elements of DA/RT:

1. Staff recommends rejecting the DA/RT modelling change proposed by PacifiCorp, which would allow it to calculate the DA/RT price adder as a percentage instead of a dollar value. While the Company's testimony claims the percentile change would better capture "intra-month volatility," the Company has not provided any evidence of this.

2. Moreover, the inherent bias in the DA/RT adder has not been corrected in AURORA. The Company describes the DA/RT adder as "prices which account for the historical price differences between the Company's purchases and

sales compared to the monthly average market prices,"[25] but this is not entirely accurate as the final step in creating the adder is to remove all gains and increase all losses. Staff therefore recommends removing the biased DA/RT price component altogether.

[25] PAC/100, Wilding 36.

ISSUE 3, STANDARD INPUTS AND ENERGY PRICE CHANGES

Q. Please summarize this issue.

A. Standard inputs refers 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. How did Staff investigate this issue?

A. Staff reviewed several DRs regarding the Company's planned maintenance scheduling, reasons for maintenance and related outages, and heat rates from 2018 to current year.[26] The Company's heat rate coefficients, as used to develop the 2023 transition adjustment mechanism (TAM), were derived from 48-months of historical information, where available.[27] In scheduling maintenance, the Company tries to avoid forecasted peak system needs while considering other factors such as the availability of contractors, weather conditions, system obligations during proposed schedule, and market power costs.[28] Staff does not have an adjustment for standard inputs.

Q. Has there been a change in energy prices since the last TAM?

[26] Staff/202, Cohen/1, PAC response to Staff DRs 1-5.
[27] Staff/202, Cohen/6, PAC response to Staff DR 5.
[28] Staff/202, Cohen/2, PAC response to Staff DR 2.

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 an uptick in historical energy prices.

FIGURE 14: ENERGY PURCHASE PRICES FROM OFPC DECEMBER 2021[29]

[redacted]

[redacted]

[redacted]

FIGURE 15: 2022 ICE MID-C PRICES

2022 ICE Prices	Ave High	Ave Low
Mid C Peak	40.95	37.77

[29] PAC Confidential Workpapers\ UE 400 TAM Confidential Version\Workpapers\OR UE-400 CONF 5-BD Work Papers\Generic\GNw_DA-RT Price Adder (2112) (CY2020-2023) CONF.xlsx

[redacted]

FIGURE 16: CONFIDENTIAL TABLE 1 ACTUAL NET POWER COSTS[30]

[redacted]

Q. Does this conclude your testimony?

A. Yes.

[30] PAC/100/Wilding, 5.

CASE: UE 400
WITNESS: HEATHER COHEN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 201

Witness Qualifications Statement

May 25, 2022

WITNESS QUALIFICATION STATEMENT

NAME: Heather Cohen

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Utility Analyst
Energy Rates, Finance and Audit Division

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

EDUCATION: Bachelor of Arts, Political Science
Fordham University, New York, NY

Master of Public Policy
American University, Washington, DC.

EXPERIENCE: I have been employed as a Senior Financial Analyst by the Oregon Public Utility Commission since January 2020 in the Energy, Rates and Finance 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. I have worked on the following general rate and power cost dockets: UG 388, UG 389, UG 390, UE 374, UE 390, UE 391, UE 394 and UW 184.

I have ten years of professional level budget and fiscal analysis experience. I was previously employed as a Budget Analyst with the Oregon Department of Education (ODE), where I was the lead analyst for the Early Learning Division (ELD) which includes the federal $97M Child Care Development Fund (CCDF) and $37M Preschool Promise program. Prior to ODE, I was a Senior Financial Analyst for the state of Texas's Department of Family and Protective Services and Health and Human Services. Before that, I was a Project Manager for the University of Southern California where I directed data collection and analysis, staffing and deliverables for a $1.2M federal grant related to the provision of mental health services in Los Angeles County. Prior to USC, I was a Senior Budget Analyst for the City of New York responsible for the $1B expense budget of the Administration for Children's Services (ACS).

CASE: UE 400
WITNESS: HEATHER COHEN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 202

Exhibits in Support
Of Opening Testimony

May 25, 2022

OPUC Data Request 1

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

Response to OPUC Data Request 1

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. Please refer to the Company's response to OPUC Data Request 2 for further considerations for scheduling maintenance.

OPUC Data Request 2

Standard Inputs - Please describe the factors considered, such as cost of replacement power, in adopting the timing of the 2023 maintenance for the resources.

Response to OPUC Data Request 2

When making decisions for the scheduling of planned maintenance for 2023, the Company considered 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. In addition, looking at 2023, there can be times of the year that planned outages can occur without the need for replacement power purchases as there can be excess system capacity based on system obligations. The Company tries to schedule planned 2023 outages to avoid forecasted peak system needs, i.e. peak summer obligations and peak winter obligations.

OPUC Data Request 3

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 2022.

(b) The dates, duration, and cause of scheduled outages occurring between 2018 and 2022.

(c) The dates, duration, and cause of scheduled outages forecasted for 2022. If the values used in this filing are expressed in a different manner than in the Company's responses to subparts (a) and (b), please provide both values.

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

Response to OPUC Data Request 3

The Company assumes that this request regarding "schedule outage rates for each unit" is intended to be asking for information about planned outages / scheduled maintenance of PacifiCorp's owned thermal resources (as also assumed in OPUC Data Request 1 and OPUC Data Request 2).

In addition, the Company interprets this request for "each test year from 2018 through 2022" 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).

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

(a) Please refer to Confidential Attachment OPUC 3-1 which provides the supporting confidential work papers for the forecast planned outages included in each of the TAM forecast calendar years 2018 through 2022. Please refer to the information provided above to cross-reference to the relevant TAM docket numbers.

(b) Please refer to Confidential Attachment OPUC 3-2 which provides actual scheduled / planned outage log / event information for calendar years 2018 through 2021. Note: actual data for calendar year 2022 is not yet available. The Company will supplement this response when additional information becomes available.

(c) Please refer to the Company's response to subparts (a) and (b) above.

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

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 4

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 2022.

(b) Actual heat rates for each unit, for each test year from 2018 through 2022.

Response to OPUC Data Request 4

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 2022" 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).

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

(a) Please refer to Confidential Attachment OPUC 4-1 which provides the supporting confidential work papers for the heat rates included in each of the TAM forecast calendar years 2018 through 2022. Please refer to the information provided above to cross-reference to the relevant TAM docket numbers.

(b) Please refer to Confidential Attachment OPUC 4-2 which provides actual heat rate data for calendar years 2018 through 2021. Note: actual heat data for calendar year 2022 is not yet available. The Company will supplement this response when additional information becomes available.

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 5

Standard Inputs - Please provide a narrative explanation of how PacifiCorp calculated its forecast of heat rates for the 2023 test year.

Response to OPUC Data Request 5

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. Based on the foregoing assumption, the Company responds as follows:

The Company’s heat rate coefficients, as used to develop the 2023 transition adjustment mechanism (TAM) were derived from 48-months of historical information, where available. Source coefficients are on a 100 percent plant basis and adjusted for the ownership level. Please refer to the confidential work papers provided with Company’s response to TAM Support Set 2 (5-business day work papers), specifically folder “Input Files”\”Thermal Data”, file “Aurora GN Heat Rate Definitions CONF”.

OPUC Data Request 8

Trapped Energy Revenue - If trapped energy was available, would AURORA then model a decrease generation at one of the Company's power plants or revise wholesale power sales? Would Nodal pricing also reduce generation at a plant as well in this case?

Response to OPUC Data Request 8

The trapped energy values seen in the 2023 transition adjustment mechanism (TAM) net power costs (NPC) report are the lowest possible values for the given set of system conditions. The AURORA model would not be able to decrease the generation any lower than any of the plants' minimum operational levels. In modeling the transmission topology of the Company's electrical system, the Company has captured all the congestion zones and transmission capabilities. This is true regardless of the granularity of the modeled transmission topology.

The Company assumes that the reference to "Nodal pricing" is intended to be a reference to the 2020 Multi-State Allocation Methodology (2020 Protocol) Nodal Pricing Model (NPM). Based on the foregoing assumption, the Company responds as follows:

The NPM consists of two components: (1) the day-ahead schedules received from the California Independent System Operator (CAISO), and (2) the allocation methodology. The day-ahead schedule from CAISO accounts for dispatchable generation at their minimum operation levels. If required, variable energy resources (VER) could be curtailed if needed, resulting in zero trapped energy. The allocation methodology is a method of allocating total NPC based on a state's load obligation (currently the 2020 Protocol).

CASE: UE 400
WITNESS: HEATHER COHEN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 203

IS CONFIDENTIAL AND SUBJECT TO

PROTECTIVE ORDER NO. 16-128

Exhibits in Support
Of Opening Testimony

May 25, 2022

CASE: UE 400
WITNESS: HEATHER COHEN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 204

IS CONFIDENTIAL AND SUBJECT TO

PROTECTIVE ORDER NO. 16-128

(Electronic format)

Exhibits in Support
Of Opening Testimony

May 25, 2022

CASE: UE 400
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 300
Market Caps, EIM Transfer Benefits

Opening Testimony

May 25, 2022

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 proposed change to its market cap methodology used to forecast off-system sales and its Energy Imbalance Market (EIM) transfer 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. For the 2023 TAM, I recommend rejecting the Company's use of the "average of averages" market cap method to forecast off-system sales and instead adopt the "third quartile of averages" method that was used in the 2022 TAM. This results in a reduction of $5.9 million to Oregon-allocated Net Power Costs (NPC). I make this recommendation in light of the misleading evidence presented by the Company and the mixed results I see from the Company's response to Staff DR 118.

Beyond the 2023 TAM, I recommend that the Company integrate a forward-looking forecast of off-system sales to replace the current ad hoc market cap methods that rely purely on past summary statistics. In my testimony, I discuss two suitable replacements in order to give the Company the flexibility to implement this modelling change without being overly prescriptive. These options are an update to AURORA to forecast off-system sales or a newly developed econometric forecasting model not unlike the model the Company uses to forecast EIM transfer benefits.

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

A. After receiving an update to the Company's response to Staff DR 37 that corrects the data used by the Company for its EIM transfer benefits forecast, I find that the Company's initial workpapers understate its initial EIM transfer benefits forecast by approximately $33 million system-wide and recommend that the Company update its total NPC to reflect the corrected data.

I also find that the model fit of two of the Company's four regressions used to forecast EIM transfer benefits have decreased after another year of data was added into the model. Of these two regressions, I recommend modifying one regression to both substantially improve model fit and to better adhere to econometric modeling best practices. This change is similar to the one I proposed in the 2022 TAM that was ultimately accepted by the Company in its reply testimony. The result of this change is a small offset to the large increase in forecasted EIM transfer benefits from using the correct data.

Using both the corrected data and implementing my econometric change results in a decrease in Oregon-allocated NPC by $8,718,899 for the 2023 TAM. Beyond the 2023 TAM, I recommend that the Company monitor the model fit and predictive power of its EIM transfer benefits forecast and discuss any changes to model fit or any changes to the regressions in future TAM proceedings.

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 claims in its opening testimony that its new software, AURORA, makes the same assumptions.[1]

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

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

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 in theory 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 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

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).
5 *In re PacifiCorp*, OPUC Docket No. UE 390, Order No. 21-379 at 26 (Nov. 1, 2021).

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 mimics market realities while mitigating some of the Company's perceived over-forecasting problem. The Commission adopted Staff's recommendation in Order No. 21-379.[7]

Q. What does PacifiCorp propose to do with its market caps in this proceeding now that it has implemented AURORA?

A. In its opening testimony, PacifiCorp proposes adopting the "average of averages" approach to forecast off-system sales in AURORA.[8] To support its position, PacifiCorp presents evidence showing that the AURORA model continues to over-forecast off-system sales even under the "third quartile of averages" method.[9] The Company further states that the use of its proposed "average of averages" method decreases thermal generation.[10]

---

6 *Id.*
7 *In re PacifiCorp*, OPUC Docket No. UE 390, Order No. 21-379 at 28 (Nov. 1, 2021).
8 PAC/100, Wilding/28.
9 PAC/100, Wilding/30.
10 PAC/100, Wilding/32.

The switch to the "average of averages" method would increase PacifiCorp's NPC forecast by $5.9 million.[11] The Company explains that this is driven largely by a decrease in sales revenue but is offset by a decrease in fuel and purchased power expenses.

Q. Do you agree with the Company's recommendation to use the "average of averages" approach even after its switch to AURORA?

A. No.

Q. Why not?

A. There are a few reasons that I think applying the "average of averages" method to AURORA is inappropriate.

1. The Company's evidence to support its switch to AURORA is incomplete and possibly misleading, and the Company has not been cooperative in providing the necessary evidence needed to justify the change in methodology. While I do not oppose the use of a more accurate forecasting method, the Company has not provided sufficient support to demonstrate that the "average of averages" method is superior in its testimony.
2. The Company's response to Staff DR 118 has shown that the "average of averages" method doesn't consistently provide a lower forecast of off-system sales than the "maximum of averages" method, running counter to the Company's narrative that the "average of averages" method is the root of the off-system sales forecasting problem.

[11] PAC/100, Wilding/33.

3. Much like Staff and intervenors in previous TAM proceedings, I do not believe that the correct way to mitigate the over-forecasting problem is to apply an ad hoc and backwards-looking method that brings the Company's model further away from reality, particularly in an era where the energy landscape is accelerating in a new direction.
4. The Company has stated that it is discussing changes to AURORA to allow AURORA to better handle off-system sales with Energy Exemplar – AURORA's creator. Given the possibility that the market cap adjustment may be eliminated or significantly changed and there is not enough evidence that the "average of averages" method constitutes an improvement in forecasting, a change from the market cap method used in the previous TAM is not warranted.

Q. In light of these objections, how do you recommend that the Company address its market caps in AURORA?

A. First, I recommend that the Company continue to use the "third quartile of averages" method for the 2023 TAM. Additionally, I recommend that the Company come back with a different, forward-looking way to forecast off-system sales in future TAM proceedings. This second piece could take the form of continued work with Energy Exemplar to better address off-system sales within the AURORA software or the creation of a new forward-looking forecast model that does not rely solely on past sales.

Reverting back to the "third quartile of averages" approach results in a reduction of $5.9 million on an Oregon-allocated basis.

Q. Regarding your first point, what evidence has the Company provided to support its claim that AURORA continues to over-forecast off-system sales and its method decreases thermal generation?

A. In its opening testimony, the Company provided a series of figures comparing the results of past TAM proceedings, Staff's adopted market cap methodology in UE 390, and the Company's proposed methodology in this docket. Figure 2 on PAC/100, Wilding/31 compares actual market sales from 2019 to 2021 with the 2022 forecasted sales under the "third quartile of averages" method and the 2023 forecasted sales under the proposed "average of averages" method. Figure 3 on PAC/100, Wilding/32 compares thermal generation between the 2022 TAM using the "third quartile of averages" method and the 2023 TAM using the "average of averages" method. Figure 4 on PAC/100, Wilding/32 compares the thermal generation in the 2023 TAM using the "average of averages" method and the "third quartile of averages" method.

Q. Why do you believe that these figures provide incomplete or misleading evidence?

A. There are a few ways in which PacifiCorp's evidence is lackluster or obfuscates a fair comparison:

- Figure 2 on PAC/100, Wilding/31 appears to be making the point that Staff's method in the 2022 TAM provides a less accurate forecast of off-system sales volumes than the Company's proposed method in the 2023 TAM by comparing them to the last three years of actual off-system sales. This figure makes no attempt to directly compare the two forecasting methods against each other and the Company was unresponsive to my data requests to provide a more direct comparison.[12]

- Figure 3 and Figure 4 on PAC/100, Wilding/32 contain data on forecasted thermal generation that could be easily combined into a single graph but are separated. In effect, this makes the difference between the Company's proposed method and the "third quartile of averages" method appear much larger than it actually is.
- The Company uses Figure 3 and Figure 4 to intimate that the thermal generation resulting from the "third quartile of averages" method runs counter to Oregon-mandated policies. In reality, the choice of market caps for the purpose of forecasting power costs has no effect on actual thermal generation.

Q. With regard to Wilding's Figure 2 in opening testimony, why is it important to have a direct comparison between the methods?

A. In empirical economic research, the Company's method to present data in Figure 2 can best be described as a crude "difference estimator", which is most appropriately used on time series data when only one thing changes, such as a change in policy or methodology. It is exceedingly rare to find a real-world situation where a difference estimator provides suitable enough evidence to

12 Staff/302, Dlouhy/2.

provide reliable results because there are often many other factors of significant magnitude that also feed into the data observed by the modeler.

In this case, Figure 2 on PAC/100, Wilding/32 compares the *actual* 2019-2021 results to *forecasted* 2022 results – which differ from the 2019-2021 actual results by being a forecast instead of actuals, having a market cap forecasting methodology change from the previous year, and being in a different energy market – and *forecasted* 2023 results – which contain *yet another* market cap forecast methodology change, another year with another different energy market, and a switch to AURORA from grid. In order to elicit a fair enough comparison to justify the Company's proposed change, some of these other confounding factors must be controlled for.

Q. How could the use of a difference estimator lead to incorrect conclusions?

A. As stated earlier, a difference estimator assumes everything else stayed the same, which is obviously not the case in Wilding's Figure 2, even if one were to assume that the underlying market fundamentals stayed relatively constant between years. While the figure seems to imply that the change brings the Company's market cap methodology closer to actual results by lowering the forecast, there's no way of knowing whether this was indeed the right adjustment, meaning that a change may not even be warranted.

Even if changing the forecast methodology is warranted, a lack of direct comparison does nothing to show us if the magnitude of the change is right. Put another way, without a comparison to past results and methodologies to

AURORA forecasts, making the changes suggested by the Company may *overcorrect* and provide an equally inaccurate forecast, just in a different direction. With today's rapidly evolving energy market, relying on indirect comparisons between future forecasts and past results is just not enough to justify large methodology changes.

Q. Have you tried to do something to control for these confounding factors?

A. Yes. I issued two data requests to provide a more direct comparison and eliminate some of these confounding factors. In this proceeding, I issued the Company data requests to match the 2019-2021 actual off-system sales using both past GRID-forecasted off-system sales – which used the "maximum of averages" method – and backcasts of off-system sales using AURORA and the "third-quartile of averages" method.[13,14] While this would still leave two items changing (i.e. different market cap methodologies and different software), this would provide a more direct comparison than the Company offered in its Figure 2.

Ideally, I would like to see backcasts using GRID and AURORA for 2019-2021 using both the "average of averages" method and the "third quartile of averages" method. However, I understand that is a large burden and did not request that the Company complete this analysis.

13 Staff/302, Dlouhy/1.
14 Staff/302, Dlouhy/2.

Q. Has the Company returned sufficient enough data to create this more direct comparison?

A. No. The Company returned only the forecasts for the 2019-2021 TAM proceedings using the "maximum of averages" results,[15] stating that performing backcasts using AURORA is overly burdensome.[16] Without this, a direct comparison still doesn't exist. Unless the Company can provide some sort of direct comparison between past actual off-system sales and AURORA-forecasted results, there will not be enough empirical evidence to justify a change to the market cap methodology in the 2023 TAM.

Q. Have you communicated with the Company about why it is necessary to elicit this comparison?

A. Yes. Staff met with the Company to discuss alternatives to Staff DR 16 that could generate some form of apples-to-apples comparison between methods in AURORA. After meeting with the Company, Staff issued DR 118 to provide a more direct comparison between AURORA and GRID by leveraging the Company's use of AURORA in the California and Washington equivalents of the 2022 TAM.[17] While this is less than an idea comparison due to different load forecasts being used in the other jurisdictions and a lack of any actual results to directly compare to, it can still provide some level of comparability between GRID, AURORA, the "average of averages" method, and the "third

15 Staff/302, Dlouhy/1.
16 Staff/302, Dlouhy/2.
17 Staff/302, Dlouhy/9.

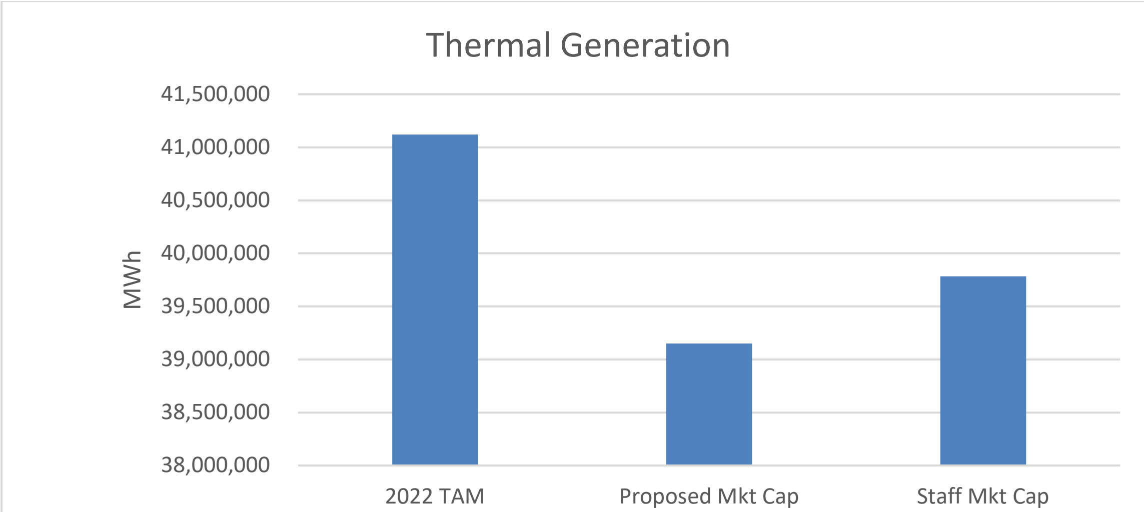
quartile of averages" method that was not originally provided. I will discuss the results of this comparison later on in testimony.

Q. With regard to Wilding's Figure 3 and Figure 4, why do you believe the Company's separation of the two figures is misleading?

A. Figure 3 and Figure 4 on PAC/100, Wilding/32 contain three distinct data points that are all directly comparable, namely the thermal generation in megawatt-hours in the 2022 TAM, the forecasted thermal generation in the 2023 TAM under the "average of averages" method, and the forecasted thermal generation in the 2023 TAM under the "third quartile of averages" method. When separated out and scaled in the way the Company chose to do, it appears that the "average of averages" method greatly reduces thermal generation relative to the 2022 TAM and the "third quartile of averages" method totally reverses this.

When all three data points are put together, a different story is told, as can be seen in Figure 1 below. Indeed, it is still true that the "average of averages" method produces lower thermal generation than the "third quartile of averages" method, but both reduce thermal generation by over a million megawatt-hours. While it is only a visual representation, Figure 1 underscores my previous point about the importance of direct comparison, as PacifiCorp's proposed market cap may have appeared to be the only driving factor in the reduction of thermal generation if it were not compared directly to the "third quartile of averages" method.

Figure 1: Forecasted Thermal Generation Under Market Cap Proposals



Q. What does the Company mean when it says that Staff's market cap methodology runs counter to Oregon-mandated policies?[18]

A. Although the Company does not state which policies the "third quartile of averages" approach mismatches, I assume that the Company means that anything that increases thermal generation contradicts Oregon's long-term decarbonization goals as captured in the governor's Executive Order 20-04. If the market caps do indeed cause the Company to increase its actual thermal generation, then there could be a valid reason to accept the Company's change. However, this is not the case.

Q. How do you know that the choice of market cap methodology does not affect actual emissions?

A. In response to Staff DR No.17, the Company states "Net power costs (NPC) forecasts do not directly lead to a reduction of actual emissions."[19] Therefore,

[18] PAC/100, Wilding/32.
[19] Staff/302, Dlouhy/3.

although the market cap methodology may lead to a different NPC and thermal generation forecast, it has no bearing on the Company's actual choice of whether to run a thermal plant when power needs to actually be generated.

Q. Regarding your second point, please describe what led you to issue Staff DR 118.

A. The Company has stated that the "average of averages" method is superior to the "third quartile of averages" method in that it mitigates the over-forecasting problem. As stated earlier, I had hoped to compare methods to past TAM results, but the Company viewed the request overly burdensome.

As a compromise, I requested that the Company provide the results of the 2022 Washington Power Cost Only Rate Case (PCORC) and the California Energy Cost Adjustment Clause (ECAC), which were calculated using the "average of averages" method in AURORA. These are the California and Washington equivalents of the TAM. I also asked that the Company do AURORA runs of these power cost cases using the "third quartile of averages" approach. The hope here was to compare the off-system sales under AURORA using two different market caps methods to the off-system sales forecasted in Oregon using GRID.

However, comparing just the Washington results to the California results provides ample evidence that the choice of market cap methods is not the source of the off-system sales problem.

Q. Why does the Company's response to DR 118 seem to imply that the market cap methodology is not the source of the off-system sales problem?

A. In the Company's response to Staff DR 118, it appears that the "third quartile of averages" method would forecast higher off-system sales in dollar terms in the California ECAC than the "average of averages" method, but *lower* off-system sales in the Washington PCORC in dollar terms. This can be seen in Figure 2 where I compare the total system balancing sales in dollar terms between the two states' filed methods and using the "third quartile of averages" method. Further, it's clear that the results for each of these proceedings is being substantially affected by something other than the market cap method choice, as the difference in the filed results for Washington and California varies by much more than the choice of market caps.

Figure 2: California ECAC and Washington PCORC[20]

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. What else could be driving this disparity between the two power cost filings that took place in the same year?

A. In discussions with the Company over alternatives to my request in Staff DR 16, the Company noted that comparing across jurisdictions is imperfect, as different load forecasts are used in forming the NPC forecast. The Company stated in its response to Staff DR 118 that other things vary from the 2023 TAM, such as the forward price curve, coal price, and market depth. Figure 2 above clearly suggests that these other factors not only dominate the effect of market caps, but also reverse their effects when it comes to sales dollars instead of sales volumes.

[20] Data from this figure compiled from Confidential Attachments 1 to 4 to PacifiCorp's response to Staff DR 118, filed electronically.

Therefore, the Company's suggested change to its market caps methodology appears to be unwarranted. Further, the disparity between jurisdictions points to a need for a different solution to forecast off-system sales than the existing market cap methodologies used.

Q. Regarding your third point, what is wrong with the current market cap methods?

A. All three market cap methods that have been either used or proposed since UE 245 have relied entirely on summary statistics based on the last four years of operation. Doing this necessarily ignores any known, explanatory changes to the market or the Company's system that have occurred in the last four years or anticipated changes in the future. CUB brought up this concern during UE 390 and recommended that a forward-looking forecast of off-system sales be used in place of the current market cap methodology.[21]

As I've touched on while discussing PacifiCorp's scant evidence, the electricity market is changing quickly, making many prevailing market conditions, generation options, and ways to transact from four years ago obsolete today. As such, any method that is fundamentally built on past data without integrating known or expected changes will be hindered when forecasting future operations, no matter how it is modified.

[21] *In re PacifiCorp*, OPUC Docket No. UE 390, Order No. 21-379 at 26 (Nov. 1, 2021).

Q. Given this objection, what do you recommend the Company do for the 2023 TAM and any future TAM proceedings?

A. Any large revamps to the market cap methodology for the 2023 TAM would be unduly burdensome and half-baked in such a short time frame, so I recommend using one of the previously adopted methods. For all the reasons previously discussed, I believe that the most appropriate method is the "third quartile of averages" method adopted by the Commission for the 2022 TAM.

Beyond the 2023 TAM proceeding though, I recommend that the Company produce a different method to forecast its off-system sales for all future proceedings. When I make this recommendation, I recognize that this is a non-trivial request. As such, I recommend that the Company be given the freedom to pursue two distinct paths to accommodate this request. I will discuss these distinct paths later in my testimony.

Q. Regarding your fourth point, how does the Company's correspondence with Energy Exemplar inform your recommendation?

A. In response to Staff DR No. 67, the Company states that it is engaged in ongoing discussions to incorporate off-system sales into its AURORA software.[22] Therefore, the entire conversation of the choice of a market cap method to forecast off-system sales may be a moot point in the near future. While that doesn't solve the off-system sales problem in the 2023 TAM, it means that any precedential change to the Company's off-system sales is inappropriate at this time. As such, I continue to recommend that the Company

---

[22] Staff/302, Dlouhy/8.

retain the "third quartile of averages" method while Company engages in conversations with Energy Exemplar.

Q. Please further discuss the two distinct paths you envision for the market cap methodology in future TAM proceedings you previously alluded to.

A. As I previously brought up in testimony, I recommend that the Company find a forward-looking method to forecast off-system sales in future TAM proceedings and as I note above, I think it is appropriate to allow the Company to pursue two distinct paths to develop a forward-looking off-system sales forecast.

The first path would be to continue discussions with Energy Exemplar to incorporate off-system sales into its AURORA software. Doing so would make obsolete the "maximum of averages", "average of averages", and "third quartile of averages" methods and presumably address my concern, and concern voiced in previous TAM proceedings, that the market cap methodology is not forward looking. However, I recognize that even if the Company is engaged in conversations with Energy Exemplar, there is no guarantee that these conversations will be fruitful. I believe that the Company should be given the option of an alternative path to pursue a forward-looking forecasting solution should Energy Exemplar be unable to incorporate off-system sales into AURORA by the 2024 TAM, or ever.

As an alternative path, I recommend that the Company create an econometric model to forecast future off-system sales. In principle, this would be similar to the Company's method that has been used to forecast its EIM transfer benefits in the previous two TAM proceedings.

Q. Please describe what you would expect to see in an econometric model.

A. This econometric model should take in past data on actual off-system sales at various hubs, market dynamics, weather, and company resources as inputs, and produce an estimate of off-system sales at the hub-month-on/off peak level as a function of these inputs. Up-to-date econometric, time series, and panel data techniques should be incorporated where appropriate. Once the relationship is established between the inputs and the off-system sales, expected future values of the inputs can be used to produce a forward-looking estimate of off-system sales at each of the Company's hubs.

While I recommend some form of econometric model and loosely suggest a set of inputs that would presumably explain off-system sales, my intent is not to be overly prescriptive. It would be irresponsible to fully specify an econometric model without proper planning, hypothesis testing, robustness checks, and bias correction. Should the Company choose to create an econometric model to forecast off-system sales, I expect that the Company would undergo these steps and provide the Commission with the proper justification for its modelling choices.

Q. It sounds like you're recommending that the Company create a model based on past inputs. How does this differ in principle from the current methodologies proposed in this TAM?

A. Although an econometric model utilizes past data, the past data is only used to estimate a best-fit model rather than to provide the totality of results. The estimated best-fit model then maps a relationship between a set of inputs and an output. This model can then take in *new forward-looking* inputs to estimate something outside of the data used to create the model. In this way, the Company can incorporate new information to inform its off-system sales in a way that the current market cap methodologies could not.

As a simple example, suppose that it is estimated that high temperatures in California cause large sales volumes at one of the market hubs and a certain mix of resources is correlated with a change in trading patterns in past years. PacifiCorp can then input data on expected weather patterns and resources expected to come online for the upcoming year to produce an estimate of off-system sales that captures the nuances of an evolving energy market in a way that the current method cannot.

Q. Please summarize your recommendation regarding the Company's proposed changes to market caps.

A. I recommend that the Company maintain its "third quartile of averages" method for the purpose of calculation power costs for the 2023 TAM in place of the "average of averages" method proposed by the Company. This results in a reduction of $5.9 million in Net Power Costs relative to the Company's filing.

I further recommend that the Company cease using backwards-looking summary statistic methods to forecast off-system sales in its future TAM proceedings. Instead, I recommend that the Company do one of two things:

- Continue talks with Energy Exemplar to incorporate off-system sales into its AURORA software and implement the updated AURORA when available.
- Create an econometric model to forecast off-system sales to be used in the 2024 TAM and beyond or until AURORA can adequately forecast off-system sales.

ISSUE 2. EIM TRANSFER BENEFITS

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

A. PacifiCorp tracks three types of EIM benefits: Energy transfer benefits, GHG benefits, and flex reserve benefits. My testimony addresses the regression model used to forecast energy transfer benefits.

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 two TAM proceedings. In the 2022 TAM, Staff recommended changes to part of the Company's forecasting model that were ultimately adopted by the Company.[23]

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

[23] Staff/302, Dlouhy/4.

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 2021, with the exception of the PACE Import model whose data begin in December 2015.

Q. Have the regressions changed at all since the 2022 TAM?

A. No. In the 2022 TAM, I testified that both the PACW and PACE Export regressions contained some variable transformations that were outside econometric norms. In particular, both of these models relied on taking the square root of the price data in lieu of the natural log, which was used for the other two models and is much more accepted in econometric modelling. I recommended changes to the PACE 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. Why didn't you recommend an equivalent change to the PACW Export model?

A. Although the same econometric oddity was present in the PACW Export model, I recommended no changes to that model because my investigation showed that replacing square root transformations with natural log transformations in the regression reduced model fit enough that it was no longer a useful forecasting tool.

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

A. Yes. The Company accepted that change for the 2022 TAM and continues to use it in the 2023 TAM.[24] As it stands, the Company estimates the following set of regressions to forecast its EIM transfer benefits in its initial filing:

[BEGIN CONFIDENTIAL]

[redacted]

[24] Staff/302, Dlouhy/4.

[redacted]

[END CONFIDENTIAL]

Q. What is the Company's total EIM transfer benefit for the 2023 TAM?

A. According to workpapers and the code provided by the Company in its initial response to Staff DR 37, the total EIM transfer benefit is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** system wide, or **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** on an Oregon-allocated basis.

Q. Do you have any reason to doubt the validity of the Company's total EIM transfer benefit as reported in its workpaper?

A. Yes. According to the Company's revised response to Staff DR 37 provided May 17, 2022, the data the Company provided in its initial response to support the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** total EIM transfer benefit contained in its filed workpapers is incorrect.[25] The Company states that its initial narrative is still correct, but that the files containing the model inputs and model outputs in its initial response were incorrect. The Company provided the correct files in its supplemental response.

[25] Staff/302, Dlouhy/6.

Q. What is the effect on the 2023 EIM transfer benefits forecast of using the correct model inputs?

A. Leaving the Company's code unchanged, using the correct model inputs raises the total EIM transfer benefits system wide to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, an increase of over $33 million.

Purely on the basis of using the correct model inputs, I recommend adjusting the Company's total NPC in the 2023 TAM downward. I also suggest modifying one of the Company's regressions used to generate this estimate to improve model fit. This recommended change has a much more modest effect on the Company's total EIM transfer benefits that I will summarize later.

Q. Why do you recommend changes to the regression models the Company uses to forecast EIM transfer benefits for the 2023 TAM?

A. With another year's worth of data, it appears that the model fit for two of the four regressions decreased, one of which decreased substantially. The only model fit to improve dramatically over this time was the PACE Exports model – the regression that I recommended be changed in the 2022 TAM. Notably, the model fit of the Company's PACW Export model – the only remaining model to rely on unconventional square root and square transformations – has decreased significantly. Table 1 shows how the Adjusted R-Squared – a widely-used metric for model fit – for each of the four regressions has changed since the added 11 data points were introduced.[26] Again, it is worth pointing

[26] I include a larger discussion on the Adjusted R-Squared and other methods of model fit later in this testimony.

out that the only factor driving the change in model fit is the addition of more data points.

Table 1: Changes in EIM Transfer Benefits Adjusted R-Squared

[BEGIN CONFIDENTIAL]

[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

[END CONFIDENTIAL]

Q. Why would the model fits change so dramatically over this time?

A. Each model relies only on at most 84 observations in the 2023 TAM, which is significantly more than the 73 used in the 2022 TAM. While adding so many observations relative to the previous pool is incredibly worthwhile, it can reveal data patterns that could not be previously observed. As these patterns become apparent, models that appeared to be matching the data correctly may now appear outdated or inaccurate.

Q. Do you have any changes to the Company's regression models as these changes become known?

A. Yes. Although the model fit did decrease in two of the four models, I only recommend changing the PACW Export model to incorporate natural logs in place of square roots for the 2023 TAM. After this change is implemented, the estimating equation becomes:

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. If the model fit has decreased for two of the four regressions, why do you only recommend changes for the PACW Exports model?

A. First, as can be seen in Table 1, the PACW Exports model experienced a substantially larger decrease in model fit than the other problematic model. However, there are also principled reasons to suggest these changes as well.

As I've discussed earlier, the PACW Exports regression contains an added problem that is not present in the other regression whose Adjusted R-Squared decreased, namely that the econometric underpinnings of the model are questionable because of the choice to use square roots and squared terms in lieu of the more common method of taking natural logs when building models around price data. Combined with its sharp drop in model fit, its status as an outlying model makes it difficult to justify its continued use.

Although the small decline in model fit for the PACE Imports troubling, the natural log-based model specifications are a more generally-accepted econometric practice. Further, changes in model fit are to be expected when a relatively large number of observations are added to a sparse data set. I recommend that monitoring the performance of all these regressions be a point of emphasis in ensuing TAM proceedings, but I advise against changes to all but the PACE Exports regression at this time.

Q. Why do you focus only on the Adjusted R-Squared to measure model fit?

A. There are a variety of tools that a modeler can use to determine which model is best for forecasting, including evaluating the Mean Squared Error, backcasting data, or evaluating model fit using R-Squared or Adjusted R-Squared. In my experience, I've found that these methods will often pick the same model as the best model. For the purposes of this testimony, I've chosen to focus on the Adjusted R-Squared for a few reasons:

- Backcasting with regressions requires the modeler to omit past values to see how the model performs in predicting past values. For example, the model could fit the regression on 2015-2021 data, and then use inputs from 2014 to see how the backcasted results for 2014 compare to the actual results. As I've previously stated, each of these models only has at most 84 monthly data points and I have discussed how the model fit has changed drastically when observations are omitted.
- R-Squared measures how well a model fits and will necessarily rise as the number of inputs rises. By design, it varies between 0 and 1, with higher numbers representing better model fit. For most people who have worked with regressions, R-Squared is the most intuitive measure to compare a model's power. This makes R-Squared useful when comparing models with the same number of inputs but can fail when comparing models with vastly different numbers of inputs. While the scales are different, the R-Squared can be used for the same purpose as the Mean Squared Error.

- Adjusted R-Squared is similar to R-Squared in that it measures model fit on a 0 to 1 scale with the same interpretation, but it penalizes a model that has a lot of useless parameters. Including too many parameters in a model is known as "overfitting," and can lead to weak predictive power and unclear interpretation of the relationship between variables of interest. This makes it easier to compare models with different number of parameters while still being intuitive like R-squared. There are other methods that also penalize overfitting, such as the Akaike Information Criterion, but I choose to focus on Adjusted R-Squared in this testimony for accessibility of interpretation.

Q. How has does using your alternate specification for the PACW Exports model change the Adjusted R-Squared?

A. As shown above, the Adjusted R-Squared for the PACW Export model the Company used in its filing was **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Using my recommended alternate model, the Adjusted R-Squared rises to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. While any measure of model fit is relative, this is a substantial increase, particularly given that the same number of parameters were used in both the Company's proposed model and my alternate recommendation.

Q. How does this change the Company's EIM transfer benefit forecast?

A. After estimating my model using the Company's corrected data provided in its revised response to DR 37, I also made the necessary changes to the Company's code to ensure that my code is properly integrated into the Company's forecast. All told, this modelling change results in an EIM transfer benefit forecast of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** system wide. This equates to a small decrease in benefits relative to the benefits using the Company's corrected data, measured at $314,963 system wide or $81,922 on an Oregon-allocated basis.

Q. What is your total recommended adjustment to the Company's EIM transfer benefits?

A. After using the correct data and implementing my modeling change previously discussed, I recommend that the Company decrease its NPC forecast by $8,718,899 to correspond with an increase to forecasted Oregon-allocated EIM transfer benefits of this amount.

This recommendation is driven almost entirely by using the corrected data provided by the Company in its May 17 supplement to Staff DR No. 37 but is minimally offset by my suggested model change.

Q. Do you have any other recommendation on this topic?

A. Yes. I recommend that the Company include a discussion of how its EIM transfer benefits models perform in its next TAM filing. In this discussion, I expect that the Company clearly outline changes in model fit using the Adjusted R-Squared or another suitable measure with the addition of data.

Should the Company choose to modify the econometric specification of any of its models, I would expect a discussion that addresses the effect that the new specification has on model performance as well.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 400
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 301

Witness Qualification

May 25, 2022

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 Energy 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, and UE 400 (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 400
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 302

Non-Confidential Responses to Staff Data Requests.

May 25, 2022

OPUC Data Request 15

Market Cap Methodology - Refer to Confidential Figure 2 on PAC/100, Wilding/31. Please reproduce this figure to also include the forecasted market sales for 2019-2021 from the associated TAM and provide any underlying data used to generate these figures.

Response to OPUC Data Request 15

PacifiCorp objects to this request as requiring the Company to develop information or prepare a study, and not reasonably calculated to lead to the discovery of admissible information. Without waiving the foregoing information, the Company responds as follows:

Please refer to the Company's response to OPUC Data Request 14, specifically Confidential Attachment OPUC 14-1, file "Attach OPUC 14-15-19 CONF.xlsx", tab "OPUC 15 CONF".

For underlying data, please refer to the Company's response to OPUC Data Request 14, specifically Confidential Attachment OPUC 14-2, and the files from previous transition adjustment mechanism (TAM) files as list below:

2021 TAM (Docket UE-375) - sales volume - please refer to confidential file "_Final ORTAM21 Fin Nov NPC CONF -TB and Pryor Increase.xlsm", tab "NPC", cell E366.

2020 TAM (Docket UE-356) - sales volume - please refer to confidential file "NovFin ORTAM20 NPC CONF_2019 11 15 Final.xlsm", tab "NPC", cell E362.

2019 TAM (Docket UE-339) – sales volume – please refer to confidential file "NovFin ORTAM19 NPC Final CONF", tab "NPC", cell E352.

OPUC Data Request 16

Market Cap Methodology - Refer to Confidential Figure 2 on PAC/100, Wilding/31. Please reproduce this figure to also include the forecasted market sales for 2019-2021 using equivalent inputs in AURORA from those years and the "third quartile averages" approach and provide any underlying data used to generate these figures.

Response to OPUC Data Request 16

The Company objects to this request as overly broad, unduly burdensome, requiring the Company to develop information or prepare a study, lacking a high degree of relevance to the proceeding, and not reasonably calculated to lead to the discovery of admissible information. Without waiving the foregoing objection, PacifiCorp responds as follows:

Reformatting and converting the requested input data that has been used for past transition adjustment mechanism (TAM) forecasts using the Generation and Regulation Initiative Decision Tool (GRID) to create equivalent input data that could be imported in the AURORA model is extremely burdensome and PacifiCorp is unable to conduct this requested analysis.

OPUC Data Request 17

Market Cap Methodology - On, PAC/100, Wilding/32, the Company states, "As seen in Figure 4 below, PacifiCorp's proposed market cap limits reduce thermal generation, thereby leading to reduced emissions." Please discuss how a forecast made more than a year in advance of generation reduces actual emissions in 2023.

Response to OPUC Data Request 17

Net power costs (NPC) forecasts do not directly lead to a reduction of actual emissions. PacifiCorp's proposed market cap methodology leads to reduction in forecasted wholesale sales volumes and thereby reduces forecasted thermal generation. This leads to a transition adjustment mechanism (TAM) forecast that reflects reduced emissions.

Additionally, please refer to the direct testimony of Company witness, Michael G. Wilding, specifically Exhibit PAC/100, Wilding/27-33, which describes how PacifiCorp's approach to market cap methodology is more reflective of the Company's operational reality.

OPUC Data Request 37

EIM participation - Regarding the Company's EIM benefit forecast model(s):

(a) Please provide a copy of each of the Company's EIM benefit model(s) in electronic workbook format, with all cells and formulas intact.

(b) For each model provided, please provide a narrative explanation of how the model works.

(c) Please indicate where the EIM benefit amount can be seen in each model, providing a specific reference to the cell and tab in which it appears in each workbook.

(d) Please indicate where the EIM benefit amount shown in response to subpart (c) appears in the Company's filing, providing a specific reference to the cell and tab in which it appears in each workbook.

Response to OPUC Data Request 37

For the Company's 2023 transition adjustment mechanism (TAM) for calendar year 2023:

(a) Please refer to Confidential Attachment OPUC 37.

(b) Each model follows the descriptions laid out in Public Utility Commission of Oregon (OPUC) staff's Opening Testimony in the Company's 2022 TAM, Docket UE-390, specifically the Opening Testimony of OPUC staff witness, Dr. Curtis Dlouhy, Exhibit Staff\ 800 and incorporates all proposed recommendations. Here is a summary of the four models:

  i. The "PACE Export Model" uses a double log econometric model using a log transformation of power price, a log transformation of gas price, and two dummy variables ("Enbridge" and "CAISO-PAC" bilateral) to predict a log transformation of margins.

  ii. The "PACW Export Model" uses the independent variables gas price, power price and the "Enbridge" dummy variable to predict margins. Gas price and power prices are modified using a quadratic transformation. Margins are modified using a square root function. The Company continues to use this model specification because the goodness of fit as it is still an improvement over the log-log formulation.

iii. The “PACE Import Model” uses a double log econometric model using a log transformation of power price, the total transmission capacity, and the total capacity from operating and planned solar resources in the California Independent System Operator (CAISO) to predict a log transformation of margins.

iv. The “PACW Import Model” uses a double log econometric model using a log transformation of power price, the total transmission capacity, and the total capacity from operating and planned solar resources in CAISO to predict a log transformation of margins.

(c) Please refer to Confidential Attachment OPUC 37. The energy imbalance market (EIM) benefit forecast amount for 2023 is provided in file “EIMForecast.csv”, tab “EIMForecast”, cellsT50 through T61.

(d) Please refer to the Company’s response to TAM Support Set 1 (concurrent work papers), specifically confidential work paper “ORTAM23 NPC CONF.xlsx”, tab “EIM”, cells D2 through O2.

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 37

EIM participation - Regarding the Company's EIM benefit forecast model(s):

(a) Please provide a copy of each of the Company's EIM benefit model(s) in electronic workbook format, with all cells and formulas intact.

(b) For each model provided, please provide a narrative explanation of how the model works.

(c) Please indicate where the EIM benefit amount can be seen in each model, providing a specific reference to the cell and tab in which it appears in each workbook.

(d) Please indicate where the EIM benefit amount shown in response to subpart (c) appears in the Company's filing, providing a specific reference to the cell and tab in which it appears in each workbook.

1st Revised / 1st Supplemental Response to OPUC Data Request 37

Further to the Company's response to OPUC Data Request 37 dated April 20, 2022, the Company provides the following (1) revised, and (2) supplemental information:

(1) Upon further review, the Company became aware that the energy imbalance market (EIM) benefits model inputs and outputs provided with the Company's original response to OPUC Data Request 37, specifically Confidential Attachment OPUC 37, provided incorrect versions of the model inputs and outputs. Please refer to Confidential Attachment OPUC 37 1st Revised which replaces, in its entirety, the contents of Confidential Attachment OPUC 37. Note: the Company's original narrative response to OPUC Data Request 37 remains unchanged and valid. However, the correct supporting model inputs and outputs are provided in Confidential Attachment OPUC 37 1st Revised.

(2) In addition, on May 10, 2022, Public Utility Commission of Oregon (OPUC) staff advised that as well as requesting information on EIM benefits, OPUC staff intended OPUC Data Request 37 to also request information on greenhouse gas (GHG) benefits. Based on this additional request, the Company provides the following supplemental information related to GHG benefits:

    (a) Please refer to Confidential Attachment OPUC 37-1 1st Supplemental which provides the GHG Benefit Forecast. One change was made between the GHG Benefit Forecast provided in Confidential Attachment OPUC 37-

1 1st Supplemental and the GHG Benefit Forecast that was provided in the 2022 transition adjustment mechanism (TAM), Docket UE-390. Between the months of April 1, 2021 and December 31, 2021, GHG benefit actuals were formed from the emissions factors that expired on April 1, 2020. Note: emission factors are used to construct the GHG Bid Price. Please refer to Confidential Attachment OPUC 37-2 1st Supplemental which provides a comparison of before and after the above referenced change / update, specifically tab “GHG Benefits Compare”. The GHG Bid Prices used to generate the GHG benefits are included in tab “GHG Bid Prices”.

(b) The GHG Benefit Forecast is constructed by averaging GHG benefits recorded over the past three years. The methodology then applies seasonal weights to shape the forecast. Future benefits are marked up relative to the Company’s forecasted inflation rate. GHG benefits attributed to hydro exports received an additional 5 percent growth rate for forecasting future years.

(c) The total GHG Benefit Forecast is provided in cell F98 on tab “GHG Benefits” of Confidential Attachment OPUC 37-1 1st Supplemental.

(d) Please refer to the Company’s response to TAM Support Set 1 (concurrent work papers), specifically confidential work paper “ORTAM23 NPC CONF.xlsx”, tab “EIM”, cells D3 through O3 for GHG Benefit Forecast values

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 67

Market Cap Methodology - Refer to the Company's response to OPUC Data Request 12 where it states, "Models such as AURORA do not possess the capability to model dynamic assumptions." Please discuss any efforts the Company has made to modify AURORA to integrate dynamic assumptions or to contact Energy Exemplar to explore alternative methods to forecast off-system sales.

Response to OPUC Data Request 67

PacifiCorp has had discussions with Energy Exemplar LLC (the developer of the AURORA software) to explore the possibility of incorporating off-system sales within the AURORA model. Discussions are ongoing at this time.

OPUC Data Request 118

Market Cap Methodology - Following the discussion with Staff on May 13, 2022 regarding Staff DR 16, please provide the following data:

(a) The final update of the 2022 Washington Power Cost Only Rate Case (PCORC) as filed. Please also confirm that this was calculated using the "average of averages" market caps method in AURORA and identify the forecasted off-system sales.

(b) The final update of the 2022 PCORC with the Company instead using the "third quartile of averages" market caps method. Please also identify the forecasted off-system sales.

(c) The 2022 California Energy Cost Adjustment Clause (ECAC) as filed. Please also confirm that this was calculated using the "average of averages" market caps method in AURORA and identify the forecasted off-system sales.

(d) The 2022 California ECAC with the Company instead using the "third quartile of averages" market caps method. Please also identify the forecasted off-system sales.

Response to OPUC Data Request 118

The Company clarifies that the 2022 Washington Power Cost Only Rate Case (PCORC) is filed with the Washington Utilities and Transportation Commission (WUTC) under Docket UE-210402. The Company further clarifies that the 2022 California Energy Cost Adjustment (ECAC) is filed with the California Public Utilities Commission (CPUC) under Application (A) 21-08-004. Based on the foregoing clarification / understanding, the Company responds as follows:

As agreed with Public Utility Commission of Oregon (OPUC) staff during discussions held on May 13, 2022, the Company is providing responses to subparts (a) and (c) in this response. The Company's responses to subparts (b) and (d) will follow shortly in a supplemental response.

(a) Please refer to Confidential Attachment OPUC 118-1. PacifiCorp confirms that this net power costs (NPC) report, which was filed with the WUTC in Docket UE-210402 (PCORC), uses the "average of averages" market caps methodology in the AURORA model.

Please refer to tab "NPC", rows 34-41 for wholesale sales amount, and rows 344-352 for the wholesale sales volume.

Additionally, the Company would like to note that this forecast has different input assumptions and modeling conventions such as forward price curve (FPC), coal prices, market depth, and unit cycling when compared to the 2023 Transition Adjustment Mechanism (TAM).

(b) As agreed with OPUC staff, the Company will respond to this subpart in a supplemental response shortly.

(c) Please refer to Confidential Attachment OPUC 118-2. PacifiCorp confirms that this NPC report, filed with CPUC in A.21-08-004, uses the "average of averages" market caps methodology in the AURORA model.

Please refer to tab "NPC", rows 34-41 for wholesale sales amount, and rows 348-355 for the wholesale sales volume.

Additionally, the Company would like to note that this forecast has different input assumptions and modeling conventions such as FPC, coal prices, market depth, and unit cycling when compared to the 2023 TAM.

(d) As agreed with OPUC staff, the Company will respond to this subpart in a supplemental response shortly.

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 118

Market Cap Methodology - Following the discussion with Staff on May 13, 2022 regarding Staff DR 16, please provide the following data:

(a) The final update of the 2022 Washington Power Cost Only Rate Case (PCORC) as filed. Please also confirm that this was calculated using the "average of averages" market caps method in AURORA and identify the forecasted off-system sales.

(b) The final update of the 2022 PCORC with the Company instead using the "third quartile of averages" market caps method. Please also identify the forecasted off-system sales.

(c) The 2022 California Energy Cost Adjustment Clause (ECAC) as filed. Please also confirm that this was calculated using the "average of averages" market caps method in AURORA and identify the forecasted off-system sales.

(d) The 2022 California ECAC with the Company instead using the "third quartile of averages" market caps method. Please also identify the forecasted off-system sales.

1st Supplemental Confidential Response to OPUC Data Request 118

Further to the Company's response to OPUC Data Request 118 dated May 18, 2022 which provided the Company's responses to subparts (a) and (c), the Company now provides the following 1st Supplemental response addressing subparts (b) and (d):

The Company clarifies that the 2022 Washington Power Cost Only Rate Case (PCORC) is files with the Washington Utilities and Transportation Commission (WUTC) under Docket UE-210402. The Company further clarifies that the 2022 California Energy Cost Adjustment (ECAC) is filed with the California Public Utilities Commission (CPUC) under Application (A) 21-08-004. Based on the foregoing clarification / understanding, the Company responds as follows:

(b) Please refer to Confidential Attachment OPUC 118-3.

(d) Please refer to Confidential Attachment OPUC 118-4.

Additionally, the Company would like to note that the Washington PCORC filing was performed using the March 2022 official forward price curve (OFPC), and the California ECAC filing was performed using the March 2021 OFPC, while this 2023 transition adjustment mechanism (TAM) was performed using the December 2021 OFPC.

Please refer to Confidential Attachment OPUC 118-5 which provides the forecasted off-system sales from the 2022 California ECAC and the 2022 Washington PCORC. This attachment replicates Confidential Figure 2 from the direct testimony of Company's witness, Michael G. Wilding with additional data points.

Please refer to the confidential figure provided below which shows a market sales volumes comparison between actual sales volumes for 2018 through 2021 and various hypothetical net power costs (NPC) runs performed by the Company with the adjustment of using the "Staff's Market Cap" methodology:

[redacted]

[redacted]

[redacted]

Additionally, please refer to the confidential figure provided below which shows a market sales volumes comparison between actual sales volumes for 2018 through 2021 and various NPC runs performed by the Company with the adjustment of using the "Averages of Average Market Cap" methodology:

[redacted]

[redacted]

[redacted]

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 400
WITNESS: MADISON BOLTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 400

Opening Testimony

May 25, 2022

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

A. My name is Madison Bolton. I am a Utility 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 qualification statement is found in Exhibit Staff/401.

Q. What is the purpose of your testimony?

A. I analyze treatment of Production Tax Credits (PTCs), Consumer Opt-out Charges for Direct Access, and expense for qualifying facilities in PacifiCorp's 2023 Transition Adjustment Mechanism (TAM) filing, Docket No. UE 400.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Exhibit Staff/402, consisting of two pages.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. PRODUCTION TAX CREDITS & WIND NPC BENEFITS

Q. How does PAC's wind generation benefit customers?

A. As discussed in the testimony of witness Michael G. Wilding, the Company's wind generation included in this TAM is a zero-fuel cost resource that replaces higher cost market purchases and coal generation.[1] This lower cost wind generation reduces total company NPC by $221.6 million. PacifiCorp's wind projects also earn Production Tax Credits (PTCs) for every kilowatt-hour (kWh) of electricity generated, which are applied as a reduction to NPC. The Company has forecasted an Oregon-allocated $70.2 million in PTCs for the 2023 TAM resulting in a decrease of $1.8 million to NPC compared to the 2022 TAM.

Q. What is the current Production Tax Credit (PTC) rate?

A. At the time of the Company's initial filing, the US Internal Revenue Service (IRS) had published a current PTC rate of 2.7 cents per kWh for 2022. PacifiCorp assumes a rate of 2.7 cents in the Company's calculation for PTC revenue for the 2023 TAM.

Q. How is the total PTC benefit calculated?

A. The Company multiplies the forecasted PTC rate (2.7 cents per kWh) by the Oregon-allocated forecasted wind generation for the 2023 TAM, then grosses up for the tax rate.

Q. Why is the PTC rate adjusted annually?

[1] PAC/100, Wilding/56 at line 6.

A. Internal Revenue Code (IRC) section 45 states that the PTC amount must be adjusted annually for inflation. With current inflation trending much higher than average, Staff understands it is likely that the PTC will increase to 2.8 cents in 2023, suggesting that the Company's forecasted rate of 2.7 cents may be inaccurate.

Q. How did Staff determine the PTC will increase to 2.8 cents per kWh?

A. IRC Section 45 (b)(2) directs how to adjust the PTC rate annually:

> The 1.5 cent amount in subsection (a)…shall each be adjusted by multiplying such amount by the inflation adjustment factor for the calendar year in which the sale occurs. If any amount as increased under the preceding sentence is not a multiple of 0.1 cent, such amount shall be rounded to the nearest multiple of 0.1 cent.

The calculation, as shown in Staff/402, Bolton/3, requires finding the inflation adjustment factor, which is determined by dividing the GDP implicit price deflator for the year prior to the tax by the value in 1992, the year before the PTC was enacted. GDP implicit price deflators for a given year are published by the Bureau of Economic Analysis (BEA) or can be calculated by dividing the nominal GDP by the real GDP and multiplying by 100. To determine the PTC amount for 2023, Staff used the GDP implicit price deflator for quarter 1 of 2022, 123.545, and divided by the implicit price deflator for 1992, 67.282.[2] The resulting inflation adjustment factor is 1.8362. Multiplying 1.8362 by 1.5, as

2 Staff/402, Bolton/1.

directed in IRC Section 45, results in a PTC rate of 2.754 cents. However, Section 45 also notes to round to the nearest 0.1 cent, therefore the PTC rate would be 2.8 cents per kWh.

With inflation as high as 8.0 percent in Q1 of 2022, it appears unlikely for an extended period of deflation to occur in the next three quarters. Without a significant deflation event, the inflation adjustment factor will likely remain at the same level or higher throughout 2022, triggering the PTC increase calculated above.

Q. Do you have any adjustments to the Company's PTC benefits?

A. Yes. Given that Staff assumes an increase to the PTC rate will occur for 2023, the Company's PTC benefit calculation should reflect that change. With the updated PTC rate of 2.8 cents per kWh, Staff calculates the Oregon-allocated PTC benefit would be $72.8 million, an increase of $2.6 million from the Company's calculation. This would reduce NPC in the 2023 TAM by nearly $4.4 million compared to the 2022 TAM. While Staff's current recommendation is to increase the PTC rate in the calculation to 2.8 cents, it should be noted that the BEA will publish a second estimate for GDP implicit price deflator and inflation trends on May 26, 2022.[3] This second update will be based on more complete data and may provide a more accurate estimate of the potential for a PTC increase in 2023. Staff will update the calculation in further testimony if there is an opportunity to do so.

[3] BEA 22-17 News Release, *Gross Domestic Product, First Quarter,* April 28, 2022.

ISSUE 2. DIRECT ACCESS: CONSUMER OPT-OUT CHARGE

Q. What is the Consumer Opt-Out Charge?

A. Witness Michael Wilding's testimony addresses the Consumer Opt-Out Charge (COOC) on page 57, describing it as a 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 direct access load.

Q. How is the COOC calculated?

A. In the first five years, the Direct Access 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 reduces the forecasted costs back to calculate a levelized payment for years one through five.

Q. What is Staff's recommendation for purposes of this proceeding?

A. In Order No. 21-379 in UE 390, the Commission adopted Staff's recommendation to order the Company to utilize its approved methodology to calculate the COOC as a floating mechanism that can go below zero, and that is essentially a shopping credit. It is Staff's understanding that the Company has calculated the COOC consistent with the Commission's order in UE 390, as referenced in the Company's initial filing.[4] Order No. 21-379 noted that the appropriate docket to make a final determination on the COOC methodology is in UM 2024. However, since this issue has not yet been settled in UM 2024,

[4] PAC/100 Wilding/58 at line 14.

Staff understands that 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 Direct Access and Cost of Service (COS) customer classes, and until a more thorough determination can be made as part of the proceedings in UM 2024, the COOC should be able to go below zero in order to avoid a methodological bias towards subsidization of COS customers.

ISSUE 3. QUALIFYING FACILITIES

Q. Please discuss Qualifying Facilities 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 Qualifying Facilities (QFs) at rates set by the state regulatory commissions. 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. The Commission also adopted a methodology to weight the CDR by QF size beginning in the 2019 TAM.

Q. Has the Company proposed any changes to the methodology for QF costs in the 2023 TAM?

A. No. It is Staff's understanding that PacifiCorp is using the approved methodology from the 2019 TAM. Additionally, no new QFs are expected to come online in the 2023 TAM forecast period,[5] therefore there should not be an adjustment to the forecast to reflect the CDR.

Q. Has the Company continued to over-forecast QF generation?

A. Yes. Staff compared the actual and projected QF generation for 2016-2021 and determined the Company has continued to over forecast QF generation since Staff's previous findings in UE 390.[6] In 2021, PacifiCorp over forecasted

[5] PAC/100, Wilding/13.
[6] Order No. 21-379, p. 37.

by [redacted], slightly more than in the previous two years.[7] The Company's overestimate carries over to QF costs, resulting in an average percent difference of [redacted] between actual and forecasted QF power costs.[8] As noted in the Commission's Order No. 21-379 in UE 390, the cause of the over forecasting does not appear to be associated with new QFs, as the 2021 forecast should have been much more accurate due to no new QFs coming online in the 2021 or 2022 forecasts.

Q. Please explain the requirements set out by the Commission in Order No. 21-379 relating to PacifiCorp's QF forecasting?

A. Order No. 21-379 directed the Company to investigate what is causing the inaccuracies in the forecast and provide an update in the 2023 TAM filing. It also directed that PacifiCorp update Staff's table showing the percent difference between actual QF generation and forecasted QF generation. In its opening testimony, the Company noted that the update is not ready and would be included in rebuttal testimony instead. Specifically, the update can't be completed until certain information is available after the PCAM is filed in Oregon on May 15.[9]

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

A. Based on the average percent difference in forecasted QF costs compared to actuals, I recommend an adjustment by reducing total Company QF power

7 Staff/402, Bolton/2.
8 Staff/402, Bolton/2.
9 PAC/100, Wilding/53.

costs for the 2023 forecast period by [redacted]. This results in an Oregon-allocated amount of [redacted] for QF power costs and represents a [redacted] decrease in Oregon-allocated power cost. However, Staff notes that this recommendation could change following the Company's investigation on the cause of the historical overestimation for QF generation.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 400
WITNESS: MADISON BOLTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 401

Witness Qualifications Statement

May 25, 2022

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 2 in the Utility Strategy and Integration Division 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 400
WITNESS: MADISON BOLTON

PUBLIC UTILITY COMMISSION
OF
OREGON

CONFIDENTIAL STAFF EXHIBIT 402

PTC Rate Adjustment &
QF Forecast Adjustment

May 25, 2022

PTC Rate Adjustment

Table 1.1.3. Real Gross Domestic Product, Quantity Indexes
[Index numbers, 2012=100] Seasonally adjusted
Quarterly data from 1947Q1 to 2021Q3
Bureau of Economic Analysis
Data published December 22, 2021
File created Dec 20 2021 4:08PM

Line		2021Q1	2021Q2	2021Q3	2021Q4	2022Q1
1	Gross domestic product	19,055,655	19,368,310	19,478,893	19,806,300	19,735,900

Table 1.1.5. Gross Domestic Product
[Millions of dollars] Seasonally adjusted at annual rates
Quarterly data from 1947Q1 to 2021Q3
Bureau of Economic Analysis
Data published December 22, 2021
File created Dec 20 2021 4:08PM

Line		2021Q1	2021Q2	2021Q3	2021Q4	2022Q1
1	Gross domestic product	22,038,226	22,740,959	23,202,344	24,002,800	24,382,700

Implicit Price Deflator		123.5449
	GDP Implicit Price Deflator in 1992	
	67.282	
Inflation Adjustment Factor		1.836
PTC Increase		2.754
	Rounded up	2.8

Staff Adjustment Calculation

[redacted]

2.8 cents PTC Oregon allocated	$	(72,789,071.27)
Difference between Staff and Company Recovery of PTC in Rates	$	(2,599,609.69)
Adjusted Oregon allocated PTC increase	$	(4,391,151.68)
system-wide		[redacted]
	$	(210,556,169.24)
	$	(7,519,863.19)

QF Forecast Adjustment

Qualifying Facilities (Dollars ($))		2016	2017	2018	2019	2020	2021	Average
Total Qualifying Facilities	**Actual**	[redacted]						
	Forecast							

Qualifying Facilities (megawatt-hours (M		2016	2017	2018	2019	2020	2021
Total Qualifying Facilities	**Actual**	[redacted]					
	Forecast						
	% difference						

[redacted]

System wide adjustment [redacted]

CASE: UE 400
WITNESS: Brian Fjeldheim

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 500

Opening Testimony

May 25, 2022

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

A. My name is Brian Fjeldheim. I am a Senior Financial Analyst employed in the Rates, Finance, and Audit (RFA) 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 qualification statement is found in Exhibit Staff/501.

Q. What is the purpose of your testimony?

A. I provide Staff analysis and recommendations concerning PacifiCorp's modeling changes in outages methodology, summer generation thermal attributes, and regulating reserve requirement.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared the following exhibits:

Exhibit Staff/502 – Responses to Staff Data Requests.

Exhibit Staff/503 – Confidential Responses to Staff Data Requests.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. OUTAGES METHODOLOGY

Q. Please summarize Staff's review of PacifiCorp's change in outages methodology.

A. Staff's review focused primarily on the portions of testimony and supporting exhibits provided by Mr. Wilding (PAC/100-108). In his testimony, Mr. Wilding briefly addresses the Company's proposed change in the outages methodology used in the Aurora model resulting in an Oregon allocated net variable power cost (NVPC) increase of $3.62 million.[1] Staff also issued DRs 76, 77, and 82 requesting additional information concerning the outage modeling change.

Q. Please describe the Company's change in outages methodology.

A. In previous NVPC filings, PacifiCorp used a normalized four-year historical average of outages and the resulting generating capacity for each individual thermal plant to project outages in the test year.[2] Using a normalized four-year average captured routinely scheduled outages as well as any unexpected outages, while smoothing out any significant outage activity that would be unlikely to re-occur in a future test year period. In the present filing, the Company proposes to eliminate using the established normalized four-year average outage methodology and moving to a budgeted/planned thermal plant outage forecast.[3]

Q. Why is the Company proposing this change in outage methodology?

A. Per Mr. Wilding:

1 PAC/100, Wilding/35, lines 11-12.
2 PAC/100, Wilding/34, lines 10-14.
3 PAC/100, Wilding/34-35.

> Since the TAM is an annual filing, it makes sense that the planned outages would be updated annually based on the Company's budgeted outage plan for the forecast period as opposed to an historical average of planned outages. The use of budgeted planned outage schedules represents a basic improvement in data quality that will lead to increased accuracy of the NPC forecast.[4]
>
> Using budgeted planned outage schedules for thermal plants allows the model to be based on the planned outage schedules for the forecast period. This in turn allows the Aurora model to create a dispatch schedule that is reflective of PacifiCorp's planned operations based on best available information at the time of the TAM modeling instead of an average outage schedule based on historical data.[5]

Q. Does Staff agree with the Company's proposed modeling change?

A. No. It is Staff's practice to use a historical four-year average for various data components used in annual NVPC modeling. Using a normalized four-year average smooths the outage component in the model and reduces the potential for year-to-year rate "lumpiness". This smoothing effect treats customers more equitably and promotes more stable rates, rather than jumping up or down depending on where the Company is on its cycle of outage activities. Finally, continued use of a normalized four-year average reduces the opportunity for forecasting bias by using quantifiable data based upon recent actual operations for the individual thermal plants. In Staff's opinion, using a budget forecast reduces transparency in the outage model assumption(s) and renders the equivalent of a "black box" modeling input. Staff is also concerned that using a test year projection based solely upon

---

[4] *Id.*

[5] *Id.*, page 35 at lines 4-8.

scheduled outages ignores the potential of outages that differ from what the utility plans that might not otherwise be captured in the model.

Q. Did the Company provide direct evidence the proposed modeling change reduces NVPC forecasting error?

A. No. The Company provided a step change log to illustrate the respective NVPC impacts for each of the proposed modeling changes on a system basis.[6] The Company also provided a supplemental confidential Excel workpaper "SL02 Planned Outages NPC ORTAM CY2023 CONF" that calculates test year NVPC based upon the proposed budgeted/planned outage methodology. However, Staff did not identify in the supporting step log exhibit or the Company's workpaper how the $3.62 million NVPC increase represents a forecasting improvement compared to a normalized four-year average of actual Company outages. Likewise, the Company did not provide budgeting or test year outage planning documents to support how the test year forecasted outages are calculated by individual thermal plant and the associated dollar value impact to NVPC associated with the planned/budgeted outages.

Q. What does Staff recommend?

A. Staff recommends the Company continue using a normalized four-year average for outages in the NVPC 2023 test year and the proposed $3.62 million increase to NVPC be adjusted to $0. The $0 adjustment is because the four-year average value has not changed.

---

6 PAC/107, Wilding; and Excel workpaper "Exhibit PAC 107 - ORTAM23 Step Log Change_edit to proof". Step 2 in the 2023 TAM Step Log refers to the outage methodology change.

ISSUE 2. SUMMER GENERATION THERMAL ATTRIBUTES

Q. Please describe the Company's proposed modeling change for summer generation thermal attributes.

A. The Company briefly describes a reduction to summer power output capacities for thermal generation plants due to elevated temperatures during the June to September period. During the summer months, the Company states that certain thermal plants experience reduced generation capacity due to elevated temperatures and revised the 2023 NVPC model to reflect the reduced summer generation capacity of certain thermal plants. In previous NVPC filings, the Company relied upon a calculated average of historical capacity over general summer and winter periods.[7] This proposed change results in an Oregon allocated NVPC increase of $6.21 million.[8]

Q. Please summarize Staff's review of PacifiCorp's revision for summer generation thermal attributes.

A. Staff reviewed PAC/100, Wilding/37-38 and the confidential Excel work paper "ORTAM23 Thermal Attribute Updates CONF", Tab "Monthly Max Capacity Changes". Staff issued DRs 75, 77, and 81 requesting additional explanation of how this modeling change was calculated and what data was used to revise the summer month thermal plant generating capacities. I also performed independent research on internal combustion processes.

---

[7] PAC/100, Wilding/37, lines 15-23.
[8] PAC/100, Wilding/38, lines 10-11.

Q. Did the Company provide engineering studies, historical thermal plant performance data, or any other quantifiable data to support this change?

A. No. Staff did not identify any other supporting documents or workpapers accompanying the filing that supports this proposed change. The data included in the Excel file "ORTAM23 Thermal Attribute Updates CONF" is hardcoded with no source document(s) referenced and no calculations or formulas provided. Additionally, the Company did not explain why this modeling change is being made now.

Q. Has the Company provided sufficient evidence to support this change?

A. No. The Company provided less than one page of testimony to explain this proposed change and the Excel file accompanying the filing lacks sufficient details necessary to conclude the change in methodology is reasonable or warranted.

Q. What does Staff recommend?

A. Due to the paucity of supporting evidence in the filing, Staff recommends the Company continue using the prior method of average historical capacity over general summer and winter periods in the NVPC 2023 test year and the proposed $6.21 million increase be adjusted to $0.

ISSUE 3. REGULATING RESERVE REQUIREMENT

Q. Please describe the Company's proposed modeling change for regulating reserve requirement.

A. In the prior NVPC filing, the Company utilized a one percent Loss of Load Event (LOLE) expressed in hours per year to calculate the required regulating reserve requirement, in line with the standard included in the Company's 2019 Oregon Integrated Resource Plan (IRP).[9] In the 2023 NVPC filing, concurrent with the Company's 2021 Oregon IRP filing, the Company proposes to transition to a LOLE of 30 minutes per year. This transition results in a $17.58 million increase in the test year, primarily due to increased costs associated with market power purchases.[10]

Q. What is regulating reserve requirement?

A. Per Mr. MacNeil:

> Regulation reserves are intended to cover deviations between forecasted load and resources and actual load and resources, and represent intra-hour flexible resources necessary to comply with applicable reliability standards that wouldn't otherwise be captured within an hourly production cost model. The methodology produces hourly reserve requirement values for the PacifiCorp East (PACE) and PacifiCorp West (PACW) balancing authority areas (BAAs) that are specific to the portfolio of resources in the 2023 TAM study period.[11]
>
> In order to ensure reliable operation of the bulk electric system, PacifiCorp must continuously balance the load demand and generation output within the PACE and PACW BAAs. Regulation reserve is a component of operating reserve, which NERC defines as "the capability above firm system demand required to provide for regulation, load

---

[9] PAC/100, Wilding/33, lines 8-21.
[10] PAC/100, Wilding/33-34.
[11] PAC/300, MacNeil/2, lines 8-15.

> forecasting error, equipment forced and scheduled outages and local area protection." Regulation reserve is capacity that PacifiCorp holds available to ensure compliance with the NERC Control Performance Criteria in BAL-001-2.4.[12]

Q. How does the Company calculate regulation reserve requirements necessary to comply with NERC's BAL-001-2.4 requirements?

A. Per Mr. MacNeil:

> The calculations used to determine the regulation reserve required to ensure PacifiCorp's compliance with BAL-001-2 are described in more detail below. The five primary elements of the calculation are as follows.
> - Collection of data and historical deviations;
> - Compliance Requirements;
> - Acceptable Deviations: Historical Balancing Authority ACE Limit Data;
> - Planning Reliability Target: Loss of Load Probability (LOLP); and
> - Regulation Reserve Forecast.[13]

Q. How does the Company collect data and determine historical deviations?

A. PacifiCorp participates in the Western Energy Imbalance Market (EIM) and produces five-minute deviation data for each Company generating resource. This deviation data is then submitted to the California Independent System Operator (CAISO). The deviations are then used to determine Company imbalance charges or payments for each Company resource. For the 2023 NVPC filing, the Company utilized EIM deviation results from 2018-2019.[14] Additionally, the Company noted that it includes the full range of weather

---

12 PAC/300, MacNeil/4-5.
13 PAC/300, MacNeil/7-8.
14 PAC/300, MacNeil/8, lines 8-17.

conditions from the study period and made no adjustments for abnormal weather conditions, per compliance guidelines stated in FERC's Order No. 764 at page 321. The Company further states that inclusion of abnormal weather events serves to more accurately predict the full range of weather events the Company can expect to face on a going forward basis.[15]

Q. Why is the inclusion of abnormal weather conditions significant?

A. The Company's states that "[t]he full range of weather conditions experienced during the study period remain in the source data, as these conditions are indicative of the range of weather conditions PacifiCorp expects to experience going forward."[16] If past weather conditions are believed to be an accurate barometer of expected future weather conditions, it stands to reason that more recent weather data would be a better predictor of future weather events. In Staff DR 071, Staff inquired why the Company did not use more recent weather data, and what the impact to the 2023 NVPC cost would be if more recent weather data were used.

Q. Did the Company make any significant changes or adjustments to historical data?

A. Yes. The Company noted two adjustments:

[15] PAC/300, MacNeil/10, lines 2-9.
[16] PAC/300, MacNeil/10, lines 4-6.

1. The Company adjusted historical load data to better reflect base schedule ramping from hour to hour in the Company's area control error (ACE) calculation.[17] This is summarized in Figure 1 of Mr. MacNeil's testimony.[18]
2. The Company made adjustments for wind curtailment events by adding back curtailed wind volumes to actual meter outputs to adjust regulation reserve requirement shortfalls.[19]

Q. How does the Company determine reliability compliance requirements?

A. The Company calculates a minimum five-minute imbalance for each 30-minute rolling period in a study period. The Company then selects the maximum five-minute imbalance for each hour. Per NERC's BAL-001-2 standard, a balancing authority may not exceed the specified ACE limit for more than 30 consecutive minutes. The Company is compliant so long as the Company operates within the ACE limit at least once in each rolling 30-minute interval.[20]

Q. How does the Company determine acceptable deviations?

A. Per Mr. MacNeil:

> The Balancing Authority ACE Limit is specific to each BAA and is dynamic, varying as a function of interconnection frequency. When WECC frequency is close to 60 hertz (Hz), the Balancing Authority ACE Limit is large and large deviations in ACE are allowed. As WECC frequency drops further and further below 60 Hz, ACE deviations are increasingly restricted for BAAs that are contributing to the shortfall, i.e., those BAAs with Net Actual Interchange less than Net Scheduled Interchange. A BAA commits a BAL-001-2 reliability violation if

---

[17] PAC/300, MacNeil/9, lines 3-14.
[18] PAC/300, MacNeil/10, line 1.
[19] PAC/300, MacNeil/11, lines 11-22.
[20] PAC/300, MacNeil/12, lines 1-13.

> in any 30-minute interval it does not have at least one minute when its ACE is within its Balancing Authority ACE Limit.[21]
>
> To limit the size and speed of resource deployment necessitated by variation in the Balancing Authority ACE Limit, PacifiCorp's operating practice caps permissible ACE at the lesser of the Balancing Authority ACE Limit or four times L_{10}. L_{10} represents a bandwidth of acceptable deviation under the former BAL-001 standard (BAL-001-1) prescribed by WECC between the net scheduled interchange and the net actual electrical interchange of PacifiCorp's BAAs.[22]

Q. Did Staff note any concerns with regard to the Company's inclusion of L_{10} from the former BAL-001 standard (BAL-001-1) in determining acceptable deviations?

A. Yes. Staff noted inclusion of L_{10} may be inappropriate as it pertains to a standard the Company refers to as "former". Staff DR 073 requested the Company clarify whether L_{10} has been appropriately included in the Company's determination of acceptable deviations.

Q. How does the Company address loss of load probability (LOLP) for planning reliability target?

A. Per Mr. MacNeil:

> An electric system using a 1-day-in-10 years [Loss of Load Probability][23] will plan its system to maintain sufficient capacity (i.e., through a planning reserve margin) such that system peak load is not likely to exceed available supply (i.e., load is lost) more than once in a 10-year period. If the system is planned correctly under this metric, the electric system is considered to be a "reliable" system and the probability of load

[21] PAC/300, MacNeil/13-14.
[22] PAC/300, MacNeil/14, lines 13-18.
[23] Per PAC/300, MacNeil/17, 17-20: "LOLH is a count of the expected (mean) number of hours in which load exceeds available resources over the course of a given year. Hypothetically, a system using the 1-day-in-10-years LOLP can meet that standard by planning its system to ensure that load does not exceed generation during more than 2.4 hours per year."

> exceeding supply becomes highly improbable. However, the 1-day-in-10-years planning standard accepts that in a reliably planned electric system, firm load might be curtailed in rare circumstances, rather than acquiring resources for extremely unlikely events. Under the most-restrictive interpretation,1-day-in-10-years would require reliable operation for nine years and 364 days out of a 10-year period, and would allow capacity shortfalls to occur on a single day. Under a less-restrictive interpretation, one day can be expressed as 24 hours, which would allow capacity shortfalls to occur in up to 24 hours spread across 10 years. PacifiCorp's analysis uses this less-restrictive "loss of load hours" interpretation.[24]

Q. How did the Company determine the Regulation Reserve Forecast?

A. Per Mr. MacNeil:

> The regulation reserve requirement is first compared to the hourly compliance requirement to determine the magnitude of the shortfall in each hour, if any. Next, the LOLP associated with each hour that has a shortfall is calculated from the Balancing Authority ACE Limit probability distribution. Finally, if the cumulative LOLP over all hours with shortfalls in the year is less than the reliability target, the regulation reserve requirement is deemed sufficient to comply with BAL-001-2.[25]

On a stand-alone basis, the Company's Regulation Reserve Requirement Forecast is 1,057 aMW.[26] Because the Company utilizes a diverse power generation portfolio, the Company is able to reduce its required regulatory reserve requirements. Per Mr. MacNeil:

> The stand-alone regulation reserve forecasts described above (459 MW for wind, 160 MW for solar, 107 MW for Non-VERs, and 336 MW for load) independently ensure that the probability of a reliability violation for load and each resource type remains within the reliability target. However, the largest deviations tend not to occur simultaneously, and in some cases load and different resources will have offsetting

[24] PAC/300, MacNeil/17, lines 2-15.
[25] PAC/300, MacNeil/20, lines 15-20.
[26] PAC/300, MacNeil/27, line 5, Table 1: Summary of Stand-alone Regulation Reserve Requirements.

> deviations. As a result, while the sum of the stand-alone reserve requirements yields a total reserve requirement of 1057 MW, the total portfolio requirement when all deviations are combined is only 679 MW. This 36 percent reduction in the reserve requirement still achieves the reliability target of 0.50 LOLH per year. Because the regulation reserves held cover the expected deviations for multiple sources at once, a reduced total quantity of reserves is sufficient to maintain the desired level of reliability.[27]

As an active participant in the EIM, the Company receives an EIM diversity benefit when determining its regulation reserve requirement. In the 2023 NVPC filing, the EIM diversity benefit further reduces the average reserve requirement by 20 percent, resulting in an average regulation reserve requirement of 540 MW (as compared to the stand-alone reserve requirement of 1,057 MW).[28]

Q. Does Staff have any concerns with the Company's treatment or calculation of regulation reserve requirement?

A. Yes. On May 10, 2022, the Company filed a notice of correction or omissions. In particular, the Company noted an Aurora input correction for regulating reserve requirement values. The Company further stated this is a technical adjustment and does not affect the underlying methodology and will be addressed in the Company's reply testimony. Staff also raised one concern regarding the Company's regulation reserve requirement calculation. Staff noted that in PAC/300, MacNeil/17-18, the Company used several differing values for the LOLH reliability metric (2.4, 1.06, and 0.50 hours). Staff issued

---

[27] PAC/300, MacNeil/28, lines 3-14.
[28] PAC/300, MacNeil/30, lines 3-6.

DR 074 to request additional clarification as to which value(s) should be used and why multiple value were referenced.

Q. What does Staff recommend?

A. Due to the Company's May 10 notification that an error/omission exists in the filed NVPC amount for regulation reserve requirement, Staff is unable to determine whether an adjustment is warranted to the Company's proposed $17.58 million increase for the 2023 TAM. Staff reserves the right to make an adjustment in a later round of testimony after having the opportunity to review the Company's updated NVPC projection in Reply Testimony related to regulation reserve requirement.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 400
WITNESS: Brian Fjeldheim

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 501

Witness Qualification Statement

Exhibits in Support
Of Opening Testimony

May 25, 2022

WITNESS QUALIFICATION STATEMENT

NAME:	Brian Fjeldheim
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Financial Analyst Energy Rates, Finance and Planning Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	Bachelor of Science, Business Accountancy Regis University, Denver, CO Bachelor of Science, Aviation Technology Metropolitan State College of Denver, Denver, CO
EXPERIENCE:	I have been employed as a Senior Financial Analyst by the Oregon Public Utility Commission since May of 2018 in the Rates, Finance, and Audit Division. I currently perform a range of financial analysis duties related to natural gas and electric utilities, with a focus on rate case, operational audit, and annual Purchased Gas Adjustment (PGA) filings. I have participated in utility general rate cases and power cost filings in the following dockets: Cascade Natural Gas – UG 347, Avista Utilities – UG 366, NW Natural – UG 388, PacifiCorp – UE 374, Avista Utilities – UG 389, Cascade Natural Gas – UG 390, PacifiCorp – UE 390, PGE – UE 391, PGE – UE 394, Avista Utilities – UG 433, NW Natural – UG 435, PacifiCorp – UE 399, PacifiCorp – UE 400, and PGE – UE 402. I have nine years of professional level financial analysis and accounting experience. I was previously employed as a Budget and Fiscal Analyst with the Oregon Department of Justice (DOJ), where I was responsible for the budget build and ongoing budget execution of four legal divisions with 165 staff members and a biennial budget of $75 million. Prior to DOJ, I was employed as a Senior Budget Analyst with the Oregon Department of Administrative Services (DAS) and was responsible for the budget build, ongoing budget execution and cash flow analysis for the state data center with a biennial budget of $165 million. Prior to DAS, I worked as a Financial Analyst for the Insurance Division of the Department of Consumer and Business Services (DCBS), where I performed financial analysis and solvency surveillance of nine Oregon insurers with annual revenues of $1.4 billion and assets of $1.1 billion.

CASE: UE 400
WITNESS: Brian Fjeldheim

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 502

Exhibits in Support
Of Opening Testimony

May 25, 2022

UE 400 / PacifiCorp
May 11, 2022
OPUC Data Request 71

OPUC Data Request 71

Regulating Reserve Requirement - In reference to PAC/300, MacNeil/2 at 18-20, regarding the selection of 2018-2019 historical results for deviation information for load and various resource types:

(a) Please explain why 2018-2019 historical data was selected versus using data from a more recent time period?

(b) What would the rate impact to customers be if 2019-2020 were used?

(c) What would the rate impact to customers if 2020-2021 were used?

(d) What would be the dollar and rate impact if 2018-2021 data were used?

Response to OPUC Data Request 71

(a) Data for the historical period 2018 and 2019 was the most recent data available at the time the study was prepared in 2020, which was at the start of the development of PacifiCorp's 2021 Integrated Resource Plan (IRP).

(b) The Company has not compiled deviation data for other periods and has therefore not prepared the requested information / analysis.

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

(d) Please refer to the Company's response to subpart (b) above.

UE 400 / PacifiCorp
May 11, 2022
OPUC Data Request 72

OPUC Data Request 72

Regulating Reserve Requirement – In reference to PAC/300, MacNeil/8 at 16-17 and MacNeil/10 at 2-9, regarding the inclusion of abnormal weather conditions in the EIM deviation study period data:

(a) Please further explain how inclusion of extreme and/or abnormal weather events enhances the modeling accuracy on a going forward basis.

(b) If the Company deems recent weather data, to include extreme and/ or abnormal events, to be an accurate barometer of future weather trends, why not use data from a more recent period, such as 2019-2020 or 2020-2021?

(c) What would be the rate impact to customers if 2019-2020 weather data were used?

(d) What would be the rate impact to customers if 2020-2021 weather data were used?

(e) What would be the dollar and rate impact if 2018-2021 weather data were used?

Response to OPUC Data Request 72

(a) The Company is obligated to comply with applicable reliability standards under all weather conditions, so including only normal conditions would not result in sufficient regulation reserve capability in actual operations.

(b) Data for the historical period 2018 and 2019 was the most recent data available at the time the study was prepared in 2020, which was at the start of the development of PacifiCorp's 2021 Integrated Resource Plan (IRP).

(c) The Company has not compiled deviation data for other periods and has therefore not prepared the requested information / analysis.

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

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

UE 400 / PacifiCorp
May 11, 2022
OPUC Data Request 73

OPUC Data Request 73

Regulating Reserve Requirement – In reference to PAC/300, MacNeil/14 at 13-18, regarding the Company's determination of permissible Balancing Authority ACE Limit:

(a) Has the WECC prescribed BAL-001-1 bandwidth acceptable deviation L_{10} been superseded?

(b) If yes to a. above, what standard is now used in place of BAL-001-1?

(c) Please explain why is L_{10} still used in the Company's determination of permissible ACE.

(d) If L_{10} were excluded from the Company's calculation for Balancing Authority ACE Limit, what impact would that have on NVPC?

Response to OPUC Data Request 73

(a) Yes.

(b) Western Electricity Coordinating Council (WECC) / North American Electric Reliability Corporation (NERC) standard BAL-001-1 (Real Power Balancing Control Performance) was made inactive June 30, 2016 and replaced by WECC / NERC standard BAL-001-2 (Real Power Balancing Control Performance).

(c) The Balancing Authority (BA) Area Control Error (ACE) Limit is tied to interconnection frequency, which can change significantly over the course of a few seconds. Four times L_{10} is at the high end of the Company's current ramping capability, so the Company would have difficulty timely bringing the system back into compliance if the deviations exceeded this level.

(d) If the Company did not cap the permissible BA ACE Limit as described, the impact on regulation reserve requirements would be negligible at a target threshold of 0.5 hours per year. As shown in the direct testimony of Company witness, Daniel J. MacNeil, Exhibit PAC/300 MacNeil/15, Figure 2, the cap is reflected where the PacifiCorp East (PACE) and PacifiCorp West (PACW) probability of exceeding the allowed deviation becomes vertical (no deviations are allowed beyond that point). For both PACE and PACW, this is at a level greater than 50 percent, or 0.5 hours per deviation event. As a result, any deviation that exceeded the cap would already have exceeded the annual target threshold on its own, cap or no.

UE 400 / PacifiCorp
May 11, 2022
OPUC Data Request 74

OPUC Data Request 74

Regulating Reserve Requirement – In reference to PAC/300, MacNeil/17-18, concerning the one-day-in-ten-years loss of load hours (LOLH) reliability metric:

(a) Does PacifiCorp's use of the "less restrictive" LOLH interpretation of 2.4 hours per year result in a lower NVPC rate charged to customers? If no, why is the less restrictive interpretation used?

(b) There are several different values referenced for LOLH (2.4 hours, 0.50 hours, and 1.06 LOLH per year). If 2.4 hours LOLH a year is representative of a "reliable" electric system, please explain why the Company also uses the lower 0.50 hours and 1.06 hours LOLH per year metrics to determine regulation reserve requirements?

Response to OPUC Data Request 74

(a) From a capacity planning perspective, the Company's use of a 2.4 hour per year target would consider a portfolio reliable if shortfall events with duration of eight hours each were expected to occur in three out of 10 years (24 hours in 10 years, or 2.4 hours per year). Under a one day in 10 years target, additional resources would need to be added to eliminate two of the three shortfall events, such that only one day in 10 years experienced any events. These incremental resources would result in higher customer rates to achieve the higher level of system reliability.

(b) 1.06 loss of load hours (LOLH) represents the probability of shortfalls due to resource adequacy, namely the chance that a combination of a hot summer, dry hydro conditions, and above average forced outages would leave insufficient resources for the Company to serve load and meet its operation reserve obligations. This is calculated using an hourly model, therefore, it does not capture intra-hour variation. The regulation reserve requirement based on a 0.5 LOLH only represents intra-hour forecast error relative to a forecast made in the prior hour, and not the other factors, which would impact many hours in a row. As a result, there is little or no overlap between these two sources of uncertainty and they would be additive. Because customers are agnostic to the cause of their power being shutoff, the combined risk from both types of events should not exceed the target of 2.4 hour per year.

UE 400 / PacifiCorp
May 11, 2022
OPUC Data Request 75

OPUC Data Request 75

Thermal attributes for summer generation - In reference to PAC/100, Wilding/37-38, regarding the change to maximum thermal generation output for the months of June through September:

(a) Please indicate the work paper(s) accompanying the filing used to determine the revised summer maximum output.

(b) Please indicate all testimony and exhibits in the Company's filing supporting the revised summer maximum output.

(c) Please indicate the affected thermal generation plants.

(d) Please provide the original and revised summer generation outputs, by month, for each affected thermal plant in an Excel file.

(e) Please provide the work paper(s) supporting the Company's $6.21 million increase to the NVPC resulting from increased market purchases.

Response to OPUC Data Request 75

(a) Please refer to the Company's responses to TAM Support Set 2 (5-business day), specifically confidential work paper "Input Files\Thermal Data\Aurora GNw Resource Table Thermal CONF.xlsx", tab "mn_x".

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

(c) The thermal units affected by this summer derate are:

Chehalis, Currant Creek (including the duct-fired unit), Wyodak, Lake Side 1 (including the duct-fired unit), Lake Side 2 (including the duct-fired unit), Dave Johnston Unit 1, Dave Johnston Unit 2, Hermiston Unit 1 and Hermiston Unit 2.

(d) Please refer to Confidential Attachment OPUC 75.

(e) Please refer to the Company's responses to TAM Support Set 1 (concurrent"), specifically confidential work paper "SL04 Market Caps CONF.xlsx", tab "NPC Summary", cell D310, and confidential work paper "SL05 Thermal Attribute CONF.xlsx", tab "NPC Summary", cell D310. The difference between the two values, when multiplied by Oregon allocation, results in a $6.21 million increase. Additionally, please refer to the two confidential work papers referenced above to support the increase in market purchases.

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 400 / PacifiCorp
May 17, 2022
OPUC Data Request 76

OPUC Data Request 76

Generation outage modeling - In reference to PAC/100, Wilding/10 at 10-11; 27 at 5-6; and 34-35, regarding the change in outage modeling from the current four historical average data to budgeted and/or planned outages:

(a) Please provide further explanation how a budgeted/future estimate for generation outages is superior to the existing modeling methodology.

(b) Please provide a comparison of 2019 actual outages to the four year (2015-2018) historical average and the 2019 budgeted/projected outages.

(c) Please provide a comparison of 2020 actual outages to the four year (2016-2019) historical average and the 2020 budgeted/projected outages.

(d) Please provide a comparison of 2021 actual outages to the four year (2017-2020) historical average and the 2021 budgeted/projected outages.

(e) Please provide the electronic work paper(s), with all cell references and formulas intact, used to calculate the $3.62 million increase in NVPC.

Response to OPUC Data Request 76

(a) Please refer to the direct testimony of Company's witness, Michael G. Wilding, page 35.

(b) The Company notes that the four-year historical average outage data is derived from the relevant Transition Adjustment Mechanism (TAM) proceedings, specifically the 2019 TAM, Docket UE-339, the 2020 TAM, Docket UE-356, and the 2021 TAM, Docket UE-390. Based on the foregoing understanding, the Company responds as follows:

Please refer to Confidential Attachment OPUC 76. The "Comparison" tab in this attachment shows a comparison between historical, actual and budgeted outages. This tab has been divided to show the number of hours a unit was on outage across the aforementioned categories along with the megawatt-hours (MWh) lost during these outages.

Note: when considering the historical averages in tab "Comparison", the unit type needs to be considered as this plays a role in the planned outage average. With the coal units, typically only one coal unit is on outage for a given year in a four-year historical average; thus contributing to a lower historical average than the actual and budgeted outages. If adding the total of the average historical for a coal unit, the result will be closer to the actual and budgeted outages for that unit. With natural gas units, the four-year average contains outages that are not symmetrical in length, therefore, when the average is rendered, the historical four-year average is going to be higher than the actual and budgeted outages.

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

(d) Please refer to the Company's response to subpart (b) above.

(e) Please refer to the Company's responses to TAM Support Set 1 (concurrent), specifically confidential work paper "SL01 Regulating Margin CONF.xlsx", tab "NPC Summary", cell D310, and confidential work paper "SL02 Planned Outages CONF.xlsx", tab "NPC Summary", cell D310. The difference between the two values, when multiplied by Oregon allocation, results $3.62 million increase to net power costs (NPC).

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 400 / PacifiCorp
May 11, 2022
OPUC Data Request 77

OPUC Data Request 77

Step log changes - Regarding the PacifiCorp Excel work paper "Exhibit PAC 107 - ORTAM23 Step Log Change_edit to proof", Tab "Step Log":

(a) Please indicate the supporting work paper(s) included with the filing supporting the Step 1 - Regulating Reserve Requirement modeling change resulting in the $67.465 million NVPC increase. Please identify the specific workbooks, tabs, and Excel cell references used to calculate this dollar amount.

(b) Please indicate the supporting work paper(s) included with the filing supporting the Step 2 - Planned Outages modeling change resulting in the $13.893 million NVPC increase. Please identify the specific workbooks, tabs, and Excel cell references used to calculate this dollar amount.

(c) Please indicate the supporting work paper(s) included with the filing supporting the Step 5 - Thermal Attributes Update modeling change resulting in the $23.830 million NVPC increase. Please identify the specific workbooks, tabs, and Excel cell references used to calculate this dollar amount.

Response to OPUC Data Request 77

(a) Please refer to the Company's response to TAM Support Set 1 (concurrent), specifically confidential work paper "SL01 Regulating Margin CONF.xlsx", tab "NPC Summary", cell D309, and the Company's response to OPUC Data Request 70, specifically Confidential Attachment OPUC 70, specifically tab "NPC Summary", cell D309. The difference between the two values results in a $67.465 million increase to net power costs (NPC).

(b) Please refer to the Company's responses to TAM Support Set 1 (concurrent), specifically confidential work paper "SL01 Regulating Margin CONF.xlsx", tab "NPC Summary", cell D310, and confidential work paper "SL02 Planned Outages CONF.xlsx", tab "NPC Summary", cell D310. The difference between the two values results in a $13.893 million NPC increase.

(c) Please refer to the Company's responses to TAM Support Set 1 (concurrent), specifically confidential work paper "SL04 Market Caps CONF.xlsx", tab "NPC Summary", cell D310, and confidential work paper "SL05 Thermal Attribute CONF.xlsx", tab "NPC Summary", cell D310. The difference between the two values results in a $23.83 million NPC increase.

UE 400 / PacifiCorp
May 11, 2022
OPUC Data Request 78

OPUC Data Request 78

Regulating Reserve Requirement - In reference to PAC/100, Wilding/33 at 17-23, regarding PacifiCorp's Regulation Reserve Requirement modeling change from one percent Loss of Load Event (LOLE) to a LOLE of 30 minutes per year:

(a) Did the Company engage with the Commission in any other docket or forum prior to this filing concerning this change?

(b) If yes to a. above, please provide references to dockets numbers, copies of communications, presentations, work papers, and other relevant documentation.

Response to OPUC Data Request 78

(a) Yes.

(b) PacifiCorp's regulation reserve requirements reflect assumptions developed in support of the Company's 2021 Integrated Resource Plan (IRP), published in October 2021 and filed with the Public Utility Commission of Oregon (OPUC) in Docket LC-77. Work papers supporting PacifiCorp's 2021 IRP were also provided on confidential and non-confidential / public data disks also filed with the OPUC in Docket LC-77. Work papers specific to PacifiCorp's regulation reserve requirements are provided on the confidential data disk supporting the 2021 IRP, specifically folder "Chapters and Appendices/Appendix F Flexible Reserve Study", and the non-confidential / public data disk supporting the 2021 IRP, specifically folder "Chapters and Appendices/Appendix F Flexible Reserve Study". For ease of reference, please refer to Confidential Attachment OPUC 78-1 and Attachment OPUC 78-2 which provide copies of the above referenced folders from PacifiCorp's 2021 IRP data disks.

The Company's 2021 IRP is publicly available and can be accessed by utilizing the following website link:

Integrated Resource Plan (pacificorp.com)

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. Note: these attachments do not contain commercially sensitive project-specific information.

UE 400 / PacifiCorp
May 11, 2022
OPUC Data Request 79

OPUC Data Request 79

Regulating Reserve Requirement - In reference to PAC/300, MacNeil/2 at 18-20, regarding the selection of 2018-2019 historical results for deviation information for load and various resource types:

(a) Please indicate which work paper(s) were used to make this calculation, to include specific references to workbooks, tabs, cell references, and calculations. If the work paper(s) question were not provided in this filing, please submit all relevant work papers and datasets necessary to complete this calculation.

(b) Please provide all data that would be used to make this calculation for 2017-2021.

Response to OPUC Data Request 79

(a) Deviation information for load and various resources was included with the non-confidential work papers supporting the direct testimony of Company witness, Daniel J. MacNeil, specifically folder "Calculations". There are eight files with deviation-related information, each starting with either "PACE" or "PACW", and ending with a type, specifically Load, Wind, Solar, or Non-VER (non-variable energy resources). These files contain data for the 2018-2019 study period. The data points include:

- Hour-ahead forecasts (hourly granularity, column D, "Base_Schedule").
- Actual metered results (five-minute granularity, column E, "Meter").
- Adjusted hour-ahead forecasts, with hour to hour ramping (five-minute granularity, column K, "Base_Schedule_Ramp"). This adjustment is a linear ramp starting 10 minutes prior to each hour and ending 10 minutes after each hour, consistent with existing operational practices.
- Deviations (five-minute granularity, column F, e.g. "PACE.Load.Error"). Deviations represent the difference between column E and column K.

For additional descriptions of the non-confidential work papers, please refer to Attachment OPUC 79-1.

(b) For deviation information for 2017, please refer to Confidential Attachment OPUC 79-2, which was used to support PacifiCorp's 2019 Integrated

Resource Plan (IRP) Flexible Reserve Study (FRS). The Company has not compiled the referenced data for other periods.

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 400 / PacifiCorp
May 11, 2022
OPUC Data Request 80

OPUC Data Request 80

Regulating Reserve Requirement - In reference to PAC/300, MacNeil/8 at 16-17 and MacNeil/10 at 2-9, regarding the inclusion of abnormal weather conditions in the EIM deviation study period data:

(a) Please provide the weather data for the past 10 years.

Response to OPUC Data Request 80

(a) The Company has not prepared the requested information. Weather conditions are implicit in the deviation results identified in the Company's response to OPUC Data Request 79.

UE 400 / PacifiCorp
May 12, 2022
OPUC Data Request 81

OPUC Data Request 81

Thermal attributes for summer generation - In reference to PAC/100, Wilding/37-38, regarding the change to maximum thermal generation output for the months of June through September:

(a) Please provide a narrative response explaining why the reduced June through September maximum outputs were not previously noted.

(b) Were all work paper(s) used to complete the analysis of the revised summer maximum output included with the filing? If no, please provide them in response to this question, noting specific workbooks, tabs, cell references, and equations used in the Company's determination.

Response to OPUC Data Request 81

(a) The maximum thermal generation output are constraints on the actual generation units and have always existed. Over the past two years, PacifiCorp has been able to work with the thermal plants to develop more precision around these constrains and incorporate that precision into real-time operations. With the increased precision in real-time operations, PacifiCorp has proposed to incorporate these inputs into the net power costs (NPC) forecast so the forecast better reflects the actual operational constraints on those units. This approach helps the Company better align its NPC forecasting with operational reality.

(b) Please refer to Confidential Attachment OPUC 81.

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 400 / PacifiCorp
May 17, 2022
OPUC Data Request 82

OPUC Data Request 82

Generation outage modeling - In reference to PAC/100, Wilding/10 at 10-11; 27 at 5-6; and 34-35, regarding the change in outage modeling from the current four historical average data to budgeted and/or planned outages:

(a) Please provide the most recent 10 years of data for budgeted and planned outages, showing each separately.

(b) Please provide the most recent 10 years of data for actual outages, showing budgeted, planned, and forced outages separately.

(c) How does the Company treat thermal plant derations?

Response to OPUC Data Request 82

The Company assumes that based on the referenced testimony that this request is for outage data for PacifiCorp's owned thermal generating resources. The Company also clarifies that, as part of the North American Electric Reliability Corporation (NERC) Generating Availability Data System (GADS) compliance, outages that actually occurred are classified as either: planned outages (which are outages that are specifically scheduled well in advance for a pre-determined duration), maintenance outages or forced outages (which are outages that occur throughout the year and are classified based on how soon the unit must be taken off-line, from immediately to beyond the end of the next weekend). The Company further clarifies that "budgeted" outages refers to those outages which the Company is anticipating will occur in a future period, for planning purposes. Note: "the most recent 10 years of data" at this time is calendar year 2012 through 2021.

(a) Please refer to Confidential Attachment OPUC 82-1 which provides the Company's budgeted outages for calendar years 2012 through 2021.

(b) Please refer to Confidential Attachment OPUC 82-2 which provides data on actually occurred planned outages, maintenance outages and / or forced outages for the Company's owned thermal generating resources for calendar years 2012 through 2021.

(c) The Company assumes that this request is asking about the modeling of planned outages in the 2023 transition adjustment mechanism (TAM) 2023. Based on the foregoing assumption, the Company responds as follows:

Please refer to the Company's responses to TAM Support Set 2 (5-business day), specifically confidential work paper "Input Files\Thermal Data\Aurora

GN Maintenance Schedule CONF.xlsx”, tab “1 Maint_Schedule”, rows 76-104.

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 400
WITNESS: Brian Fjeldheim

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 503
Confidential -
Subject to Protective Order 16-128

Exhibits in Support
Of Opening Testimony

May 25, 2022

UE 400 / PacifiCorp
May 11, 2022
OPUC Data Request 70

OPUC Data Request 70

Regulating Reserve Requirement - In reference to PAC/100, Wilding/33 at 17-23, regarding PacifiCorp's Regulation Reserve Requirement modeling change from one percent Loss of Load Event (LOLE) to a LOLE of 30 minutes per year:

(a) Has the proposed change in LOLE been acknowledged or otherwise approved in the Company's 2021 Oregon IRP?

(b) If no to a. above, under what authority does the Company propose to deviate from the one percent LOLE modeling criteria approved in the 2019 Oregon IRP?

(c) Please indicate all Company work papers, to include specific workbook name(s) and cell references, used to support the $17.58 million increase for Regulating Reserve Requirement in the 2023 OR TAM net power cost (NPC) filing.

(d) If the work papers referred to c. above were not provided in Excel format, please submit the pertinent Excel work papers with cell references and formulas intact.

Confidential Response to OPUC Data Request 70

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

UE 400 / PacifiCorp
May 11, 2022
OPUC Data Request 70

[redacted]

[redacted]

[redacted]

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 400
WITNESS: Brian Fjeldheim

Confidential Staff Exhibit

"Relevant attachment to PacifiCorp's response to Staff DR 070"

is

filed in electronic format

CASE: UE 400
WITNESS: Brian Fjeldheim

Confidential Staff Exhibit

"Relevant attachment to PacifiCorp's response to Staff DR 075"

is

filed in electronic format

CASE: UE 400
WITNESS: Brian Fjeldheim

Confidential Staff Exhibit

“Relevant attachment to PacifiCorp’s response to Staff DR 076”

is

filed in electronic format

CASE: UE 400
WITNESS: Brian Fjeldheim

Confidential Staff Exhibit

"Relevant attachment to PacifiCorp's response to Staff DR 078-1"

is

filed in electronic format

CASE: UE 400
WITNESS: Brian Fjeldheim

Confidential Staff Exhibit

"Relevant attachment to PacifiCorp's response to Staff DR 079-2"

is

filed in electronic format

CASE: UE 400
WITNESS: Brian Fjeldheim

Confidential Staff Exhibit

"Relevant attachment to PacifiCorp's response to Staff DR 081"

is

filed in electronic format

CASE: UE 400
WITNESS: Brian Fjeldheim

Confidential Staff Exhibit

"Relevant attachment to PacifiCorp's response to Staff DR 082-1"

is

filed in electronic format

CASE: UE 400
WITNESS: Brian Fjeldheim

Confidential Staff Exhibit

"Relevant attachment to PacifiCorp's response to Staff DR 082-2"

is

filed in electronic format

CASE: UE 400
WITNESS: Steve Storm

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 600

Opening Testimony

May 25, 2022

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

A. My name is Steve Storm. I am a Senior Economist employed in the Rates, Finance and Audit 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 qualification statement is found in Exhibit Staff/601.

Q. What is the purpose of your testimony?

A. My testimony discusses certain aspects of PacifiCorp's annual Transition Adjustment Mechanism (TAM) filing related to coal-fueled generation plants, including information required by prior Commission Orders.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Exhibit Staff/601, consisting of one page and highly confidential Exhibit Staff/602, consisting of one page.

Q. How is your testimony organized?

A. My testimony is organized as follows:

SUMMARY OF REQUIREMENTS FROM PRIOR TAM PROCEEDINGS REGARDING PACIFICORP'S COAL-FUELED GENERATING PLANTS

Q. What requirements from the 2021 Transition Adjustment Mechanism (TAM) Order do you address?

A. Order No. 20-392 in the UE 375 2021 TAM proceeding adopted the Stipulation between Parties.[1] PacifiCorp agreed to "provide testimony in the initial TAM or other NPC forecast filing regarding the prudence of any Coal Supply Agreements (CSA) that were entered into after its reply testimony of the previous year's NPC forecast proceeding."[2]

Q. Did Order No. 21-379 in the 2022 TAM expand upon this requirement?

A. Yes. The Commission directed PacifiCorp to provide, in future TAMs, additional information that the Commission found necessary to facilitate parties' review of new CSAs and to evaluate the Company's management of established CSAs.[3]

Q. Are there any new CSAs discussed in PacifiCorp's Direct Testimony in the proceeding at hand, in conformance with the Stipulation in UE 375?

A. Yes. PacifiCorp states that the Company has, subsequent to the 2022 TAM, entered into a new CSA for the Naughton plant and discusses this new CSA in its Direct Testimony.[4] I discuss the new Naughton CSA as Issue 1.

---

[1] *In the Matter of PacifiCorp, dba Pacific Power, 2021 Transition Adjustment Mechanism*, Docket No. UE 375, Order No. 20-392, page 10.
[2] Id., Appendix A, page 6.
[3] *In the Matter of PacifiCorp, dba Pacific Power, 2022 Transition Adjustment Mechanism*, Docket No. UE 390, Order No. 21-379, page 1.
[4] Exhibit PAC/200, Owen/4 - 8.

Q. Regarding evaluation of the Company's management of established CSAs, does PacifiCorp discuss the CSAs of other coal plants, where the CSA was not superseded by a new CSA?

A. Yes. The Company briefly discusses aspects of and outcomes from the CSAs for the Wyodak, Dave Johnston, Hunter, Huntington, Craig, Hayden, and Colstrip coal-fueled plants. I review these discussions as Issue 2.

Q. Do these seven coal-fueled plants, plus Naughton, represent PacifiCorp's entire fleet of coal-fueled plants?

A. No. PacifiCorp has nine operating coal-fueled plants, and the one not identified above is Jim Bridger.[5]

Q. Did the Commission require action by PacifiCorp regarding the Jim Bridger plant's materials and supplies costs in its 2022 TAM Order?

A. Yes. The Commission required PacifiCorp to include a discussion of these costs in its updated Jim Bridger Long Term Fuel Plan.[6] The Company instead addressed it in its Direct Testimony. I address this as Issue 3.

Q. Did the Commission require action by PacifiCorp regarding Jim Bridger in its 2022 TAM Order?

A. Yes. The Commission required the Company to update and file the Jim Bridger Long Term Fuel Plan document in the 2023 TAM.[7] I discuss the Jim Bridger long-term fuel plan as Issue 4.

---

[5] *See*; e.g., slide 4 ("Coal Plant Status") of my presentation regarding an IE for UM 2183 at the May 5, 2022 Public Meeting, located here (accessed on May 8, 2022).
[6] Order 21-379, page 15
[7] Order 21-379, page 14.

Q. What did the 2022 TAM Order include regarding the Huntington plant?

A. The Commission, in Order No. 21-379, indicated that "PacifiCorp needs to present analysis on the costs and benefits of pursuing Huntington's **[Begin Confidential]** [redacted] **[End Confidential]**.[8]" It included that "[i]f PacifiCorp does not thoroughly explore the costs and benefits of contract termination or renegotiation [of the plant's CSA, the Commission] would be willing to entertain an argument for a disallowance."[9] I examine the evidence provided by PacifiCorp as Issue 5.

Q. Did the Commission, in Order No. 21-379 in the 2022 TAM, require PacifiCorp to complete a follow-up economic cycling study?

A. Yes. The direction provided by the Commission included that the follow-up study should address "whether economic cycling of units, with reliability considerations factored in, creates savings for customers."[10] I discuss this study as Issue 6.

Q. Did the Commission, in Order No. 21-379 in the 2022 TAM, require PacifiCorp to report specific data regarding coal prices and the modeling of minimum take levels?

A. Yes. The Commission required that PacifiCorp provide, in future TAM filings, the initial incremental price for each coal plant, the final dispatch tier price, and the magnitude of the difference for the TAM year and three preceding years. I discuss this reporting as Issue 7.

[8] Id., page 23.
[9] Id., page 23.
[10] Id., page 9.

ISSUE 1. NAUGHTON NEW CSA

Q. Did PacifiCorp provide testimony supporting the new CSA for the coal-fired portion of the Naughton plant?

A. Yes.[11] Additionally, and associated with the Company's Direct Testimony, highly confidential Exhibit PAC/201 describes the new CSA, provides specific information regarding key provisions, and includes a coal procurement valuation for the Naughton plant's new CSA.

Q. What is a "coal plant procurement valuation?"

A. PacifiCorp uses certain inputs to and results of its 2021 IRP modeling, including the Medium-Medium, High-High, and Low-None price-policy scenarios for, respectively, natural gas prices and greenhouse gas emissions policy, to perform economic analysis of the new CSA.

Q. Is the Naughton plant nearing its retirement date?

A. Yes. PacifiCorp's 2021 IRP identified December 31, 2025, as the end of useful life for Units 1 and 2, which are the two remaining coal-fired units.[12] Naughton Units 1 and 2 are also subject to environmental compliance obligations under the federal coal combustion residuals (CCR) rule.[13]

Q. Has the CCR rule been finalized?

[11] Exhibit PAC/200, Owen/4-8.
[12] Id., page 5.
[13] Id.

A. Not according to PacifiCorp. The Company states that, if the rule is finalized, it will not allow Units 1 and 2 to operate on coal beyond their current remaining useful life.[14]

Q. What is the term of the new CSA for Naughton?

A. The term of the new CSA is **[Begin Confidential]** [redacted] **[End Confidential]**.[15]

Q. Did the Commission provide guidelines for the types of analyses that should accompany a new CSA for a plant nearing retirement?

A. No. The Commission instead provided general expectations, including:

> [W]e expect PacifiCorp to explain how it incorporates its IRP planning into its TAM-reviewed fuel contracts, or its management of those contracts. When we review a CSA, we will need to understand how PacifiCorp considered future costs in multiyear contracts, especially given that its plans for operating a plant generally would be expected to show declining production before retirement. PacifiCorp will need to explain how it is allowing for an orderly sequence towards retirement and ensuring flexibility for reduced capacity factors and consumption of the coal pile, and how it will manage the contract in the event that circumstances change from those expected when it was signed. We do not require an extra plan or report, and expect the parties will raise different concerns with different units in each TAM, but ultimately, we expect that PacifiCorp will explain its general plan and why it is reasonable for customers.[16]

Q. Did PacifiCorp explain the incorporation of its IRP planning in reviewing the new Naughton CSA?

A. Yes. The Company's highly confidential Exhibit PAC/201 states that **[Begin Highly Confidential]** [redacted]

[14] Id.
[15] Id.
[16] Order No. 21-379, page 7.

[redacted] **[End Highly Confidential]**[17]

Q. Did PacifiCorp explain how it considered future costs in the multiyear contract?

A. Yes. The Company's highly confidential Exhibit PAC/201 states that **[Begin Highly Confidential]** [redacted][18] [redacted] **[End Highly Confidential]**[19] I also note PacifiCorp's statement that the cost per ton of coal for the Naughton plant was **[Begin Confidential]** [redacted] **[End Confidential]** in the 2022 TAM.[20]

Q. Are you concerned with this threshold regarding fixed prices?

[17] Highly confidential Exhibit PAC/201, Owen/1.
[18] Highly confidential Exhibit PAC/201, Owen/2.
[19] Table 1 at highly confidential Exhibit PAC/201, Owen/2.
[20] PAC/200, Owen/19.

A. Not at this time. While headline consumer inflation (CPI) has been accelerating on a year-over-year basis since May 2020,[21] with an increase of 8.5 percent for March 2022, versus a year earlier, it is not clear from PacifiCorp's testimony or exhibits what measure(s) of inflation is being used or how, and I have submitted data requests to ascertain this.

Q. Are there economical alternative supply sources?

A. Probably not. **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** [22]

Q. Does PacifiCorp forecast declining production from Naughton Units 1 and 2?

A. **[Begin Confidential]** [redacted] **[End Confidential]**

Q. Did PacifiCorp provide a "detailed explanation of how economic cycling was considered"[23] for the new CSA?

A. The Company noted that, **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]**[24]

---

[21] See the BLS chart here (accessed on May 8, 2022).
[22] Highly confidential Exhibit PAC/201, Owen/1.
[23] Order No. 21-379, page 6.
[24] Highly confidential Exhibit PAC/201, Owen/6.

Q. What are your thoughts regarding the [Begin Confidential] [redacted] [End Confidential] level of price per ton in 2023 under the new CSA than the price per ton in 2022?

A. The total delivered price per ton at Naughton **[Begin Confidential]** [redacted] **[End Confidential]** in the 2022 TAM to **[Begin Confidential]** [redacted] **[End Confidential]** in the 2023 TAM, **[Begin Confidential]** [redacted] **[End Confidential]**[25] I acknowledge that this rate of **[Begin Confidential]** [redacted] **[End Confidential]** depends on the combination of coal purchased under the new CSA versus the old CSA, with the later manifested by the coal pile (and the timing of its reduction amounts—see below).

Q. Does PacifiCorp provide support for a [Begin Confidential] higher [End Confidential] price per ton under the new CSA?

A. Yes. Confidential Table 2 at Exhibit PAC/200, Owen/12 shows that, **[Begin Confidential]** [redacted] **[End Confidential]**. Additionally, and shown in confidential Table 2 for PacifiCorp's coal-fueled plants in the aggregate, the volume of coal purchased is expected to **[Begin Confidential]** [redacted] **[End Confidential]** in 2023 versus 2022.

PacifiCorp includes an unlabeled table at Exhibit/200, Owen/3 showing the absolute and percent **[Begin Confidential]** [redacted] **[End Confidential]** in

[25] Confidential Exhibit PAC/200, Owen/19.

price per ton for 2023 in the 2022 TAM versus the 2023 TAM for Powder River Basin (PRB) coal (at two levels of heat content), Utah coal, and Colorado/Yampa coal, with an unweighted average price increase between the two TAM filings for these sources of **[Begin Confidential]** [redacted] **[End Confidential]**.

Anecdotally, PacifiCorp states that spot prices for 8,800 British thermal units per pound (Btu/lb) coal produced in the Powder River Basin "more than doubled between September and November of 2021."[26]

The Company asserts that "[r]ising general inflation, the reduced contractual commitment and added coal supply flexibility are the primary drivers increasing the contract price."[27]

Q. Does PacifiCorp explain how it is allowing for an orderly sequence towards the retirement of Naughton Units 1 and 2 and ensuring flexibility for reduced capacity factors and consumption of the coal pile, and how it will manage the contract if circumstances change from those expected when the CSA was signed?

A. It does—for the most part. With respect to the coal pile and the escalation in price per ton, I provide, in highly confidential Exhibit Staff/602, an alternative pattern of 2022 – 2025 purchases and coal pile reduction over the 2023 – 2025 timeframe, which reduces coal costs by approximately $0.4 million on a net

[26] Exhibit PAC/200, Owen/3
[27] Id., page 19.

present value basis from that in the analysis provided by PacifiCorp, while maintaining a purchase level that is within the contracted annual limits.

Q. What do you recommend regarding the new CSA for the Naughton plant?

A. I recommend a reduction in allowed expense of $463 thousand for the 2023 TAM, based on my analysis of an alternative annual pattern in coal purchases and pile depletion that is within the maximum/minimum range for all years, and results in a $463 thousand lower present value of purchases when valued as of January 1, 2023. See highly confidential Exhibit Staff/602.

Q. Is your investigation of the Naughton CSA complete.

A. Not yet. Additionally, I will evaluate testimony provided by other Parties in this proceeding before determining whether additional disallowances are appropriate.

ISSUE 2. THIRD-PARTY COAL CONTRACTS

Q. Does PacifiCorp discuss these in a separate section of the Company's Direct Testimony?

A. Yes; beginning at Exhibit PAC/200, Owen/19. I discuss CSAs and coal supply issues for the Naughton, Jim Bridger, and Huntington plants elsewhere in testimony. This section of PacifiCorp's testimony, along with information in the unlabeled table at PAC/200, Owen/11 and Confidential Table 2,[28] contains the primary information and discussion for the remaining six coal plants: Colstrip, Craig, Dave Johnston, Hayden, Hunter, and Wyodak.

Q. What information is included for each of these six plants?

A. The discussion for each includes the 2022 TAM coal price per ton, the 2023 TAM price per ton, and the dollar amount of change from the 2022 TAM to the 2023 TAM.

Q. What additional information does PacifiCorp provide regarding individual plants?

A. This varies by plant, as highlighted below.

<u>Colstrip</u>[29]

- Cost increase is primarily due to an increase in contract indices and is partially offset by a higher volume of tier 2 coal being purchased.

---

[28] Exhibit PAC/200, Owen/12.
[29] Exhibit PAC/200, Owen/23.

Craig[30]

- PacifiCorp is a co-owner of the Trapper mine, which is an affiliate captive mine owned by three of the five Craig plant owners.
- The decrease in price per ton is primarily due to lower mining costs resulting from a change in mining method.
- Deliveries will decrease **[Begin Confidential]** [redacted] **[End Confidential]** in the 2023 TAM from the 2022 TAM.

Dave Johnston[31]

- The increase in delivered coal costs result from an increase in coal prices and an increase in rail cost (due to increases in rail indices and diesel fuel costs).
- PacifiCorp will rely upon an RFP to fill an open position, currently designating the source as unspecified PRB coal.
- The average 2023 forward price for PRB 8,400 Btu coal is being used to calculate costs for the 2023 TAM.
- The increase in price over that used for the open position in the 2022 TAM reflects the impact of increased coal market pricing.

Hayden[32]

- **[Begin Confidential]** [redacted]

[30] Exhibit PAC/200, Owen/22.
[31] Exhibit PAC/200, Owen/20.
[32] Exhibit PAC/200, Owen/22.

[redacted] **[End Confidential]**

Hunter[33]

- PacifiCorp separates the coal prices and cost changes between the two suppliers as well as providing totals.
- Increased coal prices result from annual price increases in the respective CSAs and increasing transportation indices.

Wyodak[34]

- Current CSA will end December 31, 2022, and a new CSA negotiated during 2022, with new prices included in the 2023 TAM update, if possible.

Q. Does the information PacifiCorp provided in testimony, associated with the third-party contracts for the five coal-fueled plants not having an affiliate mine,[35] fulfill the Commission's direction that the Company provide information necessary to facilitate Parties' evaluation of the Company's management of established CSAs?[36]

A. Yes; in part. First, the compilation of changes in prices, volumes, costs, and the percent changes thereto between TAM filings into one confidential table would

[33] Exhibit PAC/200, Owen/20-21.
[34] Exhibit PAC/200, Owen/19-20.
[35] Of the six coal-fueled plants discussed in this section, Craig is supplied from an affiliate mine.
[36] *See,* e.g., page 1 of Order No. 21-379 in Docket No. UE 390.

be useful. Secondly, I recommend PacifiCorp be directed to implement the additional changes below for this table in future TAM filings.

1. For those plants supplied by a third party, list the term of the CSA valid for the TAM proceeding at hand.
2. For those coal-fueled plants having a "common closure" date for coal operations that is within the term of the CSA applicable to the TAM proceeding at hand, provide an analysis of the Company's plan to optimize the use of the coal pile over the time remaining until closure. Information regarding minimums, maximums, prices, and annual coal pile inventory should be included in the table.

ISSUE 3. JIM BRIDGER MATERIALS AND SUPPLIES COSTS

Q. Did the Commission provide direction to PacifiCorp regarding the update to the Jim Bridger Long Term Fuel Plan to be filed in the proceeding at hand?

A. Yes. The Commission made several points about the updated Plan:

- It should explicitly reflect the changing future of Jim Bridger;
- PacifiCorp should look at scenarios that may involve even significant change in management of the resources, such as, for example, the consequences of fueling Jim Bridger solely from Bridger Coal Company (BCC) or solely from Black Butte;
- The Commission had concerns regarding a pre-set BCC production level or Black Butte delivery that could impair portfolio changes already promised;
- PacifiCorp should ensure the updated Plan allows Jim Bridger to decrease output as new generation comes online;
- It should include an average cost analysis;
- It should include a discussion of BCC materials and supplies expense; and
- It should provide the opportunity for parties to review components of BCC coal costs as well as the whole of BCC costs.

Q. How did PacifiCorp respond in its 2023 TAM filing to the direction provided by the Commission with respect to an updated Plan?

A. The Company addressed the "discussion of [Bridger Coal Company's Materials and Supply] costs" in Exhibit PAC/200, with the updated Plan to ostensibly cover any remaining requirements filed on April 15, 2022, in Docket No. UE 400.[37]

Q. What did PacifiCorp include in Exhibit PAC/200 regarding materials and supplies in Jim Bridger's coal costs?

A. The Company included a two Question and Answer discussion approximately one page in length. It also included confidential Exhibit PAC/202.[38]

Q. Please describe the discussion in Exhibit PAC/200.

A. PacifiCorp's discussion included a paragraph describing why the Company included "a discussion of coal and reclamation costs…based on production and cost information assumed in the 2023 TAM," referencing confidential Exhibit PAC/202. It listed information available in Exhibit PAC/202, including tons of coal delivered, cubic yards moved (production and final reclamation), and the following costs by component: coal costs, final reclamation costs, total costs, and operating costs.[39] I include PacifiCorp's discussion of confidential Exhibit PAC/202 below:

> The "Adjusted Dollars" total in the "Coal Cost" column is the amount included in the 2023 TAM and represents estimated costs incurred to produce and deliver coal to the Jim Bridger plant from Bridger Coal Company (BCC). Final reclamation costs represent costs to complete planned final reclamation activities. The column labeled "Total Costs" is the sum of projected costs incurred to complete coal production and final reclamation activities. The column labeled "Operating Cost" combines

[37] Exhibit PAC/100, Wilding/41. See also Order No. 22-065 in Docket No. UE 400, which amends Order No. 21-379 in Docket No. UE 390 such that the filing date of the updated Plan is "no later than April 15, 2023" [*sic*] and repeats certain requirements and other direction the Commission provided to PacifiCorp in Order No. 22-065.
[38] Costs in confidential Exhibit PAC/202 are on a PacifiCorp share of ownership basis.
[39] PAC/200, Owen/10-11.

coal and reclamation costs by component and aligns with BCC's reporting structure.[40]

Q. Did PacifiCorp discuss BCC's materials and supplies costs in its Direct Testimony?

A. Yes, and I include the "Q&A" representing this discussion below.

> **Q. Does this exhibit show that the material and supply costs included in the TAM are appropriate?**
>
> A. Yes. Confidential Exhibit PAC/202 identifies costs incurred to produce and deliver coal, as well as costs to complete final reclamation activities. This is consistent with previous testimony filed in the 2022 TAM and demonstrates that when evaluating the prudence of operating costs incurred at BCC, both coal production and final reclamation activities should be considered.[41]

Q. Does confidential Exhibit PAC/202 include the information listed by PacifiCorp, as detailed above?

A. Yes, including component costs.

Q. Does confidential Exhibit PAC/202 include the component costs for BCC's materials and supplies?

A. Yes, and these are identified as costs for **[Begin Confidential]** [redacted]

[40] PAC/200, Owen/10.
[41] Id. Included footnote omitted here.

[redacted] **[End Confidential]**

Q. Does confidential Exhibit PAC/202 demonstrate "that…both coal production and final reclamation activities should be considered" when evaluating the prudence of operating costs incurred at BCC, as asserted in PacifiCorp's testimony?

A. No. It does not.

Q. Does PacifiCorp's testimony in Exhibit PAC/200 and confidential Exhibit PAC/202 include a discussion of BCC materials and supplies expense?

A. Yes, as I fully replicated above.

Q. Does PacifiCorp's testimony in Exhibit PAC/200 and confidential Exhibit PAC/202 provide the opportunity for parties to review components of BCC coal costs as well as the whole of BCC costs?

A. Yes.

Q. Do you believe the components of materials and supplies listed above are appropriate for coal cost?

A. Yes.

Q. Do you believe the components of materials and supplies listed above are appropriate for final reclamation cost?

A. I conclude it is reasonable that such expenses could be actual components of materials and supplies associated with final reclamation activities.

Q. Have you, in the context of this proceeding, performed an investigation into or audit of component materials and supplies amounts included in confidential Exhibit PAC/202?

A. No; I have not.

ISSUE 4. JIM BRIDGER LONG-TERM FUEL PLAN

Q. When did PacifiCorp file its Jim Bridger Long Term Fuel Plan?

A. The Company filed the highly confidential Jim Bridger Long Term Fuel Plan ("Plan") on April 15, 2022, in Docket No. UE 400.

Q. Why was it not filed concurrently with the 2023 TAM filing?

A. The Company was granted its motion for an extension of the required filing date to April 15, 2022. The motion cited significant uncertainties regarding multiple processes, involving U.S. EPA's regional haze obligations; revised dates for Idaho Power Company's exit from Jim Bridger; PacifiCorp's commitment to evaluate carbon capture, utilization and storage (CCUS) at the plant; and EPA's proposal to establish new nitrogen oxides (NOx) emissions budgets under Ozone National Ambient Air Quality Standards (Ozone Transport Rule) in states including Utah and Wyoming.[42]

Q. What did the Commission conclude, In Order No. 22-065 in Docket No. UE 390, regarding PacifiCorp's reasoning behind the request for an extension?

A. The Commission stated that it was not persuaded that uncertainty prevented the Company from filing a long-term fuel plan consistent with Order No. 21-379.[43]

Q. Did the Commission provide additional direction or clarify existing direction regarding the objective of the Plan update?

[42] Pages 3-4 of Motion filed February 11, 2022, in Docket No. UE 390.
[43] Page 4 of Order No. 22-065 in Docket No. UE 390.

A. Yes. The Commission stated that it had in Order No. 21-379 "directed PacifiCorp to examine scenarios that could present a significant change in the management of its resources and to ensure that its plan allowed the facility to decrease output as new generation comes online."[44] Additionally, the Commission stated that "[t]he purpose of the updated Plan…is to provide an evaluation and analysis of those different scenarios and to review how PacifiCorp is taking these analyses into consideration as it makes decisions surrounding fuel supply for the Jim Bridger facility," and the analyses provided in the updated Plan "should contemplate multiple plausible scenarios…"[45] The Commission stated that it "is important that PacifiCorp demonstrate that it is conducting the appropriate analysis before it makes potentially costly decisions for ratepayers."[46]

Q. Did PacifiCorp note the expectation for the Plan to be filed by April 15, 2022?

A. **[Begin Confidential]** [redacted]

[redacted][47]

[44] Id., page 4, *citing* Order No. 21-379, page 14.
[45] Id., page 5.
[46] Id.
[47] Highly confidential Jim Bridger Long Term Fuel Plan (Plan), page 4, *citing* Order No. 22-065, page 5, in Docket No. UE 390.

[End Confidential]

Q. When are Units 1 and 2 planned to stop consuming coal?

A. This is planned for year-end 2023.

Q. When are Units 3 and 4 planned to stop consuming coal?

A. This is planned for year-end 2037.

Q. When does the existing Bridger mine CSA end?

A. The current Bridger mine CSA ends in **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]**.[48]

Q. For purposes of scenario development, how many discrete periods did PacifiCorp develop?

A. **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]**[49]

Q. For purposes of scenario development, how many potential sources of coal did PacifiCorp use?

A. **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]**[50]

Q. How many alternative scenarios of Jim Bridger coal fueling did PacifiCorp examine in the Plan?

---

[48] Plan, page 13.
[49] Id.
[50] Id., page 7.

A. **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** Table 1 below includes average annual tonnage of coal.

Table 1: Jim Bridger Average Annual Tons of Delivered Coal by Source – PacifiCorp Basis (Estimated Millions of Tons)[51]

[Begin Highly Confidential]

[redacted]

[End Highly Confidential]

[51] Based on information in pages 13 – 16 of the highly confidential Plan.

Q. How did PacifiCorp evaluate the costs associated with these [Begin Highly Confidential] [redacted] **[End Highly Confidential]?**

A. The Company's cost analysis used the **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]**[52]

Q. What Scenario evaluated as the least-cost, under the assumption and methodology used by PacifiCorp in its analysis?

A. **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]**[53]

---

[52] Id., **[Begin Highly Confidential]** page 17. **[End Highly Confidential]**
[53] See **[Begin Highly Confidential]** Table 2 on page 17 **[End Highly Confidential]** of the highly confidential Plan update.

Q. Oregon will exit PacifiCorp's coal-fired plants by no later than year-end 2030. Did PacifiCorp provide analysis predicated on this legal requirement?

A. **[Begin Highly Confidential]** [redacted]

Table 2: Scenarios PVRR(d) ($Millions)

[redacted]

[End Highly Confidential]

Q. The common "metric" used by the Commission regarding alternative resources in IRP is "least cost – least risk." Did PacifiCorp perform any risk analysis associated with evaluation of the five scenarios?

A. **[Begin Highly Confidential]** [redacted]

[redacted] **[End Highly Confidential]**

Q. Regarding fuel procurement for Jim Bridger, what PacifiCorp set of decisions do you understand to be currently operatable?

A. I understand PacifiCorp is **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]**

Q. In your opinion, does the Plan examine scenarios that could present a significant change in the management of its resources and scenarios that allowed the facility to decrease output?

A. I believes it does. Coal deliveries **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]**

[54] See Plan, Table 4 on page 18 and Table 5 on page 19.

Q. In your opinion, does the Plan "contemplate multiple plausible scenarios?"

A. I believe it does, **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]**

Q. In your opinion, does the Plan "demonstrate that PacifiCorp is conducting the appropriate analysis before it makes potentially costly decisions for ratepayers?"

A. I believe the Plan fell short on this measure, and suggests PacifiCorp include certain conditional analyses in future Plan updates.

Q. Please provide an example of what you are calling "conditional analyses."

A. A simple example would be the inclusion of what the Company's costs would be under alternative terms and conditions of a set of future CSAs – **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]**—with respect to the plant's closure. This could address the question of the Company's costs under a given set of future CSAs if the plant closed in 2027, 2030, and 2034, instead of 2037 and for alternative sets of future CSAs.

ISSUE 5. HUNTINGTON CSA

Q. What is the issue with the Huntington CSA?

A. The Commission found, in PacifiCorp's last TAM proceeding,[55] that "a portion of the Huntington minimum take delivery amount is not economic in today's energy market…,"[56] which it characterized as one "shaped by new environmental laws."[57] The Commission required PacifiCorp to present analysis on the costs and benefits of pursuing Huntington's **[Begin Confidential]** [redacted] **[End Confidential]** and, if the Company "did not thoroughly explore the costs and benefits of contract termination or renegotiation, [the Commission] would be willing to entertain an argument for a disallowance."[58]

Q. How did PacifiCorp view the energy market as of the 2022 TAM vis-à-vis the [BEGIN CONFIDENTIAL] [redacted] **[END CONFIDENTIAL]?**

A. The Company agreed "to continue to monitor market and regulatory conditions to assess whether there is an opportunity to invoke the termination clause," but did not "find those conditions exist at [that] time."[59]

Q. Does PacifiCorp's testimony in this proceeding discuss this issue?

A. Yes. The Company's testimony includes a one sentence "brief history" of the Huntington CSA, noting that it will end December 31, 2029, and asserts it "is

[55] This was Docket No. UE 390, PacifiCorp's 2022 TAM proceeding.
[56] Order No. 21-379, page 22.
[57] Id.
[58] Id., page 23.
[59] Id., page 21.

working with Energy Ventures Analysis (EVA) to produce a thorough analysis on [the costs and benefits of contract termination or renegotiation], and anticipates providing this analysis to parties by April 15," following the March 1, 2022, filing of PacifiCorp's Direct Testimony.[60]

Q. Has PacifiCorp filed such an analysis?

A. Yes. The Company filed its highly confidential **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** (Huntington Analysis) in this docket on April 28, 2022.

Q. What is the [Begin Highly Confidential] [redacted] **[End Highly Confidential]?**

A. **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]**[61]

Q. When was the CSA negotiated?

A. PacifiCorp signed the **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]**

[60] Exhibit PAC/200, Owen/8-9.
[61] Huntington Analysis, page 1.

Q. Does the Huntington Analysis discuss how the [Begin Highly Confidential] [redacted] **[End Highly Confidential]?**

A. **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]**[62]

Q. Does EVA, in the Huntington Analysis, take a position as to whether PacifiCorp has the right to exercise the clause under the CSA?

A. **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]**[63]

Q. Does PacifiCorp, in its Direct Testimony, take a position as to whether the Company has the right to exercise the clause under the CSA?

A. **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]**[64]

Q. What did CUB, in the UE 390 2022 TAM proceeding, recommend?

A. CUB recommended that PacifiCorp conduct an analysis to "determine whether the Huntington CSA is leading to uneconomic dispatch of the plant, whether it is due to new environmental laws and regulations, and whether it is in PacifiCorp's customers' interest to invoke the contract termination provisions by weighing the value of termination against any risks."[65]

Q. What key assumptions did EVA make in its analysis of [Begin Highly Confidential] [redacted] **[End Highly Confidential] of the Huntington CSA?**

---

[62] Id., pages 2-3.
[63] Id., pages 1-2.
[64] Exhibit PAC/200, Owen/8-9.
[65] Order No. 21-379, page 21, *citing* CUB's Reply Brief at 13.

A. EVA made several key assumptions in its analysis. These include:

1. **[Begin Highly Confidential]** [redacted]

2. [redacted]

3. [redacted]

[End Highly Confidential][66]

Q. What were EVA's conclusions in the Huntington Analysis?

A. I repeat below EVA's conclusions should PacifiCorp exercise the **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** clause of the Huntington CSA:

[66] Huntington Analysis, page 8.

[Begin Highly Confidential]

[redacted]

[End Highly Confidential]

Q. Please provide your assessment of the Huntington Analysis.

A. If PacifiCorp's objective for the Huntington Analysis was to "thoroughly explore the costs and benefits of contract termination or renegotiation,"[67] this objective was not realized. For starters, I take issue with the assumption of the singular exercise date of January 1, 2022. While I concur the Huntington plant's **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** clause has value, the Huntington Analysis should have included analysis demonstrating this. An example might be in the context of a January 1, 2028, exercise date; i.e., with **[Begin Highly Confidential]** [redacted] **[End Highly Confidential]** remaining on the CSA's term. Another area I conclude was less than thorough was in the consideration of joint coal supply between the

[67] Page 23 of Order No. 21-379 in Docket No. UE 390.

Huntington and Hunter plants under the Huntington CSA, the Hunter CSAs, or a combination of each plant's CSAs. I note that, while trucking coal is presumed to be comparatively inefficient, the two plants are approximately 21 miles apart, most of which distance is over Utah state highways 31 and 10.[68] While it is clear to me that the economic feasibility of sourcing Hunter coal under the Huntington CSA depends much on characteristics of the Hunter CSA(s), and potentially the costs of contract trucking, there is no mention of any analysis to optimize the cost of coal supply between the two plants, let alone any reasons that doing so at any point time between now and year-end 2029 is impossible.

The Huntington Analysis does not discuss the reverse situation from the scenario developed in the Huntington Analysis; i.e., the supply of Huntington under the Hunter CSAs following the assumed cancellation of the Huntington CSA by the seller as of year-end 2023, in which Huntington is supplied—in whole or in part—by coal procured under the Hunter CSAs going forward. I note the assertion in the Huntington Analysis that PacifiCorp can supply all of the coal for Hunter purchased under two existing [Hunter] contracts at prices below the Tier 1 price of the [Hunter] CSA.[69]

I point to the Commission's having taken notice of PacifiCorp's statement regarding Aurora's capability:

> PacifiCorp has indicated that its Aurora model may be capable of considering reliability while identifying which coal units to cycle, which

[68] Google Maps.
[69] Huntington Analysis, page 8.

> would remedy Staff's main complaint with the cycling study in this [2022] Tam.[70]

Q. Did PacifiCorp clarify, in its follow-up study, that Aurora was NOT capable of this specific analysis?

A. No; it did not.

Q. What do you recommend regarding the Huntington Analysis?

A. I conclude the Huntington Analysis is not a thorough explanation of the costs and benefits of contract termination or renegotiation. As noted above, the Commission's order to perform the analysis was based, at least in part, on CUB's request for such an analysis to determine whether the Huntington CSA is results in uneconomic dispatch of the plant.[71] The analysis provided by PacifiCorp does not allow the Commission to resolve this question. Accordingly, in absence of this showing, I recommend the Commission reduce PacifiCorp's 2023 TAM expense by $50 thousand.

Q. What does the $50 thousand represent?

A. I appreciate the high degree of arbitrariness in its recommendation of a $50 thousand reduction to the 2023 TAM net power costs (NPC). I believe incremental efficiencies with regard to NPC may be possible and, absent a more thorough analysis by PacifiCorp conclusively demonstrating this, $50 thousand represents approximately 0.003 percent[72] of PacifiCorp's proposed $1.684 billion[73] NPC for 2023. One way of viewing the $50 thousand

[70] Order No. 21-379, page 10.
[71] Order No. 21-379, page 21.
[72] 0.003 percent is three one-thousands of one percent.
[73] Exhibit PAC/100, Wilding/3.

is that it would not take a great deal of increased efficiency, on a forecasted basis, to achieve a $50 thousand reduction in NPC.

ISSUE 6. ECONOMIC CYCLING FOLLOW-UP STUDY

Q. Did the Commission, in Order No. 21-379 in the 2022 TAM, require PacifiCorp to complete a follow-up economic cycling study?

A. Yes. The direction provided by the Commission included that PacifiCorp "complete a follow-up economic cycling study as Staff requests" and that the follow-up study should address "whether economic cycling of units, with reliability considerations factored in, creates savings for customers."[74]

Q. What did Staff request?

A. Staff's thinking on what should be included in a follow-up economic cycling study had two primary aspects. First, that the modeling in the original study, which resulted in a large volume of "emergency purchases," could be improved to show economic cycling in a way that meets the requirements of a reliable generation plant. Second, Staff suggested PacifiCorp look for available short-term capacity contracts or other resources that can provide shoulder season capacity at a lower cost than coal and reduce the number of coal units that are allowed to cycle off at a given time. Alternatively, Staff suggested utilization of "a new model that is able to consider reliability in its economic cycling decisions."[75]

Q. Does PacifiCorp's use of Aurora for modeling power costs in the 2023 TAM represent "a new model able to consider reliability in its economic cycling decisions" in the sense meant by Staff?

[74] Order No. 21-379, pages 9-10.
[75] Id., page 8.

A. Perhaps, and I have issued data requests to PacifiCorp regarding this point.

Q. What are “emergency purchases” in the context of modeling PacifiCorp’s power costs using Aurora?

A. PacifiCorp explains that emergency purchases are “simply a modeling construct that allows Aurora to solve in the absence of economically superior alternatives, or in instances where the system resources are insufficient to balance generation and load.”[76] Emergency purchases “help the model meet its reliability target to ensure there is no unserved load”[77]

Q. How did PacifiCorp use the binary “must run” setting in the 2022 TAM power cost modeling?

A. The Company states that it removed the “must run” setting as part of the transition to Aurora and asserts that the removal “essentially enables the model to “economically cycle” the coal plants throughout the year, subject only to the operational constraints that the plants face in reality.”[78]

Q. Did PacifiCorp remove the “must run” setting for all power cost modeling in the 2023 TAM?

A. Apparently the Company did not remove the “must run” setting for all power cost modeling in the 2023 TAM, as it states the terms of the 2021 TAM settlement included that the Company provide “NPC based on an Aurora run that removes the “must run” setting.[79]

---

[76] Exhibit PAC/100, Wilding/44.
[77] Id.
[78] Exhibit PAC/100, Wilding/42.
[79] Id.

Q. What does PacifiCorp say is the result of turning off the "must run" setting?

A. The Company states that turning the "must run" setting off makes certain operational constraints, such as minimum up and down times and start-up costs, become binding and that the added complexity of the optimization results in "the model run time increasing from 90 minutes (must run setting turned on) to seven hours per run with it turned off."[80]

Q. Does PacifiCorp claim that modeling power costs without the "must run" setting departs from actual operations?

A. Yes. The Company assets that Aurora's "must run" settings approximate actual operations in two ways. Using the setting avoids additional start-up costs that would be incurred if the units were entirely shutdown and that "entirely shutting down a coal unit creates reliability risks because of the start time necessary to bring a coal unit back online once it has been entirely shut down."[81] PacifiCorp additionally states that, for these reasons, in actual operations, the Company will typically cycle a coal unit to its minimum when needed but will not entirely shut it down. The Company asserts that removing the "must run" setting departs from actual operations and makes Aurora's optimized unit dispatch unrealistic.[82]

Q. What is your perspective on the Company's reasoning on this point?

---

[80] Id., page 43.
[81] Id.
[82] Id., pages 43-44.

A. I find PacifiCorp's reasoning here to be "off the mark." The purpose of economic cycling modeling is to ascertain the circumstances, if any, under which reduction in coal unit dispatch can result in reduced power costs without producing any reliability issues. In other words, use the results of such modeling to better inform actual operations, which may change actual operations so that they become more like the modeled system.

Q. Did PacifiCorp provide an economic cycling study with its 2023 TAM filing?

A. Yes.

Q. What did PacifiCorp say was the result of its study?

A. That in "every coal-cycling that PacifiCorp studied, NPC increased, and reliability decreased."

Q. How many alternatives or scenarios did the Company examine?

A. Three, with comparisons to a base case (S01) in which the "must run" setting was turned on.

Q. How did the four scenarios differ?

A. One scenario (S02) incorporated a minimum up and down time set to 48 hours. Another (S04) incorporated a minimum up and down time set to 168 hours. The third scenario (S03) only allowed coal units to cycle in Spring and in Fall; i.e., in shoulder seasons.

Q. What were PacifiCorp's quantitative results of its study?

A. I include the change in net power costs from the base case and the necessary level of emergency purchases for each scenario with the "must run" setting off in Table 3 below.

Table 3: Primary Results of PacifiCorp's Follow-up Economic Cycling Study with "Must Run" Setting "Off"

Scenario	Incremental NPC ($Millions)[83]	Emergency Purchases (GWh)[84]
S02	$5	23
S03	$6	197
S04	$679	5,430

Q. Did PacifiCorp attempt to locate available short-term capacity contracts or other resources that can provide shoulder season capacity at a lower cost than coal, as Staff suggested, and incorporate such resources into the Company's follow-up Economic Cycling Study?

A. No. Alternatively, if PacifiCorp did attempt to locate such resources, the Company neither described such a search nor its results in its Direct Testimony.

Q. How many coal-fired plants and units does PacifiCorp operate?

[83] Values taken from Table 4 at Exhibit PAC/100, Wilding/46.
[84] Values taken from Tables 5, 6, and 7 at, respectively Exhibit PAC/100, Wilding/47, Wilding/50, and Wilding/52.

A. I understand the Company currently operates six plants having one or more coal-fired units. These are Dave Johnston, Hunter, Huntington, Jim Bridger, Naughton, and Wyodak.

Q. How many of these six plants have multiple coal-fired units?

A. I understand that five plants operated by PacifiCorp have multiple coal-fired units, including Dave Johnston (four units), Hunter (three units), Huntington (two units), Jim Bridger (currently four units), and Naughton (currently two units).

Q. Of the six coal-fired plants PacifiCorp operates, how many have shared ownership?

A. I understand three of them have shared ownership: Hunter (Unit 2 is co-owned), Jim Bridger, and Wyodak. This implies that, of the coal-fired plants operated by PacifiCorp, it wholly owns three: Dave Johnston, Huntington, and Naughton. I note that each of these plants has multiple units.

Q. For its follow-up Study, how did PacifiCorp model the coal plants where it is not the only owner as compared to those where it is the sole owner?

A. The Company states that Scenario S02 was run with the minimum up time for all PacifiCorp operated coal resources set to 48 hours.[85] This would include some plants (or some units within plants) that are co-owned.

[85] Exhibit PAC/100, Wilding/46.

The Company states that Scenario S03 had the minimum up and down time for all owned coal resources set to 168 hours, and the co-owned resources were set to "Must Run."[86]

The Company states that Scenario S04 had the minimum up and down time set to 168 hours for all coal resources.[87]

Q. Do you see an additional modeling approach that is more consistent with Staff's suggestion that PacifiCorp reduce the number of coal units that are allowed to cycle off at a given time?

A. Yes. While I appreciate that the Company ran three scenarios other than the Base Case, setting the "Must Run" control off for the least efficient unit in the multi-unit plants, one-by-one in the shoulder seasons and starting with the least efficient unit of these plants, or perhaps only working with the least efficient unit in the multi-unit plants it wholly owns, might produce insights that positively influence actual operations.

Q. What do you recommend?

A. As PacifiCorp provides no evidence of the Company's attempt to locate available short-term capacity contracts or other resources that can provide shoulder season capacity at a lower cost than coal, as Staff suggested, the analysis is incomplete and does not allow the Commission to determine whether economic cycling reduces costs for customers. Therefore, I

---

[86] Exhibit PAC/100, Wilding/48.
[87] Exhibit PAC/100, Wilding/50.

recommend the Commission reduce PacifiCorp's 2023 TAM expense by $50 thousand.

Q. What does the $50 thousand represent?

A. I appreciate the high degree of arbitrariness in my recommendation of a $50 thousand reduction to the 2023 TAM net power costs (NPC). I believe incremental efficiencies with regard to NPC may be possible and, absent a more thorough analysis by PacifiCorp conclusively demonstrating this, $50 thousand represents approximately 0.003 percent[88] of PacifiCorp's proposed $1.684 billion[89] NPC for 2023. One way of viewing the $50 thousand is that it would not take a great deal of increased efficiency, on a forecasted basis, to achieve a $50 thousand reduction in NPC.

[88] 0.003 percent is three one-thousands of one percent.
[89] Exhibit PAC/100, Wilding/3.

ISSUE 7. COAL PLANT REPORTING REGARDING MINIMUM TAKE MODELING

Q. What information did Sierra Club recommend the Commission require PacifiCorp to provide as part of future TAM filings?

A. As it relates to this issue, Sierra Club recommended the Commission require PacifiCorp to provide for each coal plant for each of the past five years:

1. The initial incremental price;
2. The final dispatch tier price; and
3. The magnitude of the difference between the two prices.[90]

Q. Did the Commission, in Order No. 21-379 for Docket No. UE 390, require PacifiCorp to report, as part of its subsequent TAM filings, certain information price information regarding dispatch of its coal plants and minimum take modeling?

A. Yes. The Commission "require[d] PacifiCorp to provide the information requested by parties."[91] The Commission's requirement was for the following:

1. Initial incremental price;
2. Final dispatch tier price;
3. Spread between the two;
4. Costing tier; and
5. Differential between the initial incremental price and the costing tier price.[92]

Q. Did PacifiCorp provide the information with its TAM filing?

[90] Order No. 21-379, page 11.
[91] Id., see the first paragraph of page 12.
[92] Id., see the second paragraph of page 12.

A. The Company's testimony stated that it would include the required information in its 15-day workpapers.[93] Its pdf file "OR UE-400 ORTAM23 TAM Support Set 3_15-CalDay A-P" identified confidential Excel file "ORTAM23 Four Year TAM Fuel Price Tiers CONF" as the file containing its response pursuant to Order 21-379 specifically regarding:

> Modeling of Minimum Take Levels:….. we require four years [of data], so that the 2023 TAM should include past pricing from the 2020 TAM forward. Four years is consistent with other TAM modeling such as the market caps that are disputed in this proceeding. We also direct PacifiCorp to include the costing tier for each plant for each year, and the differential between the initial incremental price and the costing tier price so parties can consider the variations in the incremental price discount from plant to plant.[94]

Q. What information did PacifiCorp provide in its Excel file?

A. The Company provided **[Begin Confidential]** [redacted]

---

[93] Exhibit PAC/100, Wilding/41.

[94] The third page of confidential file "OR UE-400 ORTAM23 TAM Support Set 3_15-CalDay A-P.pdf."

Confidential Table 2 – 2020 - 2022 Coal Plant Fuel Prices

[redacted]

[END CONFIDENTIAL]

Q. What information did PacifiCorp provide in its spreadsheet for the 2023 TAM?

A. The Company provided the following, which I identify as Confidential Table 3:

[BEGIN CONFIDENTIAL]

Confidential Table 3 – 2023 Coal Plant Fuel Prices

[redacted]

[END CONFIDENTIAL]

Q. How do you characterize the information PacifiCorp provided pursuant to this Commission requirement?

A. The information provided by the Company is incomplete…at best. For years 2020 – 2022 PacifiCorp provided two values for each coal-fired unit: “costing tier” and “incremental tier,” and omitted the requested spread calculation. Additionally, it is unclear to me whether either value also represents the required final dispatch tier price. While the dimensions are unstated in the tables for 2020 through 2022, I understand these to be in dollars per MMBtu.

For 2023, PacifiCorp provides **[Begin Confidential]** [redacted] **[End Confidential]**

I have submitted data requests to clarify the provided information.

Q. Do you provide any analysis of the provided information?

A. Yes. I have calculated the spread (Incremental Tier Price less Costing Tier Price) for the 22 coal-fired units for 2020 – 2022 and provided the results in Confidential Chart 1.

[BEGIN CONFIDENTIAL]

Confidential Chart 1: Incremental Tier Price less Costing Tier Price

[redacted]

[END CONFIDENTIAL]

Q. What do you recommend?

A. PacifiCorp's testimony and associated materials regarding the minimum take analysis does not provide all the information required by the Commission and therefore does not allow Parties to "consider the variations in the incremental price discount from plant to plant." Therefore, I recommend the Commission reduce PacifiCorp's 2023 TAM expense by $50 thousand.

Q. What does the $50 thousand represent?

A. I appreciate the high degree of arbitrariness in its recommendation of a $50 thousand reduction to the 2023 TAM net power costs (NPC). I believe incremental efficiencies with regard to NPC may be possible and, absent a more thorough analysis by PacifiCorp conclusively demonstrating this, $50 thousand represents approximately 0.003 percent[95] of PacifiCorp's proposed $1.684 billion[96] NPC for 2023. One way of viewing the $50 thousand is that it would not take a great deal of increased efficiency, on a forecasted basis, to achieve a $50 thousand reduction in NPC.

Q. Does this conclude your testimony?

A. Yes.

---

[95] 0.003 percent is three one-thousands of one percent.
[96] Exhibit PAC/100, Wilding/3.

CASE: UE 400
WITNESS: STEVE STORM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 601

Witness Qualification Statement

May 25, 2022

WITNESS QUALIFICATION STATEMENT

NAME	Steve Storm
EMPLOYER	Public Utility Commission of Oregon
TITLE	Senior Economist
ADDRESS	201 High Street SE, Suite 100 Salem, OR 97301
EDUCATION	MBA; University of Oregon; AB (Economics); Harvard University

EXPERIENCE I have been employed by the Public Utility Commission of Oregon since October 2018 as a Senior Economist. I was previously employed by the Commission as a Senior Economist 2007-2008, as the Program Manager of the Economic and Policy Analysis section 2008-2012, and as an Economist 4 2012-2013. My responsibilities have included performing as well as leading a team of analysts performing economic and financial research and providing technical support on a wide range of policy issues involving electric, natural gas, and telecommunications utilities. I have sponsored testimony in the following proceedings of the Public Utility Commission of Oregon: Docket Nos. UG 221, UG 388, UE 197, UE 210, UE 213, UE 215, UE 217, UE 233, UE 246, UE 352, UE 369, UE 370, UE 374, and UE 399 (pending).

I have over 35 years of professional experience performing and directing the performing of economic, financial, and other quantitative analysis.

I was employed by NW Natural as a Senior Economist in its IRP team 2013-2018, where my responsibilities included customer and industrial load forecasting; performing cost of service and related financial analysis on a variety of infrastructure projects and alternatives; and preparing quarterly economic information for executive communications.

I was a self-employed financial planner for eight years following an 18-year career in management positions responsible for pricing and cost analysis; financial analysis, planning and management; and strategic planning in the publishing and telecommunications industries. I managed the pricing and cost accounting functions for Pacific Northwest Bell's Directory department and its successor company, US WEST Direct, for five years. I managed the departmental budgeting and management reporting functions at US WEST Direct for three years and had seven years management experience in capital budgeting, financial analysis, and strategic planning functions at US WEST Communications. I managed the corporate financial planning, analysis, and management reporting functions for one year at Electric Lightwave.

CASE: UE 400
WITNESS: STEVE STORM

PUBLIC UTILITY COMMISSION
OF
OREGON

HIGHLY CONFIDENTIAL STAFF EXHIBIT 602

Exhibits in Support
Of Opening Testimony

May 25, 2022

CASE: UE 400
WITNESS: RYAN BAIN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 700

Opening Testimony

May 25, 2022

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

A. My name is Dr. Ryan Bain, PhD. I am an economist employed in the 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 qualification statement is found in Exhibit Staff/701.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to summarize analysis and recommendations on the issues of Other Revenues and Wheeling regarding PacifiCorp's 2023 Transition Adjustment Mechanism (TAM) filing, Docket No. UE 400.

Q. Did you prepare an exhibit for this docket?

A. No.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. OTHER REVENUES

Q. Please describe what Other Revenues are in the context of this filing?

A. PacifiCorp maintains Schedule 205, the TAM Adjustment for Other Revenues, to collect or distribute variations from base revenues included in PacifiCorp's base rates for certain categories or revenues. The category of other revenues in PacifiCorp's 2022 TAM reply testimony included Oregon allocated revenues from Seattle City Light – Stateline Wind Farm of $2,986,282.[1]

Q. How does PacifiCorp propose to treat Other Revenues in the 2023 TAM?

A. As this year's TAM is filed concurrently with the Company's General Rate Case (GRC), Docket No. UE 399, the Company has proposed that Schedule 205 rates be set to zero as the present adjustments are incorporated into base rates through the GRC. The Company will maintain Schedule 205 for future incremental changes in Other Revenues through future TAM filings.[2]

Q. Does Staff have any issues with the Company's proposal?

A. No. Staff has no issue with the Company's proposal and supports maintaining Schedule 205 in place for future use.

---

[1] *See In the Matter of PacifiCorp, dba Pacific Power*, Docket No. UE 390, Order No. 21-379 (November 2, 2021), AWEC's DR 016 – 1st Revised, and PAC's Reply Testimony Exhibit PAC/401 Staples/1 (July 9, 2021). *See also In the Matter of PacifiCorp, dba Pacific Power*, 2011 Transition Adjustment Mechanism, Docket No. UE 216, Order No. 10-363, p. 30 (September 16, 2010).
[2] PAC/400, Ridenour/3.

ISSUE 2. WHEELING

Q. Please describe and discuss wheeling expenses and revenues.

A. Wheeling expenses are expenses that PacifiCorp incurs from delivering power to PacifiCorp's transmission system. PacifiCorp pays different Transmission Providers' Open Access Transmission Tariff (OATT) rates when the Company is transporting power to its transmission system using other Providers' facilities, and conversely charges utilities through the OATT when utilities transmit power over the Company's transmission lines. PacifiCorp recovers wheeling expense through its TAM. The Company's transmission wheeling expense testimony is contained in PAC/100, Wilding/14, lines 17-19. The Company projects a $9.8 million increase in the wheeling expense category due to updated actual 2021 wheeling expense, with roughly $1.95 million of this expense allocated to Oregon.[3]

Wheeling revenues are revenues PacifiCorp collects under its OATT when other utilities use its Transmission System to transmit power. The Company does not include wheeling revenues in its TAM. PacifiCorp maintains that wheeling revenues generated under its OATT are a direct offset to the Company's transmission system revenue requirement used to set retail base rates and are not an offset to wheeling expense.

Q. Do you have a wheeling expense adjustment?

A. Staff is continuing its review of wheeling costs. No adjustments to wheeling expenses are recommended at this moment.

[3] PAC/101, Wilding/1.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 400
WITNESS: RYAN BAIN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 701

Witness Qualifications Statement

May 25, 2022

WITNESS QUALIFICATIONS STATEMENT

NAME:	Ryan Bain
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Analyst Utility Strategy and Integration Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	Ph.D., Economics (2020) Washington State University B.S., Economics (2009) Texas A&M University
EXPERIENCE:	Prior to joining the Oregon Public Utility Commission as a Senior Analyst in the Utility Strategy and Integration Division, I was employed as an economist with a forensic economics consultancy in the Dallas / Fort Worth area. My peer reviewed published research involves understanding information impacts on national and local agricultural commodity markets, and I have presented research on testing the accuracy of various forecasting methods in the case of agricultural commodities before a meeting of economic professionals.

CASE: UE 400
WITNESS: ROSE ANDERSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 800

Opening Testimony

May 25, 2022

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

A. My name is Rose Anderson. I am a Senior Economist employed in the Energy Resources & 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 qualification statement is found in Exhibit Staff/801.

Q. What is the purpose of your testimony?

A. I discuss PacifiCorp's transition from the GRID model to the Aurora model to forecast its net power costs (NPC), including the model validation process and the accuracy of coal fuel price inputs.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Exhibit Staff/802, which is PacifiCorp's response to Data Request No. 57.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. MODEL VALIDATION

Q. Please describe the model validation process for Aurora as provided by PacifiCorp in the 2023 TAM.

A. In advance of the 2023 TAM, PacifiCorp performed concurrent model runs in Aurora and GRID using a forecast of 2021 data separate from any TAM or PCAM forecast. PacifiCorp then checked the output values for the various categories of NPC, and investigated any significant differences.[1] PacifiCorp verified that the variation in total NPC between the two results was about 0.8 percent.

Q. Does Staff view this model validation process as adequate?

A. Not entirely. This model validation process is useful and adequate for the 2023 TAM given that it compares the results of Aurora to GRID. However, for a thorough model validation process, Staff expected a backcast model validation process similar to the GRID validation process performed by PacifiCorp in the 2019 TAM as directed in Order No. 17-444. This backcast used actual 2016 input data in GRID to create a forecast of 2016 NPC for comparison to 2016 actuals. PacifiCorp included a discussion of this backcast validation exercise and a table comparing it to 2016 actual data in the 2019 TAM.[2]

However, in the 2023 TAM, by using forecast 2021 data as the model validation inputs instead of actual 2021 data, the transparency of the model validation has been reduced. The use of forecast 2021 data also limits the

[1] Staff/802, PacifiCorp's response to Staff DR 057.
[2] Docket No. UE 339 PacifiCorp/100, Wilding, 21.

opportunity for further discussion through comparison to actuals. A backcast using actual data will be an important part of fully validating the Aurora model for use in power cost filings.

Q. Does Staff have a recommendation for an improvement on PacifiCorp's model validation process?

A. Yes. PacifiCorp should provide backcast model validation runs similar to the backcast provided in Docket No. UE 339. The backcasts should use actual 2022 and 2023 data, respectively, while keeping all other inputs and assumptions the same as those in the relevant TAM. PacifiCorp should provide the first validation run in connection with its 2024 TAM and the second in connection with its 2025 TAM.

For reference, the excerpt below from PacifiCorp's testimony in the 2019 TAM describes the backcast that was defined and agreed to by parties:

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.[3]

Comparing the results of a backcast model run to the actual NPC results in the PCAM will provide parties with similar confidence in the Aurora model's ability to accurately forecast each element of NPC as was gained through the 2019 TAM model validation exercise for the GRID model.

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

ISSUE 2. COAL FUEL PRICE TIERS

Q. Please describe the change in coal pricing between the 2022 TAM and the 2023 TAM.

A. The 2022 TAM used GRID to dispatch coal plants. Because GRID is unable to model multiple price tiers, an iterative adjustment was made to the coal fuel costs to ensure coal plants generated at their minimum take levels. In this iterative adjustment, coal prices were adjusted downward in order to cause the GRID model to dispatch the plants at a higher level, and then the model was rerun iteratively until all coal plants generated above their minimum take requirement. Then, an outboard adjustment to coal fuel costs was implemented so that total coal costs would continue to accurately reflect coal fuel prices.

In the 2023 TAM, Aurora was used to model the various price tiers of each coal contract directly. Because Aurora is capable modeling of coal fuel price tiers directly, no iterative or outboard adjustments were required.

Q. What did Staff do to verify that coal price tiers were modeled adequately in the 2023 TAM?

A. Staff reviewed the Aurora workpapers provided by PacifiCorp and verified that multiple fuel tier inputs were used at each plant. Staff's review of the accuracy of the fuel tier inputs is ongoing.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 400
WITNESS: ROSE ANDERSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 801

Witness Qualifications Statement

May 25, 2022

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 net present value revenue requirement and load forecasts, in Rate Cases and planning dockets. I have participated in OPUC rate cases including UE 319, UG 325, and UG 344, and OPUC power cost dockets including UE 320, UE 323, UE 333, and UE 335. 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 400
WITNESS: ROSE ANDERSON

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 802

Exhibits in Support Of Opening Testimony

May 25, 2022

OPUC Data Request 57

Model Validation - See PAC/100, Wilding/17-18. Please define and explain broadly what data was used for the Aurora/GRID model validation run. For example, was the data historical or based on a forecast? If it was a forecast, what forecast was used and please explain how validation can be verified based solely on a forecast?

Response to OPUC Data Request 57

PacifiCorp conducted a process to develop and refine AURORA to model PacifiCorp's system. The final result of that process was the validation runs provided with the direct testimony of Company witness, Michael G. Wilding, specifically Confidential Exhibit PAC 103 and Confidential Exhibit PAC 104.

The input data used was forecast data at the time the studies were done. The inputs between the two models were the same. The total net power costs (NPC) from the two models were compared and reviewed for reasonableness which included ensuring that the deviation in the total NPC was within a reasonable range.

CERTIFICATE OF SERVICE

UE 400

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 25th day of May, 2022 at Salem, Oregon

____

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

MARY ANNE COOPER **(C)** **(HC)** OREGON FARM BUREAU FEDERATION	1320 CAPITOL ST NE STE 200 SALEM OR 97301 maryanne@oregonfb.org
AWEC	
BRENT COLEMAN **(C)** **(HC)** DAVISON VAN CLEVE, PC	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
TYLER C PEPPLE **(C)** **(HC)** DAVISON VAN CLEVE, PC	1750 SW HARBOR WAY STE 450 PORTLAND OR 97201 tcp@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
CUB	
JENNIFER HILL-HART **(C)** **(HC)** OREGON CITIZENS' UTILITY BOARD	610 SW BROADWAY STE 400 PORTLAND OR 97205 jennifer@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 **(C)** **(HC)** OREGON CITIZENS' UTILITY BOARD	610 SW BROADWAY, STE 400 PORTLAND OR 97205 dockets@oregoncub.org
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)** SOMACH SIMMONS & DUNN, PC	500 CAPITOL MALL, STE 1000 SACRAMENTO CA 95814 psimmons@somachlaw.com
NEWSUN ENERGY	
BRITTANY ANDRUS No Business Name	3317 NE 31ST AVENUE PORTLAND OR 97212 andruspdx@gmail.com
JACOB (JAKE) STEPHENS NEWSUN ENERGY	3500 S DUPONT HWY DOVER DE 19901 jstephens@newsunenergy.net
MAX YOKLIC NEW SUN ENERGY LLC	2033 E. SPEEDWAY BLVD, SUITE 200 TUCSON AZ 85719 myoklic@newsunenergy.net
NIPPC	
CARL FINK **(C)** BLUE PLANET ENERGY LAW LLC	628 SW CHESTNUT ST, STE 200 PORTLAND OR 97219 cmfink@blueplanetlaw.com
SPENCER GRAY NIPPC	sgray@nippc.org
PACIFICORP	
PACIFICORP, DBA PACIFIC POWER	825 NE MULTNOMAH ST, STE 2000 PORTLAND OR 97232 oregondockets@pacificorp.com
AJAY KUMAR **(C)** **(HC)** PACIFIC POWER	825 NE MULTNOMAH STE 800 PORTLAND OR 97232 ajay.kumar@pacificorp.com
SIERRA CLUB	
ANA BOYD **(C)** **(HC)** SIERRA CLUB	2101 WEBSTER ST STE 1300 OAKLAND CA 94612 ana.boyd@sierraclub.org
ROSE MONAHAN **(C)** **(HC)** SIERRA LCU	2101 WEBSTER ST STE 1300 OAKLAND CA 94612 rose.monahan@sierraclub.org
STAFF	
STEPHANIE S ANDRUS **(C)** **(HC)** PUC STAFF--DEPARTMENT OF JUSTICE	BUSINESS ACTIVITIES SECTION 1162 COURT ST NE SALEM OR 97301-4096 stephanie.andrus@doj.state.or.us
MOYA ENRIGHT **(C)** **(HC)** PUBLIC UTILITY COMMISSION OF OREGON	PO BOX 1088 SALEM OR 97308 moya.enright@puc.oregon.gov

VITESSE LLC	
DENNIS BARTLETT **(C)** META PLATFORMS, INC.	dbart@fb.com
JACOB MCDERMOTT **(C)** META PLATFORMS, INC.	jacobmcdermott@fb.com
IRION A SANGER **(C)** SANGER LAW PC	1041 SE 58TH PLACE PORTLAND OR 97215 irion@sanger-law.com