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June 9, 2021

***Via Electronic Filing -***

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

**RE: Docket No. UE 390– In the Matter of PACIFICORP, dba PACIFIC POWER, 2022 Transition Adjustment Mechanism.**

Attached are documents for Staff Opening Testimony

Exhibit 100-104 Enright, Confidential Exh 100 & 102
Exhibit 200-203 Cohen, Confidential Exh 200 & 203 in electronic
Exhibit 300-303 Hanhan, Confidential Exh 300, 302 & 303 in electronic
Exhibit 400-403 Fjeldheim, Confidential Exh 400 & 403
Exhibit 500-503 Zarate, Confidential Exh 500 & 503
Exhibit 600-602 Fox, Confidential Exh 600 & 602
Exhibit 700-703 Anderson, Confidential Exh 700, page 9-10 & 15 are Highly Conf
Exhibit 800-804 Dlouhy, Confidential Exh 800 & 802 and
Exhibit 900-901 Gibbens

/s/ Kay Barnes
Kay Barnes
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CERTIFICATE OF SERVICE

UE 390

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 9th day of June, 2021 at Salem, Oregon

/s/ Kay Barnes

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CASE: UE 390
WITNESS: MOYA ENRIGHT

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 100

# Testimony

**June 9, 2021**

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

A. My name is Moya Enright. I am a Senior Economist employed in the Energy Rates Finance and Audit Division of the Public Utility Commission of Oregon (OPUC or Commission). 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 the 2022 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, before introducing the three focus areas of Staff's approach to this filing: forecasted expenses and revenues; modelling; and policy issues. I then present a summary of the adjustments and recommendations made by Staff, including detail of where each topic is discussed in this filing.

The second section of my testimony addresses PacifiCorp's compliance with the TAM guidelines and compliance with the previous TAM order in this filing.

Finally, I address EIM benefits. I discuss my analysis of the Company's GHG benefit forecast, flexible ramping reserve benefit forecast, and forecasted EIM costs. Finally, I address PacifiCorp's calculation of historic inter-regional energy transfer benefits, which is a direct input to the Energy benefit forecasting model discussed by Staff witness Dr. Dlouhy in Staff/800, Issue 1.

**Q. Did you prepare any additional exhibits for this docket?**

A. Yes. I prepared the following Staff Exhibits:

- Staff/101: Witness Qualification Statement
- Staff/102: PacifiCorp responses to Data Requests, including relevant attachments
- Staff/103: California Carbon Allowance and California Carbon Offset prices.
- Staff/104: Documents detailing REC use in CARB compliance.

**Q. How is your testimony organized?**

A. My testimony is organized as follows:

## OVERVIEW OF 2022 TAM FILING

**Q. Please summarize PacifiCorp's 2022 TAM filing.**

A. The Company has forecasted 2022 Net Power Costs (NPC) of $1,455 million in its initial filing, representing an increase of approximately $45.1 million, or 3.2 percent, versus the final 2021 NPC forecast.[1]

**Q. What is the effect on an Oregon basis?**

A. On an Oregon-allocated basis, forecasted 2022 NPC are $372 million. This represents a $16.8 million, or 4.7 percent, increase on the 2021 NPC forecast.[2] This increase is seen in conjunction with a load increase of 75 GWh, or 0.5 percent in Oregon, bringing the annual Oregon load forecast to 15,295 GWh. Increased Oregon load is said to account for $3.3 million of the overall increase in NPC.[3]

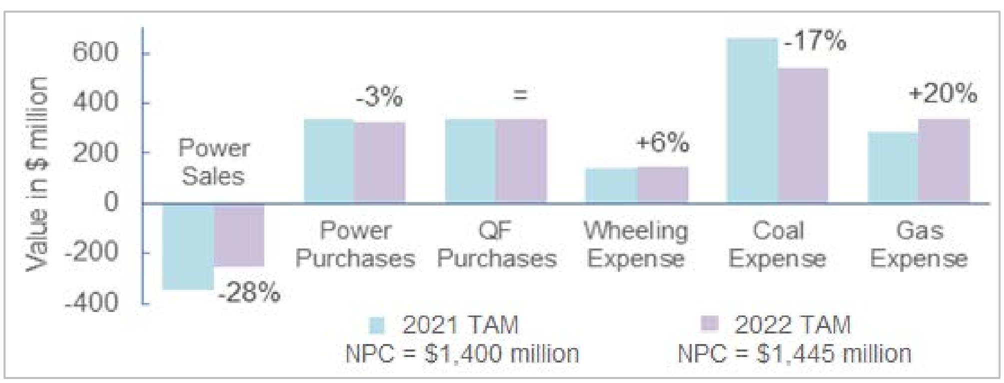


*Figure 1 - 2021 Final Forecast vs. 2020 Initial Forecast [4,5]*

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1 PAC/101, Webb/1, line 35. Represents gross NPC, e.g. NPC forecasted by the GRID inclusive of EIM benefits. This value is reduced by Production Tax Credits and Oregon situs adjustments prior to inclusion in customer rates.

2 Ibid.

3 PAC/101, Webb/3, lines 17 – 18.

4 PAC/101, Webb/1, and UE 375 Compliance Tariff Sheets, Attachment 3, Page 1 of 3. Values are inclusive of EIM benefits, which serve as an offset to costs.

5 Note that forecasted geothermal generation costs of $4 million have been excluded from this chart for simplicity.

**Q. What has changed since last year's filing?**

A. PacifiCorp's initial filing forecasts a 28 percent ($97 million) reduction in revenue from power sales, and 17 percent ($114 million) reduction in coal expenses. Gas expenses are forecasted to increase by 20 percent ($56 million). Year-on-year changes between expenses and revenues forecasted in the 2022 TAM and 2021 TAM are summarized in Figure 1 above.

The overall changes in costs tally with the change in forecasted fuel mix. The 2022 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 previous year's forecast. This is offset by gas generation increasing from **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** percent to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** percent of the Company's projected generation. The proportions of each fuel type are summarized in confidential Figure 2.

**[BEGIN CONFIDENTIAL]**

[redacted] [6,7]

*Figure 2 - Confidential Breakdown of Forecasted Generation by Fuel Type*

[6] Staff/102, Enright/33 (attachment to PacifiCorp's first supplemental response to Staff DR 114 (confidential)).

[7] Note that forecasted geothermal generation of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** has been excluded from this chart for simplicity.

**[END CONFIDENTIAL]**

Other forecasted generation sources are forecasted to generate **[BEGIN CONFIDENTIAL]** [redacted] **[BEGIN CONFIDENTIAL]** the previous year's TAM, although notably forecasted wind generation **[BEGIN CONFIDENTIAL]** increased from **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** percent of generation in the 2021 TAM, and is forecasted to remain elevated at **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** percent of PacifiCorp's generation in the 2022 TAM year.

**Q. What modelling changes has PacifiCorp included in this filing?**

A. The Company has not moved to using the AURORA model to forecast NPC in this filing, as had been the expectation during the filing and settlement of the 2021 TAM.[8] PacifiCorp states that their transition to AURORA was delayed due to the COVID-19 pandemic.[9]

Nevertheless, the Company has included two changes to its GRID model, despite this being the final year of its use.

- First, PacifiCorp has proposed a change to the calculation of "Market Caps," which constrain GRID's forecasting of wholesale sales and purchases volumes.

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8 UE 375 - Stipulating Parties/100, Webb, Gibbens, Jenks, Higgins, Kaufman, Burgess, Reed, Dickman/1, lines 13 - 14.

9 PAC/100, Webb/23, lines 12 - 17.

- Second, PacifiCorp has removed the "must run" setting.[10] This modelling change was agreed to in settlement of the 2021 TAM, but was envisioned to take place in the AURORA model rather than GRID.[11]

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

A. Staff's review focuses on three areas: forecasted expenses and revenues; modelling; and policy issues.

Staff's analysis pays particular attention to the issues raised by the Commission in its approval of the settlement stipulation in the 2021 TAM filing, including the effect of Production Tax Credits on Net Power Costs and Coal Supply Agreements. Staff also addresses the issues raised by the Commission in the first Issues List of the current docket, published on May 21, 2021.

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

A. Staff's proposed adjustments total **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** on a total-company basis, and **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** on an Oregon-allocated basis. Including Staff's adjustments in the forecast of NPC would lead to an overall increase in Oregon NPC of **[BEGIN CONFIDENTIAL]** [redacted][12] **[END CONFIDENTIAL]** compared with 2021 NPC, or a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** percent increase in NPC.

[10] In the settlement stipulation to the prior year's TAM, PacifiCorp agreed to the removal of the "must run" setting as part of its transition to AURORA. The Company has implemented this change in GRID due to the delayed implementation of the AURORA model. PAC/100, Webb/14, lines 16 – 17.

[11] PAC/100, Webb/14, lines 15 – 17.

[12] Measured excluding Oregon situs and PTC adjustments, as shown in PAC/101, Webb/1, line 35.

**[BEGIN CONFIDENTIAL]**

| # | Issue | System-Wide ($ millions) | Oregon-Allocated ($ millions) |
|---|---|---|---|
| 1 | EIM GHG | [redacted] | [redacted] |
| 3 | Wheeling | [redacted] | [redacted] |
| 4 | PURPA QFs | $ (5,778,000) | $ (1,530,000) |
| 5 | Huntington | [redacted] | [redacted] |
| 7 | EIM Energy | $ 1,746,000 | $ 452,000 |
| 8 | Market Caps | $ (19,700,000) | $ (5,100,000) |
| 9 | NPM | $ (8,400,000) | $ (2,224,000) |
| **Total Adjustments** | | **$ (35,852,800)** | **$ (9,378,000)** |
| Forecasted NPC | | $ 1,445,454,540 | $ 372,213,874 |
| **NPC after adjustments** | | **$ 1,409,601,740** | **$ 362,835,874** |

*Figure 3 - Confidential Effect of Staff Adjustments on Forecasted NPC*

**[END CONFIDENTIAL]**

**Q. What forecasted expenses and revenues has Staff's testimony addressed?**

A. Staff's review includes each of the six major of expenses and revenue sources shown in Figure 1.

Staff/100 provides an overview of the filing, a review of the Company's compliance with the TAM guidelines and past settlement agreements, and of the Company's EIM benefits forecasts.

In Staff/200, witness Heather Cohen forecasted wholesale power purchase expenses of $327 million, and forecasted wholesale power sales revenue of $252 million. Ms. Cohen undertakes an in-depth review of PacifiCorp's wholesale trading operations and hedging policies, providing insight into volumes of power trading in recent years, and the Company's developing trading relationship with CAISO. Finally, Ms. Cohen addresses the Company's DA-RT adjustment, and the Company's Official Forward Price Curve (OFPC) and Scalar Methodology.

In Staff/300, witness Nadine Hanhan addresses the Company's forecasted wheeling expenses of $148 million. Ms. Hanhan also provides an overview of how wheeling expenses forecasted in the TAM have evolved in recent years, and presents an update on wheeling revenues related to the proposed CAISO Extended Day Ahead market (EDAM).

In Staff/400, witness Brian Fjeldheim addresses the Company's forecasted gas expense of $339 million. Mr. Fjeldheim's analysis includes discussion of gas prices, gas contracts, gas storage, and gas transport. Further, Mr. Fjeldheim discusses the issue of Gas Optimization.

In Staff/500, witness Kathy Zarate addresses the Company's forecasted generation from Qualifying Facilities (QF), and the associated power purchase expense of $337 million. Ms. Zarate also addresses the standard inputs to the GRID model, "Other Revenues," and the Consumer Opt-Out Charge.

Finally, in Staff/600, witness John Fox addresses the Company's projected Coal Expense of $543 million.

**Q. What policy issues are addressed by Staff?**

A. In Staff/700, witness Ms. Anderson addresses the five new coal supply agreements, and the Huntington coal supply agreement; provides testimony regarding the inclusion of minimum take levels in the NPC forecast; and dives into the Economic Coal Cycling Study which was provided in compliance with the 2021 TAM settlement stipulation.[13]

**Q. What modelling issues are addressed by Staff?**

A. The testimony of Mr. Fox (Staff/600) addresses the removal of the must-run condition for coal generating units in GRID.

In Staff/800, witness Dr. Curtis Dlouhy addresses the Company's proposal to change its approach to modeling Market Caps. Dr. Dlouhy also conducts an in-depth review of the EIM energy benefits model, a model which to date has not yet been accepted by Staff or Parties.

In Staff/900, witness Scott Gibbens addresses the Company's modelling of wind capacity factors, and the resulting Production Tax Credits associated with wind generation. Mr. Gibbens also deals with the Nodal Pricing Model, load forecast, the allocation of costs between states, and rate spread calculations.

**Q. Has Staff proposed any adjustments?**

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

1. Three adjustments to the GHG benefit forecast, as detailed in Staff/100, Issue 2. The combined effect of the adjustments is a **[BEGIN CONFIDENTIAL]** [redacted] **[BEGIN CONFIDENTIAL]** decrease in NPC on a system-wide basis, or approximately **[BEGIN CONFIDENTIAL]**

[13] UE 375 – Stipulation at 20; UE 375 – Stipulating Parties/100, Webb, Gibbens, Jenks, Higgins, Kaufman, Burgess, Reed, Dickman/16.

[redacted] **[BEGIN CONFIDENTIAL]** on an Oregon-allocated basis. The individual adjustments are as follows:

I. Adjustment relating to the growth factor, resulting in a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** decrease in system-wide NPC.

II. Adjustment to the historic period used in the GHG forecast, resulting in a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** decrease in NPC on a system-wide basis.

III. Adjustment to reflect CCA price growth regardless of generation source, resulting in a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** decrease in NPC on a system-wide basis.

2. Adjustment relating to wheeling cost inputs, described in Staff/300, Issue 1. This represents a total-company decrease in NPC of **[BEGIN CONFIDENTIAL]** [redacted], **[END CONFIDENTIAL]** or **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** decrease on an Oregon-allocated basis.

3. Adjustment relating to forecasted generation from Qualifying Facilities, as discussed in Staff/500, Issue 4. This represents a total-company decrease to NPC of $5.8 million, or $1.53 million decrease on an Oregon-allocated basis.

4. Remove the minimum take assumptions from the modeling associated with the most recent Huntington contract in the 2022 TAM, as discussed in Staff/700, Issue 3. This adjustment is expected to result in a reduction to

NPC of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** Oregon-allocated.

5. Adjustment related to the Company's method of forecasting EIM benefits detailed in Staff/800, Issue 1, resulting in a decrease in forecasted EIM benefits flowing through to customers. This represents a total-company increase to NPC of $1.746 million, or $452,000 increase on an Oregon-allocated basis.
6. Rejection of the Company's proposed change to Market Caps detailed in Staff/800, Issue 2, resulting in an increase in forecasted off-system sales. This represents a total-company decrease to NPC of $19.7 million, or $5.1 million on an Oregon-allocated basis.
7. Adjustment designed to match the benefits of the Nodal Pricing Model (NPM) model to the incremental costs paid by customers for the NPM detailed in Staff/900, Issue 3. This results in a $8.4 million decrease to NPC (total-company), or $2.1 million on an Oregon-allocated basis.

**Q. Has Staff made any other recommendations?**

A. Yes. Staff's recommendations are summarized as follows:

1. Recommendation regarding PacifiCorp's California Air Resources Board (CARB) compliance costs.
2. Recommendation regarding workshops addressing the DA-RT Adder in advance of the 2023 TAM filing, discussed in Staff/200, Issue 1.
3. Recommendation regarding a review of the DA-RT Adder to justify its inclusion in the AURORA model of NPC, as discussed in Staff/200, Issue 1.

4. Recommendation regarding reporting on gas optimization benefits, as detailed in Staff/400, Issue 2.
5. Recommendation regarding a follow-up Economic Coal Cycling Study with input from Staff and other interested stakeholders to inform the next TAM, as detailed in Staff/700, Issue 1.
6. Recommendation regarding necessary improvements to the generation forecasting methodology used to inform coal contract negotiations for future contracts, as discussed in Staff/700, Issue 3.
7. Recommendation to remove the minimum take assumptions associated with the Huntington contract from TAM filings moving forward, as discussed in Staff/700, Issue 3.
8. Recommendation to remove the minimum take assumptions associated with certain new coal supply agreements from TAM filings moving forward, pending the outcome of an updated Economic Cycling Study, as discussed in Staff/700, Issue 3.
9. Recommendation regarding reporting on PTCs, detailed in Staff/900, Issue 2.
10. Recommendation to be applied if Adjustment 7 detailed on page 11 above is not pursued, regarding a deferral to track benefits accrued from utilizing the NPM in operations, as discussed in Staff/900, Issue 3.

**Q. Are further updates expected in the docket?**

A. Yes. In accordance with the TAM Guidelines, PacifiCorp will include the most recent official forward price curve (OFPC) in its reply testimony, which is due to be published on July 9, 2021. The Company will provide two further updates to the OFPC in the November indicative update on November 8, 2021, and the November final update on November 15, 2021.

## ISSUE 1: COMPLIANCE WITH 2021 TAM ORDER AND TAM GUIDELINES

**Q. What were the compliance implications of the 2021 TAM order?**

A. In Order No. 20-392, the Commission adopted through the stipulation or otherwise ordered several provisions which required further action by the Company and parties. They include:

- Holding a workshop on the transition from GRID to AURORA;
- Providing one model run per intervenor;
- Removal of 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;
- Addressing the reasonableness of modeling minimum take provisions in GRID;
- Providing additional information on CSAs;
- Providing quarterly reports on plant operations and market conditions;
- Providing additional information on wholesale sales;
- Providing additional information on CAISO's calculation of EIM benefits, and make related documentation available for review;
- Providing a sample calculation of Schedule 296 within 30 days of filing the TAM; and
- Providing information on NPC benefits from Company owned wind projects.[14]

[14] In Order No. 20-392, the Commission also ordered PacifiCorp to explain in its Indicative Filing its Production Tax Credit (PTC) agreement in paragraph 18 of the stipulation.

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

A. As noted in the Company's opening testimony, PacifiCorp has not yet been able to implement AURORA for use in the TAM.[15] As such, the Company has not yet held a workshop on the transition or implications for the day-ahead/real-time adjustment or the new nodal price dispatch mechanism. However, it is Staff's understanding that the Company still intends to hold a workshop prior to the 2023 TAM to address the transition and allow parties to gain a better understanding prior to the commencement of a contested case.

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

A. Staff is unaware if the Company has complied with this provision in the Order; however, Staff expects any party who has not been able to receive a model run from the Company will raise this issue in its opening testimony. Staff also notes that the Stipulation 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.[16]

**Q. Did the Company comply with the Commission's order as it relates to coal issues?**

A. Generally, yes. 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. Staff

[15] PAC/100, Webb/23, line 12.
[16] Order No. 20-392, Appendix A at 5.

has concerns about the implementation of the informational model run and minimum take assumptions. Staff's further review of coal related issues can be found in the testimonies of Staff witnesses John Fox and Rose Anderson (Staff/600 and Staff/700).

**Q. Has the Company provided quarterly reports on market conditions and its coal fleets operations?**

A. The Company has thus far provided Staff and stakeholders with a single workshop on these issues, which took place on May 14, 2021

**Q. What is Staff's opinion of the initial report to stakeholders on market conditions and coal fleet operations?**

A. Staff found the workshop informative; however, Staff believes that the Company could more clearly address the concern raised by parties related to the Company's actual coal operations, the uneconomic running of coal plant, and market conditions. Staff believes the workshop provided simply a broad overview of the company's generation during the quarter, with limited detail on the operations of coal plant.

**Q. Does Staff have a recommendation regarding future quarterly operational updates?**

A. Staff makes no formal recommendation at this time. Staff will work with the Company to ensure the meetings are beneficial to all stakeholders and raise any further concerns before the Commission if progress is not made.

**Q. Has the Company provided additional information on the CAISO EIM benefit methodology, including making the additional supporting documentation that is available to PacifiCorp available for review?**

A. No. PAC/100, Webb/8, simply provides a cursory explanation of the CAISO benefit methodology, and reference to the CAISO website.

In spite of PacifiCorp's commitment in the UE 375 stipulation,[17] there have been multiple instances in this filing where PacifiCorp has not been forthcoming with the data requested by Staff,[18] requiring repeated engagement by staff, and multiple supplemental responses to Staff Data Requests (DR).

**Q. Did the Company provide additional and sufficient information on wholesale sales?**

A. Yes. In the 2021 TAM stipulation, parties requested that the Company provide additional information on wholesale sales which included: the past year's bilateral trades for each hour, total wholesale sales revenue, total energy delivered through wholesale sales, hourly generation for Company-owned generation, and monthly generation unit production costs.

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[17] "PacifiCorp agrees to provide additional information on the California Independent System Operator's (CAISO) calculation of EIM benefits, including making the additional supporting documentation that is available to PacifiCorp available for review." UE 375 – Stipulation at 19 (c); UE 375 – Stipulating Parties/100, Webb, Gibbens, Jenks, Higgins, Kaufman, Burgess, Reed, Dickman/16.

[18] Staff/102, Enright/2 - 6 (PacifiCorp's first and first supplemental responses to Staff DR 19); Staff/102, Enright/8 - 14 (PacifiCorp's first, first supplemental, and second supplemental responses to Staff DR 26); Staff/102, Enright/22 - 31 (PacifiCorp's first, first supplemental, first revised, and second supplemental responses to Staff DR 31); Staff/102, Enright/39 - 40 (PacifiCorp's response to Staff DR 150); Staff/102, Enright/41 (PacifiCorp's response to Staff DR 151).

**Q. Did the Company provide a sample calculation of Schedule 296 within 30 days of filing the TAM?**

A. Yes. PacifiCorp provided the sample calculation to stakeholders on May 3, 2021. Staff has reviewed the calculation and finds it to reflect the approved methodology.

**Q. Did the Company provide additional and sufficient information on the benefits of the Company owned wind projects?**

A. Yes. The Company provides the information requested in its initial testimony. Staff discusses its review of the Company's PTC and wind generation forecast in Staff/900, Issue 2. Staff notes that the wind capacity factor and PTC forecast is reviewed by Staff through Company workpapers in every TAM, but does not receive the NPC benefit forecast without specific discovery or a Staff operated GRID run. As such, Staff believes it would be beneficial to stakeholders and the Commission to require the Company to provide a comparison between the forecasted NPC benefits of the Company owned-wind projects and the benefit forecasts made to justify the investment.

**Q. Does Staff have a recommendation regarding this issues?**

A. Yes. Staff recommends that the Commission direct the Company to continue to provide a discussion of the PTC and NPC benefits of its Company-owned renewable resources, and to also include a comparison to the benefit forecasts made to justify the investment, matching the dates used in the capacity factor methodology currently approved by the Commission.

**Q. Did the Company have any other filing requirements and did it meet those?**

A. Yes, there are other filing requirements. The Company has to comply with the TAM Guidelines set forth in Commission Order No. 09-274. Staff has reviewed the Company's filing and finds that they have thus far complied with the TAM Guidelines in the 2022 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 these future events, however in its initial filing, the Company has complied with the Commission directive.

## ISSUE 2: EIM BENEFITS

**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,[19] GHG benefits, and flex reserve benefits.

Energy transfer benefits are measured in dollars. The Company's energy transfer benefit is forecasted using a regression model. The model uses historic energy transfer benefits and forecasted market variables to predict a future EIM benefit. The 2022 TAM includes **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in energy transfer benefits on a system wide basis, an increase of **[BEGIN CONFIDENTIAL]** [redacted][20] **[END CONFIDENTIAL]** from the 2021 TAM.

GHG benefits are also measured in dollars. These benefits are calculated with reference to the Company's historic GHG revenue from EIM, less compliance costs with 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,

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[19] Note that PacifiCorp uses the term "inter-regional EIM benefits," while the California Independent System Operator's (CAISO) uses the term "inter-regional transfers."
[20] PAC/100, Webb/4, line 9.

a **[BEGIN CONFIDENTIAL]** [redacted][21] **[END CONFIDENTIAL]** from the 2021 TAM.

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. In the 2022 TAM, reserve benefits amount to a **[BEGIN CONFIDENTIAL]** [redacted][22] **[END CONFIDENTIAL]** reduction in required reserves.[23]

As the benefits of the Company's EIM participation cannot be forecasted by the GRID 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. 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.

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[21] PAC/100, Webb/4, line 10.

[22] Staff/102, Enright/7 (attachment to PacifiCorp's first supplemental response to Staff DR 19 (confidential)).

[23] The Company does not provide the dollar value of this reduction in reserve requirement in its filing, nor did it provide this detail when requested in Staff discovery. Staff/102, Enright/2 - 4 (PacifiCorp's first response to Staff DR 19); Staff/102, Enright/39 - 40 (PacifiCorp's response to Staff DR 150). Staff expects that the dollar value of this reserve reduction can easily be gauged by the Company by performing a comparative GRID run absent the reduction, and such an analysis would be valuable in the context of the Commission's issues list in this docket, published May 21, 2021.

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

A. In my testimony, I will first provide a short overview of changes in the EIM over the past year. I will then address each of the three categories of EIM benefits forecasted by PacifiCorp. Finally, I review EIM related costs.

I will recommend one correction to the GHG benefits forecast, and two common-sense adjustments to the GHG benefits forecast, which promote consistency across the Company's forecasts, and result in a total system-wide increase of [redacted] in EIM benefits flowing through to customers.

**Q. Do any other Staff members review EIM related issues?**

A. Yes. Staff's review of energy transfer benefits is discussed in Staff/800, Issue 1, where Staff witness Dr. Dlouhy provides valuable insight to the forecasting model proposed by the Company. Dr. Dlouhy presents the strengths and weaknesses of the Company's model, and recommends an adjustment to the model, resulting in a significant improvement in the predictive power of the model.

In Staff/300, witness Ms. Hanhan also addresses an issue pertinent to EIM, providing an update on the Extended Day Ahead Market (EDAM).

**Q. Please describe the inputs which informed Staff's analysis of EIM benefits.**

A. Staff's research included engaging in a workshop with the Company in May 2021, engaging with the Company through substantial discovery on this topic, and incorporating information from outside sources to inform this testimony.

Staff analyzed calculations performed by the Company, verified data inputs, audited costs, and queried the Company's processes. Staff also investigated the Company's GHG compliance under CARB.

**ISSUE 1, PART 1 - EIM 2021 UPDATE**

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

A. The EIM has expanded further over the past year with the addition of three new utilities, Los Angeles Department of Water & Power, Public Service Company of New Mexico, and Turlock Irrigation District.

Following this expansion, the EIM footprint now includes portions of Arizona, California, Idaho, Nevada, Oregon, Utah, Washington, Wyoming, New Mexico, and the Canadian province of British Columbia.

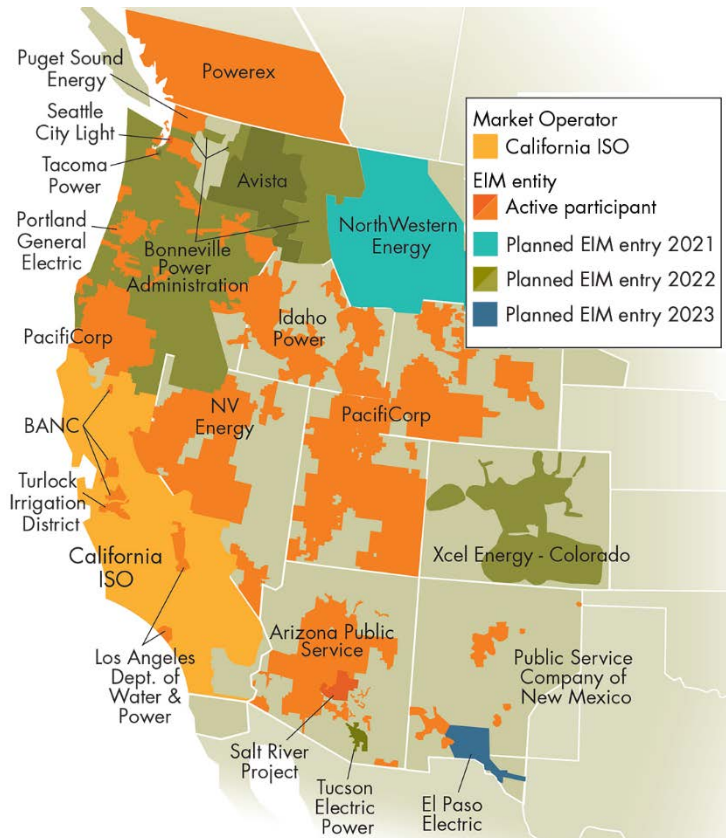


*Figure 4 - Map of Current Participants in EIM*

**Q. Is further expansion of the EIM planned?**

A. Yes. An additional eight entities have committed to joining the EIM over the next two and a half years, including utilities in Montana, Washington, Arizona, Colorado, and New Mexico, along with the AvanGrid Renewables Northwest Balancing Authority (BA).[24]

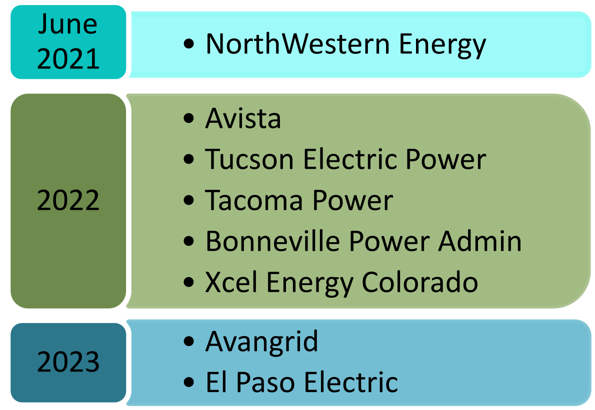


*Figure 5 - List of Future EIM participants*

Including the new entrants announced to date, by 2023 EIM participants will represent over 83 percent of the load within the Western Electricity Coordinating Council (WECC).[25]

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

A. Yes. Staff's understanding that an EDAM is still in consideration, but has been delayed by the CAISO switching its focus to resource adequacy in advance of the 2021 summer season. CAISO has not yet communicated when it intends to continue the initiative.[26] Staff intends to continue to monitor this issue outside of the current TAM filing.

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[24] AvanGrid's BA is a renewable generation resource-only BA including AvanGrid's assets interconnected to Bonneville Power Administration transmission in WECC.

[25] Western Energy Imbalance Market News Release April 1, 2021. See: www.caiso.com/Documents/LADWP-and-Public-Service-Company-of-New-Mexico-Join-the-EIM.pdf.

[26] Staff/102, Enright/37 (PacifiCorp's response to Staff DR 130).

## ISSUE 1, 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, reflecting their GHG compliance cost for power exported to California. This 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).[27]

If CAISO determines that GHG emitting generation at a node within PacifiCorp's BAs served California load, both GHG emitting and non-GHG emitting resources generating at that node will be paid the GHG bid adder of the marginal unit.[28]

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

[28] 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. 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 generation "deemed delivered" to California.

For PacifiCorp's thermal units, the ratio of GHG revenue to generation incurring a compliance obligation has historically been **[BEGIN CONFIDENTIAL]** [redacted].[29] **[END CONFIDENTIAL]**

Hydro generation in EIM incurs no compliance obligation. Hydro generation typically represents **[BEGIN CONFIDENTIAL]** [redacted] [30] **[END CONFIDENTIAL]** percent of the Company's GHG revenues.

Considering both generation sources combined,[31] the Company's ratio of GHG revenue to generation incurring a compliance obligation is **[BEGIN CONFIDENTIAL]** [redacted].[32] **[END CONFIDENTIAL]**

**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

[29] Staff/102, Enright/15 (attachment to PacifiCorp's second supplemental response to Staff DR 26 (confidential)).
[30] Staff/102, Enright/18 (attachment to PacifiCorp's response to Staff DR 27 (confidential)).
[31] Although some of PacifiCorp's wind generator units participate in EIM, it last earned GHG revenue on generation from wind resources in **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]** Staff/102, Enright/36 (PacifiCorp's response to Staff DR 129); Staff/102, Enright/32 (attachment to PacifiCorp's response to Staff DR 33 (confidential)).
[32] This value represents that historically, for every 100 MWh of PacifiCorp's generation receiving GHG revenue, only **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of that generation incurs a compliance obligation.

create a naïve forecast[33] of future benefits, with adjustments for growth in GHG prices and seasonal shaping.

**Q. Please provide more detail on the first step, the calculation of historic GHG benefits.**

A. GHG benefits are calculated simply as the sum of GHG revenue for a generator type, minus the cost of compliance with CARB.

- For hydro generator units, the compliance cost is zero.
- For thermal generator units, the compliance cost is calculated as the portion of generation deemed delivered to California, multiplied by the California Carbon Allowance (CCA) price.[34]

**Q. Does Staff have any concerns with the first step of PacifiCorp's calculation?**

A. Yes. Staff has two concerns relating to PacifiCorp's assumed compliance costs. First, the Company does not reflect the lower compliance costs associated with California Carbon Offsets (CCO) in its CARB compliance cost. Second, the Company does not reflect the fact that Renewable Energy Credits (REC) from generation outside of California may be used to reduce its CARB compliance requirement.

[33] A naïve forecast uses the last period's actuals as the future period's forecast.

[34] California Carbon Allowances are issued and controlled by CARB and are bought and sold in quarterly auctions. Unlike Carbon Offsets, these allowances are not backed by carbon offset projects.

**Q. Please explain Staff's first concern with PacifiCorp's assumed compliance costs.**

A. Staff is aware that the Company has the right to combine the use of CCAs with up to 4 percent CCOs when fulfilling its compliance obligation with CARB.[35]

Aside from the environmental benefits of CCOs, these instruments are also cheaper. For instance, in past years PacifiCorp purchased CCOs at a cost of **[BEGIN CONFIDENTIAL]** [redacted] [36] **[END CONFIDENTIAL]** per unit. CCO futures are currently reported by ICE, albeit in a fairly illiquid market, with prices averaging $13.99, while ICE is also reporting comparable CCA futures with prices averaging $19.67.[37]

Staff noted that the Company has calculated its historic benefits using only CCA compliance costs, and learned from PacifiCorp that it has not engaged in any new agreements to purchase CCOs,[38] nor does it **[BEGIN CONFIDENTIAL]** [redacted].[39] **[END CONFIDENTIAL]**

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[35] Quantitative Usage Limits, as detailed by CARB on its website. https://ww2.arb.ca.gov/our-work/programs/compliance-offset-program/direct-environmental-benefits.

[36] Staff/102, Enright/25 - 27 (PacifiCorp's first Supplemental response to DR 31, and relevant attachment (confidential)).

[37] CCO futures with delivery months in 2021, representing a CCO purchased now and received in 2021. ICE "end of day" reports from May 27, 2021, in Staff/103, Enright/1 - 2.

[38] Staff/102, Enright/38 (PacifiCorp's response to DR 131).

[39] Based on discussions with PacifiCorp related to a discovery phone call on May 24, 2021.

**Q. What is Staff's position on the Company's use of CCOs for CARB compliance?**

A. Staff believes that a competitive business would strive to meet its compliance obligations in the most cost-effective way. An example of this is Portland General Electric (PGE), which maximizes GHG benefits to customers by including forecasted compliance with CCOs in its EIM benefit forecast.[40]

Considering the 2022 TAM in isolation, Staff estimates the value of using CCOs for compliance as **[BEGIN CONFIDENTIAL]** [redacted].[41] **[END CONFIDENTIAL]** Staff does not believe that this value is significant enough to warrant an adjustment at this time; however, Staff would like to make the utility aware of its expectation that costs to customers should be minimized.

Staff will continue to monitor this issue in future TAM filings, and may recommend an adjustment on this issue in the future if PacifiCorp has not pursued opportunities for low-cost compliance with CARB.

**Q. Please explain Staff's second concern with PacifiCorp's assumed compliance costs.**

A. Staff is aware that the Company has the right to retire RECs from power generated outside California (which was not directly delivered to California), in order to reduce its compliance obligation with CARB.[42]

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[40] UE 391 - PGE/100, Vhora-Outama-Batzler/30, lines 19 – 20.

[41] Staff/102, Enright/15 (attachment to PacifiCorp's second supplemental response to Staff DR 26 (confidential)).

[42] "Requires CARB to account for imported electricity … through source-based emissions accounting based on the direct delivery of power. The RPS adjustment may result in a reduction to the compliance obligation when requirements of the RPS adjustment are met." https://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep-power/rps-adj-guidance.pdf.

The RECs must have been generated by facilities which have been approved by the California Energy Commission as meeting California RPS standards. Public records show that PacifiCorp currently has 1,922 MW of installed capacity approved for California RPS standards, located in seven states.[43]

**Q. Has PacifiCorp provided details of precisely what instruments it uses to meet its CARB compliance requirements?**

A. No. In spite of multiple rounds of discovery and engagement with the Company, both in this filing[44] and the previous two years' TAM filings,[45,46] the Company has not produced the details of its CARB compliance that was requested by Staff.

Nevertheless, Staff has consulted the Annual Summary of GHG Mandatory Reporting released to the public by CARB for calendar years 2018 and 2019, and discovered that PacifiCorp reported zero "Non-Covered Emissions" in each year.[47] This signals that PacifiCorp has not used RECs to reduce its compliance requirement with CARB in recent years.[48]

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43 Data downloaded from the California Energy Commission on June 6, 2021. Exhibit Staff/104, Enright/1 - 2.

44 Staff/102, Enright/22 - 31 (PacifiCorp's first, first revised, first supplemental, and second supplemental responses to Staff DR 31); Staff/102, Enright/35 (PacifiCorp's response to Staff DR 125).

45 UE - 356, Staff/300, Enright/10, lines 9 - 11.

46 UE - 375, Staff/200, Enright/36, lines 2 – 5.

47 Staff/104, Enright/3 - 4.

48 Staff's assessment is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** confidential information provided to Staff. Staff/102, Enright/34 (relevant attachments to PacifiCorp's response to Staff DR 124 (confidential)).

**Q. What does Staff consider to be the best avenue to resolve this issue?**

A. Staff recommends that the Commission require PacifiCorp to provide full details of its CARB compliance costs to Staff,[49] and explain its methodology for achieving low-cost CARB compliance to ensure maximum benefits to Oregon customers.

**Q. Please provide more detail on the second step, the naïve forecast of future GHG benefits.**

A. The Company forecasts that future GHG benefits will equal past GHG benefits. It applies a seasonal shape to its forecast, and applies a growth factor to reflect annual increases in the auction floor price of CCAs.

**Q. Does Staff have any concerns with the second step of PacifiCorp's calculation?**

A. Yes, Staff has three concerns. First, the growth factor has been incorrectly applied. Second, the Company is proposing to use a limited period of historic benefit data in preparing its forecast. Third, CCA price growth is applied only to GHG benefits from hydro generator units.

**Q. Please explain Staff's first concern regarding the incorrect application of the growth factor, and Staff's proposed resolution.**

A. The Company uses historical data from **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** to forecast 2022 GHG benefits.[50] Although no specific

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[49] This could be accomplished by sharing the standardized CARB "ONE – Reporting workbook for EPE Importers & Exporters" with Staff. This would be supported by comprehensive details of both the instruments used by PacifiCorp for CARB compliance, and the CARB compliance costs actually incurred by the Company, traced back to the totals shown on the aforementioned Form.

[50] Staff/102, Enright/18 (attachment to PacifiCorp's response to Staff DR 27 (confidential)).

model for GHG benefits has been agreed on for the TAM, logic would suggest the growth factor should be applied for two years, to model the effect of the two-year difference between calendar year 2020 and calendar year 2022. In this case however, the growth factor has been applied for **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]**

Staff has corrected this issue by applying the growth factor for two years.[51] Correcting this error increases total-Company GHG benefits by **[BEGIN CONFIDENTIAL]** [redacted].[52] **[END CONFIDENTIAL]**

**Q. Does Staff have any other observations to share before proceeding?**

A. Staff notes that on May 25, 2021, the Company submitted correspondence in this case including the following statement:

> The historical GHG benefits related to EIM participation were overstated as a result of having cost components excluded in the benefit calculation. As the GHG benefit forecast is based on historical actuals, this caused an overstatement of the EIM forecast in the Company's direct filing. This will increase net power costs by $381,982 on a total-company basis.[53]

The Company did not file work papers to support its declaration.[54] In spite of this, Staff has made every effort possible to include up to date data in

[51] Staff has also calculated the growth factor on a monthly basis, rather than a yearly basis, to allow for appropriate growth factors to be applied to historic data from 2021 as it becomes available.
[52] Calculation assumes no change to underlying data used in PacifiCorp's initial filing, to allow for a like-for-like assessment.
[53] "Pacific Power's List of Corrections or Omissions," filed by PacifiCorp on May 25, 2021.
[54] The Company's correspondence was filed two weeks prior to the publication date of Opening Testimony, rendering it impossible for Staff or parties to conduct discovery on the three issues that were raised prior to Opening Testimony. Staff has nevertheless submitted discovery to request

its calculations, by updating each adjustment with data from DR responses received from the Company on May 27, 2021.[55]

To better represent the effect of adjustments, from this point on, Staff will present the effect of proposed adjustments compared with an estimated new GHG benefit forecast of **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]** This value represents Staff's estimate of the GHG benefit included in the initial filing, updated historic data through April 2021, the reported $381,982 reduction to GHG benefits, and the correction to the growth factor explained above.

**Q. Please explain Staff's second concern regarding its use of a limited period of historic benefit data.**

A. The Company's model is using only 12 months of historic data to inform its GHG benefit forecast. Staff's concern is that using such an unnecessarily short period of historic data is neither beneficial nor necessary, given that historic data is available for several years.

**Q. Is the Company's approach consistent with how TAM forecasts are usually derived?**

A. No. Throughout the TAM, forecasts using 48 months of historic data are considered the norm. For example, 48 months of historic data are used to forecast generation from Qualifying Facilities; 48 months of historic data are

that PacifiCorp's revised work papers be made available. Staff/102, Enright/43 - 44 (Staff DR 175, with response due June 9, 2021).

[55] Staff/102, Enright/15 (attachment to PacifiCorp's second supplemental response to Staff DR 26 (confidential)).

used to the DA-RT adjustment; and 48 months of historic data are used to forecast plant availability.

**Q. What approach has been taken in the past when four years of historic data is not available, or a shift in the market has occurred to make historic data less relevant?**

A. In the past, the available relevant data has been used. For example, the Commission directed the Company to use only the historic data from post-EIM years in its calculation of the DA-RT adjustment (rather than 48 months of historic data as it had proposed).[56] This was in response to concerns that Company's entrance into the EIM market represented a shift in its balancing costs, and PacifiCorp's concerns that "use of only two years of historical data runs the risk of creating a non-normalized result."[57] Over time, as more historic data became available, PacifiCorp adjusted the DA-RT calculation to include 48 months of historical data.

**Q. What historical dataset is it appropriate to use in this instance?**

A. Staff believes that a dataset beginning in December 2018, and including the most recently available data up to a maximum of 48 months, is most appropriate.

**Q. Why choose December 2018 as a starting point?**

A. Staff's recommendation is informed by representations made by PacifiCorp in its two most recent TAM filings.

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[56] UE 323 - Order No. 17-444 at 5 – 9 (Nov. 1. 2017).
[57] Id at 7.

In the 2020 TAM filing, the Company advocated for using data from the period beginning December 2018, corresponding with a shift in GHG benefits at that time, resulting from a change to CAISO's market policy.[58] The appropriateness of using December 2018 as a starting point for historical data was again stressed by the Company both in testimony[59] and in discovery[60] in the 2021 TAM filing.

**Q. What is Staff's assessment of the Company's approach to estimating future GHG benefits?**

A. Not only does the Company's proposal to use twelve months of historic data go against logic when a larger portion of data is available, but it goes against precedent and is inconsistent with the Company's approach with devising forecasts to date.

Staff's adjustment results in a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in NPC on a system-wide basis.

**Q. Staff voiced a third concern with the Company's forecast, relating to CCA price growth. Please explain this.**

A. In the 2021 TAM (UE 375), Staff argued that guaranteed increases in CCA prices[61,62] should be reflected in the GHG benefit forecast.[63] Although the

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[58] UE 356 - PAC/500, Brown/3, line 2 – 3 (2019 TAM filing).
[59] UE 375 - PAC/200, Mitchell/18 – 19 (2020 TAM filing).
[60] UE 375 - Staff/204, Enright/17.
[61] 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.
[62] Auction reserve prices are increased annually by five percent plus the rate of inflation, in accordance with 95911(c)(3) of the California Regulation.
[63] In Docket No. UE 375, Staff argued that because GHG benefits are driven by CCA prices, the GHG benefit forecast should be adjusted to reflect this predictable increase in CCA prices. UE 375 - Staff/200, Enright/41 - 42, lines 17 – 19 and 1 - 14.

Company indicates that it has adopted Staff's proposal from the 2021 TAM in this case,[64] it has in fact added an adjustment for growth to hydro GHG benefits only.

One might assume that because thermal generation has an associated compliance cost, an adjustment for CCA price increases is not necessary. However, as outlined earlier in this section, GHG benefits from thermal generator units exceed the associated compliance costs for thermal units at a ratio of **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]** Confidential Figure 6 shows that on average, GHG compliance costs for thermal units represent just **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** percent of overall thermal GHG revenue.

**[BEGIN CONFIDENTIAL]**

[redacted][65]

*Figure 6 – Confidential Thermal GHG Revenue vs Compliance Cost*

**[END CONFIDENTIAL]**

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[64] Staff/102, Enright/18 (PacifiCorp's response to Staff DR 27).
[65] Staff/102, Enright/15 (attachment to PacifiCorp's second supplemental response to Staff DR 26 (confidential)).

**Q. Is there a direct link between CCA prices and GHG benefits from thermal generator units?**

A. Yes, there is a direct link between CCA prices and GHG benefits to thermal units, this direct link exists because:

GHG prices are set by the GHG bid submitted by the marginal generator at each price node. PacifiCorp uses daily spot market values for CCAs as a direct input to its GHG bid. This is demonstrated in confidential Figure 7 below.

**[BEGIN CONFIDENTIAL]**

[redacted]

*Figure 7 – Confidential Formula to Create GHG bids in EIM* [66]

**[END CONFIDENTIAL]**

As CCA prices increase, PacifiCorp's GHG bids increase. As GHG bids increase, the marginal GHG price increases, and PacifiCorp receives a greater GHG revenue than before.

**Q. Is there also a direct link between CCA prices and PacifiCorp's compliance costs?**

A. Yes, there is a direct link between CCA prices and PacifiCorp's compliance costs. This direct link exists because PacifiCorp's GHG bid, referencing CCA prices, is direct input in PacifiCorp's GHG compliance cost calculation. This is

[66] For reference, this formula including units of measurement is **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]** Staff/102, Enright/19 (PacifiCorp's response to Staff DR 30 (confidential)).

demonstrated in Figure 8 below. Essentially, as CCA prices increase, PacifiCorp's GHG compliance cost increases.

$$\underset{\text{Sum all generators}}{\sum}\left(\text{Quantity MWh from PacifiCorp to CAISO} \times \text{EIM GHG bid prices}\right) = \text{GHG Compliance Cost}$$

*Figure 8 - Formula calculate GHG compliance cost for EIM transactions*

**Q. Is there a simple solution to ensure CCA price growth is correctly reflected in GHG benefits from thermal generator units?**

A. Yes. The simplest way to achieve this is to apply the CCA growth factor to both GHG benefits from thermal generator units, and their associated compliance costs. Staff advocates for this approach.

**Q. What is Staff's recommendation on the issue of CCA price growth?**

A. Staff recommends an adjustment to the forecast to reflect CCA price growth for GHG benefits arising all generation sources. Staff's adjustment will result in a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in NPC on a system-wide basis.

**Q. Please summarize Staff's recommendations regarding the GHG benefit forecast.**

A. Staff has made three recommendations.

First, Staff recommends a correction to the growth factor applied in the model. Correcting this error results in a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** decrease in NPC on a system-wide basis, or approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in GHG benefits attributed to Oregon customers.

Second, Staff recommends using the period since December 2018 as the basis for the GHG benefits forecast, gradually increasing the historic period used up to a maximum of 48 months as sufficient data becomes available. This adjustment results in a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** decrease in NPC on a system-wide basis, or approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in GHG benefits attributed to Oregon customers.

Third, Staff recommends that the CCA growth factor be applied not only to GHG benefits from hydro units, but also to the GHG benefits and GHG compliance costs of thermal units. This adjustment results in a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in NPC on a system-wide basis, or approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in GHG benefits attributed to Oregon customers.

The combined effect of Staff's four adjustments is a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in NPC on a system-wide basis, or approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in GHG benefits attributed to Oregon customers.[67]

[67] The combined effect of Staff's three adjustments is greater than the sum of these adjustments, due to the application of a growth factor to GHG revenue and compliance costs for thermal generation outside 12 month window that PacifiCorp has applied.

## ISSUE 1, PART 3 - FLEX RESERVE TRANSFER BENEFITS

**Q. Please describe how the Company benefits from flexible transfers in EIM.**

A. The enormous diversity of loads and variability of resources in EIM allow the Company to save money by holding lower reserves than it otherwise would require.

In addition to reducing its reserve requirement, the Company earns flexible reserves revenue for reserves provided.[68]

**Q. How has the Company forecasted the benefits of it holding lower reserves as a result of its EIM participation?**

A. The Company accounts for this through a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** reduction to its system-wide reserve requirement in GRID. The reduction reflects the average reduction in the reserves it would be required to hold alone, versus the reserves it is required to hold when participating in the EIM. This methodology is consistent with the methodology used in the 2021 forecast, and Company intends to update its calculation along with the scheduled update to this filing.[69]

[68] When a BAA exports flexible ramping services it receives compensation from other BAAs, and when the BAA imports flexible ramping services, it pays other BAAs. See CAISO's EIM benefit methodology, accessible at: www.westerneim.com/Documents/EIM_BenefitMethodology.pdf.

[69] Staff/102, Enright/2 - 4 (PacifiCorp's first response to Staff DR 19).

**Q. How has the Company forecasted the benefits it receives in the form of reserve payments received from EIM?**

A. The Company has not forecasted this specific benefit in the 2022 TAM, in spite of its agreement to include a $1,126 benefit[70] attributed to "flex transfer benefits" in the 2021 TAM in response to testimony from Staff on this matter.[71]

In spite of numerous discovery requests in this case,[72] and PacifiCorp's assurances in the stipulation settling the previous TAM to make this CAISO data available to Staff,[73] PacifiCorp has not provided equivalent data for the 2022 TAM, stating summarily that "as the process of assembling these values is onerous and financial impact is negligible".[74]

**Q. Does Staff have continued with the Company's approach?**

A. No. Staff is satisfied with the Company's approach in calculating a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** reduction to its system-wide reserve requirement in this case.

Although Staff has been unable to audit the value of the flex reserve benefits accruing to PacifiCorp, Staff does not intend to pursue this matter further in this case. Staff's approach reflects the small value of the flex transfer benefit reported by PacifiCorp, and the fact that in recent years PacifiCorp's measurement of EIM historic benefits has trended closely against CAISO's

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[70] UE 375 – Stipulation at 8; UE 375 – Stipulating Parties/100, Webb, Gibbens, Jenks, Higgins, Kaufman, Burgess, Reed, Dickman/16.
[71] UE 375 - Staff/200, Enright/44 – 45.
[72] Staff/102, Enright/2 - 4 and Staff/102, Enright/39 - 40 (PacifiCorp's first response to Staff DR 19 and PacifiCorp's response to DR 150).
[73] UE 375 – Stipulation at 19 (c); UE 375 – Stipulating Parties/100, Webb, Gibbens, Jenks, Higgins, Kaufman, Burgess, Reed, Dickman/16.
[74] Staff/102, Enright/39 - 40 (PacifiCorp's response to Staff DR 150).

measurement of the same.[75] PacifiCorp's measurement of historic EIM benefits is picked up as a driver of EIM energy benefits, as discussed in Staff/800, Issue 1.

**[BEGIN CONFIDENTIAL]**

[redacted][76]

*Figure 9 - Confidential CAISO's vs PacifiCorp's calculation of EIM benefits*

**[END CONFIDENTIAL]**

## ISSUE 1, PART 4 - EIM COSTS

**Q. Are fixed and variable EIM O&M costs being recovered in this filing?**

A. EIM Grid Management Charges (GMC) are variable costs which are recovered in the TAM. Staff audited the Company's past GMCs, and its forecast of GMCs for 2022, and has found no issues with the data. Staff notes that the forecast is based on actual GMCs incurred in the period July 2019 to June 2020, and is consistent with the approach taken in the 2021 TAM filing.

[75] CAISO's methodology for tracking EIM benefits differs from the Company's. CAISO uses resource level imbalance energy, EIM prices and bids to calculate transfer values, associated costs, and avoided costs and intra-regional benefits. PacifiCorp's calculation is similar to CAISO's, but uses balancing authority area (BAA) level EIM transfer volumes, EIM prices, and a BAA level resource stack to determine the associated costs or avoided costs.

[76] Staff/102, Enright/1 (relevant attachments to PacifiCorp's response to Staff DR 13, parts a - d (confidential)).

Fixed EIM costs are no longer being recovered in the TAM.[77] This change has occurred in line with the incorporation of fixed EIM costs into base rates via the Company's general rate case, Docket No. UE 374.

Separate to EIM fees, this filing includes a $8.4 million annual service fee paid to CAISO to perform a nodal pricing model service for PacifiCorp, as discussed in Staff/900, Issue 3.

**Q. Does Staff have any recommendations regarding the recovery of EIM costs in this filing?**

A. No.

## ISSUE 1, PART 5 – INTERPLAY BETWEEN FORECASTING BALANCING TRANSACTIONS IN GRID, AND FORECASTING EIM BENEFITS

**Q. What is the purpose of this section?**

A. This section of testimony is responsive to Issue 4 of the Commission's May 21, 2021 Issues List in this case, related to EIM import and export volumes and system balancing trades.

**Q. What relationship exists between the GRID model, and the Company's proposed models for forecasting EIM benefits?**

A. The GRID model is completely independent of the EIM benefits forecasting models, with the exception of the flex reserve transfer benefit.

Flex reserve benefits are calculated based on the historic average reduction in the reserves PacifiCorp is required to hold while participating in

[77] In prior filings, fixed EIM costs were recovered in the TAM in accordance with Order No. 18-421.

EIM (measured in MWh) compared to the counterfactual situation without participation in EIM. This figure, a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** reduction in reserves, is fed into the GRID model, allowing GRID to simulate the operation of PacifiCorp's system, while accounting for its reduced reserve requirement due to EIM.

The energy transfer and GHG benefit models on the other hand, operate independent of GRID, and GRID operated independent of the models.

GRID simulates the operation of the Company's power system on an hourly basis based on the Company's generator unit availability, forecasted renewable generation, forecasted market prices, etc. It does not account for the existence of the EIM market for trades.

PacifiCorp's energy transfer benefits model forecasts energy benefits based on the relationship between past benefits (measured in dollars) and various market drivers. Again, this model is not informed by GRID, nor does it inform GRID.

Similarly, PacifiCorp's GHG benefits model forecasts GHG benefits based on a trend of historic benefits (measured in dollars). It is not informed by GRID, nor does it inform GRID.

**Q. Is it true that the volume (MWh) of EIM transactions is not modeled in the TAM, just the benefits ($)?**

A. Partially. PacifiCorp's energy transfer benefits and GHG benefits are measured in dollars. PacifiCorp's Flex reserve benefits on the other hand, are measured in MWh.

**Q. How have Oregon's other IOUs approached their forecast of EIM benefits?**

A. Each of Oregon's IOUs forecast their EIM benefits using models. In each case, the models operate outside of the IOUs system optimization model, meaning that EIM opportunities to do not inform the system optimization models.

Idaho Power's approach is to forecast its total EIM benefit as a function of past benefits,[78] separate to its AURORA model. Although the output of the EIM benefit forecast is measured in dollars rather than MWh, Staff expects that the model may be adjusted to report the approximate MWh value of the forecasted transactions.

In the case of PGE, energy transfer benefits are also forecasted separately to the MONET system optimization model. However, the forecast directly based on the outputs of the MONET model, considering the marginal generation cost of PGE's fleet, forecasted EIM market prices, forecasted Mid-C prices, and historic trading levels.[79] This model forecasts MWh trades in EIM and the value with these trades is the energy transfer benefit.

Similar to PacifiCorp, PGE's GHG benefits are forecasted based on historic GHG revenue, reduced by historic CARB compliance costs.[80] In contrast to PacifiCorp, PGE forecasts flex reserve payments as a function of its historic flexible ramping product award, expressed as a dollar value.[81]

[78] UE 384 - Idaho Power/100, Blackwell/15 - 19.
[79] UE - 391, PGE/100, Vhora-Outama-Batzler/25 - 29.
[80] UE - 391, PGE/100, Vhora-Outama-Batzler/30 - 31.
[81] UE - 391, PGE/100, Vhora-Outama-Batzler/29.

**Q. What relationship exists between forecasted balancing trades, actual balancing trades, and EIM trades?**

A. PacifiCorp provided historic data on forecasted system balancing transactions and actual balancing trades inside of EIM in response to Staff discovery.[82] Staff has concerns regarding the reliability of the data provided as it does not match data provided by the Company in other power cost filings, and as such has not presented the data in testimony.

Staff is interested in hearing from the Company in reply testimony about what perceived relationship may exist between these categories of trades, assuming that reliable and transparent data is provided in support of any assertions the Company makes.

Further, Staff looks forward to suggestions from PacifiCorp in reply testimony, regarding its proposals for appropriately capturing changing trends and dispatch from the EIM in a TAM forecast.

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

A. Yes.

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[82] Staff/102, Enright/42 (attachment to PacifiCorp's response to Staff DR 174 (confidential)).

CASE: UE 390
WITNESS: MOYA ENRIGHT

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 101

# Witness Qualifications Statement

# June 9, 2021

**WITNESS QUALIFICATIONS STATEMENT**

| | |
|---|---|
| NAME: | Moya Enright |
| EMPLOYER: | Public Utility Commission of Oregon |
| TITLE: | Senior Economist<br>Energy Rates Finance and Audit Division |
| ADDRESS: | 201 High Street SE. Suite 100<br>Salem, OR. 97301 |
| EDUCATION: | Energy Risk Professional Certification (part-qualified). Global Association of Risk Professionals.<br><br>M.Sc. Political Science, 2015.<br>University of Amsterdam.<br><br>M.Sc. Investment, Treasury and Banking, 2011.<br>Dublin City University.<br><br>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.<br><br>Energy Trader for Meridian Energy from 2015 to 2019. Meridian Energy is a power generator and retailer operating both in New Zealand and Australia.<br><br>Trading and Operations Analyst at Tynagh Energy from 2011 to 2013. Tynagh Energy is an independent power producer operating in the Republic of Ireland.<br><br>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.<br><br>Accounts Assistant roles from 2004 to 2008, including Audit Intern at KPMG in Northern Ireland. |

CASE: UE 390
WITNESS: MOYA ENRIGHT

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 102

# Confidential Exhibits in Support Of Opening Testimony

**June 9, 2021**

# Confidential Staff Exhibits

## “Relevant attachments to PacifiCorp’s response to Staff DR 13, parts a - d”

## are

## filed in electronic format

UE 390 / PacifiCorp
May 3, 2021
OPUC Data Request 19

**OPUC Data Request 19**

**EIM -** Regarding the Company's modeling of the reserve benefits of EIM participation:

(a) Please provide a narrative explanation of how the Company accounts for the reserve benefits of EIM participation.

(b) Please quantify the reserve benefit received by the Company in both MW and $ values in electronic workbook format, with all cells and formulas intact.

(c) Please provide all work papers and input data used by the Company to calculate EIM reserve benefits in electronic workbook format, with all cells and formulas intact. This is an ongoing request for updated work papers to be provided in-line with the Company's update filings.

(d) Does the Company intend to update its calculation of EIM reserve benefits as part of the scheduled updates to the 2022 TAM filing?

(e) If the methodology described in response to section "a" differs from that used in the 2021 TAM, please provide an explanation of all changes, with specific reference to work papers and specific cells within.

(f) Please provide the results and calculation from the Company's 2019 Integrated Resource Plan's (IRP) flexible reserve study, which measured the Company's EIM reserve benefit based on the diversified footprint of the energy imbalance market. Please include updated data to include the most recent month, providing the data in electronic workbook format, with all cells and formulas intact. This is an ongoing request.

(g) If the Company intends to use a different methodology than the methodology referenced in section "f" in its 2021 IRP flexible reserve study, please provide an explanation of any changes, with specific reference to work papers and specific cells within. Please provide an update to this response if the Company's answer changes during the duration of this proceeding.

**Response to OPUC Data Request 19**

(a) The Company's forecasted regulation reserve requirement is based on the uncertainty associated with loads and resources in PacifiCorp's balancing authority areas (BAA), and PacifiCorp's stand-alone reliability obligations, but includes a credit based on the diversity benefits attributed to PacifiCorp East (PACE) and PacifiCorp West (PACW) as part of its energy imbalance market (EIM) participation. Please refer to PacifiCorp's 2019 Integrated

Resource Plan (IRP), specifically Volume II, Appendix F (Flexible Reserve Study) (FRS) for more detail. PacifiCorp's IRP is publicly available, and can be accessed by utilizing the following website link:

Integrated Resource Plan (pacificorp.com)

(b) The Company has not quantified the dollar values or megawatt (MW) amounts associated with the EIM diversity benefit. The reduced MW requirements are modeled, and the associated dollar values are embedded in the overall net power costs (NPC) results.

(c) For the Company's initial / direct testimony filing, please refer to the Company's response to subpart (b) above. The Company will supplement the response to this request, if applicable, during this proceeding.

(d) Yes.

(e) Not applicable. There is no change to the methodology.

(f) Please refer to the confidential and non-confidential work papers on the data disks that accompanied PacifiCorp's 2019 IRP, specifically the confidential and non-confidential work papers supporting Appendix F (Flexible Reserve Study). For ease of reference, the Company is providing copies of those work papers herewith as Confidential Attachment OPUC 19-1 and Attachment OPUC 19-2. In addition, please refer to Confidential Attachment OPUC 19-3 which replicates Table F.9 of PacifiCorp's 2019 IRP, and Confidential Attachment OPUC 19-4, with updates Attachment OPUC 19-3 with EIM diversity benefits data through April 21, 2021.

(g) EIM reserve benefits are expected to be incorporated in the Company's 2021 IRP Flexible Reserve Study (FRS) using the same general methods and source data as the 2019 IRP. Because additional historical data is available, the historical EIM diversity benefits in the 2021 IRP are being calculated by season as well as by hour. In addition, because EIM reserve benefits are allocated proportionate with each BAA's stand-alone requirements, if the Company's regulation reserve requirements increase, its share of the EIM reserve benefits would also increase. Therefore, in the 2021 IRP, EIM diversity benefits are assumed to scale with changes in the Company's portfolio, as this would increase the Company's regulation reserve requirements. The Company has not finalized its work papers that will support the 2021 IRP FRS, but will supplement this response when those work papers become available.

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Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

UE 390 / PacifiCorp
May 27, 2021
OPUC Data Request 19 – 1st Supplemental

**OPUC Data Request 19**

**EIM -** Regarding the Company's modeling of the reserve benefits of EIM participation:

(a) Please provide a narrative explanation of how the Company accounts for the reserve benefits of EIM participation.

(b) Please quantify the reserve benefit received by the Company in both MW and $ values in electronic workbook format, with all cells and formulas intact.

(c) Please provide all work papers and input data used by the Company to calculate EIM reserve benefits in electronic workbook format, with all cells and formulas intact. This is an ongoing request for updated work papers to be provided in-line with the Company's update filings.

(d) Does the Company intend to update its calculation of EIM reserve benefits as part of the scheduled updates to the 2022 TAM filing?

(e) If the methodology described in response to section "a" differs from that used in the 2021 TAM, please provide an explanation of all changes, with specific reference to work papers and specific cells within.

(f) Please provide the results and calculation from the Company's 2019 Integrated Resource Plan's (IRP) flexible reserve study, which measured the Company's EIM reserve benefit based on the diversified footprint of the energy imbalance market. Please include updated data to include the most recent month, providing the data in electronic workbook format, with all cells and formulas intact. This is an ongoing request.

(g) If the Company intends to use a different methodology than the methodology referenced in section "f" in its 2021 IRP flexible reserve study, please provide an explanation of any changes, with specific reference to work papers and specific cells within. Please provide an update to this response if the Company's answer changes during the duration of this proceeding.

**1st Supplemental Response to OPUC Data Request 19**

In further support of the Company's response to OPUC Data Request 19, dated May 3, 2021, the Company provides the following additional information responsive to subpart (b):

(b) Please refer to Confidential Attachment OPUC 19 1st Supplemental. Note: the energy imbalance market (EIM) benefits are located on tab "EIM," cell I1.

This is the benefit, in megawatts (MW) on an average basis, across both sides of the system combined.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

# Confidential Staff Exhibit

# “Attachment to PacifiCorp’s first supplemental response to Staff DR 19”

# is

# filed in electronic format

UE 390 / PacifiCorp
May 4, 2021
OPUC Data Request 26

**OPUC Data Request 26**

**Energy Imbalance Market (EIM)** - Regarding the Company's calculation of realized EIM GHG benefits:

(a) Please provide a step-by-step explanation of how the Company calculates its realized EIM GHG benefits. Please include details of the formulas and inputs used, providing specific references to the workbooks provided in response to sections "b" and "c".

(b) Please provide the Company's calculation of its realized EIM benefits for each month since joining EIM. Please include all input data, and where input data has been calculated separately, provide a narrative description of how the input was calculated, including details of formulas and inputs used, and all underlying data. Please provide the requested data in electronic workbook format, with all cells and formulas intact.

(c) Did the Company calculate its realized EIM GHG benefits using the same methodology as in Docket No. UE 375? If no, please provide a narrative description of the changes including references to the work papers, specific cells, and formulas in which these changes can be identified. Please provide the requested data in electronic workbook format, with all cells and formulas intact.

**Response to OPUC Data Request 26**

(a) The California Independent System Operator's (CAISO) calculation of PacifiCorp's energy imbalance market (EIM) greenhouse gas (GHG) benefits is performed and maintained by the CAISO for the CAISO. PacifiCorp has no archive of the CAISO calculated EIM benefits or the breakdown of the GHG benefits. The total EIM benefits calculated by the CAISO are publicly available in quarterly documents and can be accessed by utilizing the following website link:

https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx

(b) The CAISO's calculation of PacifiCorp's EIM benefits is performed and maintained by the CAISO for the CAISO. PacifiCorp has no archive of the CAISO calculated EIM benefits. The total EIM benefits calculated by the CAISO are publicly available in quarterly documents and can be accessed by utilizing the following website link:

https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx

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(c) Yes.

UE 390 / PacifiCorp
May 14, 2021
OPUC Data Request 26 – 1st Supplemental

**OPUC Data Request 26**

**Energy Imbalance Market (EIM)** - Regarding the Company's calculation of realized EIM GHG benefits:

(a) Please provide a step-by-step explanation of how the Company calculates its realized EIM GHG benefits. Please include details of the formulas and inputs used, providing specific references to the workbooks provided in response to sections "b" and "c".

(b) Please provide the Company's calculation of its realized EIM benefits for each month since joining EIM. Please include all input data, and where input data has been calculated separately, provide a narrative description of how the input was calculated, including details of formulas and inputs used, and all underlying data. Please provide the requested data in electronic workbook format, with all cells and formulas intact.

(c) Did the Company calculate its realized EIM GHG benefits using the same methodology as in Docket No. UE 375? If no, please provide a narrative description of the changes including references to the work papers, specific cells, and formulas in which these changes can be identified. Please provide the requested data in electronic workbook format, with all cells and formulas intact.

**1st Supplemental Response to OPUC Data Request 26**

In further support of to the Company's response to OPUC Data Request 26, dated May 4, 2021, the Company provides the following additional information specific to the Company's calculation of energy imbalance market (EIM) greenhouse gas (GHG) benefits:

(a) PacifiCorp extracts the five-minute interval Imbalance Energy Export Allocation (IEEA) market award information from the California Independent System Operator (CAISO), by resource. These awards determine how many megawatt-hours (MWh) have been exported from PacifiCorp to CAISO and therefore, which PacifiCorp exports are subject to greenhouse gas (GHG) penalties. The IEEA market awards are then summarized across an individual day, divided by 12 and multiplied by the EIM GHG bid prices to calculate daily totals of EIM GHG cost by resource. Those values are then aggregated across all participating thermal resources and provided as the GHG cost component of the GHG benefits into the daily GHG benefit values.

Please refer to Confidential Attachment OPUC 26-1 1st Supplemental, which, as an example, uses data for March 1, 2021 through March 3, 2021. Please also refer to the descriptions of the data file provided below:

The "3.1-3.3 GHG Cost Reports" are raw data files that summarize the Market Awards by resource across all five-minute intervals. Columns B, S and V from each of the raw data files is stacked in tab "Stacked Cost Data." Tab "Cost Pivot" uses a pivot table referencing the data in "Stacked Cost Data." Tab "Cost Pivot" provides a pivot table that shows the summation of the IEEA values by resource (MWh) by day. This calculation divides the sum of total MWh generated for each resource by 12. This is done to correct that the underlying data indicates the MWh rate of production, but only across five minutes of actual generation. Tab "Cost Calc" references the "Cost Pivot" table's volumes and multiples by the GHG bid price to produce the GHG cost by resource. At the bottom of the "Cost Calc" table, the daily totals are summarized. These values are transposed onto tab "GHG Benefit Summary" to calculate the GHG benefit summary.

Tab "Revenue Report" provides another raw data file that summarizes the CAISO Charge Code 491 statement details by day. The "Current Amount" column corresponds to the cost that CAISO incurs for Charge Code 491 settlement with PacifiCorp. This is a positive revenue value for PacifiCorp, therefore the sign is flipped when that column is added to the "GHG Benefit Summary." On tab "GHG Benefit Summary," GHG benefits are simply the GHG revenues minus the GHG costs.

(b) Please refer to Confidential Attachment OPUC 26-2 1st Supplemental, which provides the Company's calculation of its realized EIM benefits for each month, since January 2017 through January 2021. The monthly data in this file summarizes the daily GHG totals outlined in the methodology described in the Company's response to subpart (a) above.

Note: in the preparation of the Company's response to this data request, it was determined that the calculation of the Company's GHG benefits excluded three thermal resources starting May 5, 2020. This has led to understated GHG costs and in turn, overstated GHG benefits by $490,560, on a total company basis, between May 2020 and January 2021. The values presented in Confidential Attachment OPUC 26-2 1st Supplemental contain values that have been corrected to reflect the three omitted resources.

(c) Yes.

UE 390 / PacifiCorp
May 14, 2021
OPUC Data Request 26 – 1st Supplemental

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

UE 390 / PacifiCorp
May 27, 2021
OPUC Data Request 26 – 2nd Supplemental

**OPUC Data Request 26**

**Energy Imbalance Market (EIM)** - Regarding the Company's calculation of realized EIM GHG benefits:

(a) Please provide a step-by-step explanation of how the Company calculates its realized EIM GHG benefits. Please include details of the formulas and inputs used, providing specific references to the workbooks provided in response to sections "b" and "c".

(b) Please provide the Company's calculation of its realized EIM benefits for each month since joining EIM. Please include all input data, and where input data has been calculated separately, provide a narrative description of how the input was calculated, including details of formulas and inputs used, and all underlying data. Please provide the requested data in electronic workbook format, with all cells and formulas intact.

(c) Did the Company calculate its realized EIM GHG benefits using the same methodology as in Docket No. UE 375? If no, please provide a narrative description of the changes including references to the work papers, specific cells, and formulas in which these changes can be identified. Please provide the requested data in electronic workbook format, with all cells and formulas intact.

**2nd Supplemental Response to OPUC Data Request 26**

In further support of the Company's prior responses to OPUC Data Request 26, the Company provides the following additional information:

Please refer to Confidential Attachment OPUC 26 2nd Supplemental, which provides the results of PacifiCorp's daily energy imbalance market (EIM) greenhouse gas (GHG) benefits data from January 1, 2019 through April 30, 2021. The daily EIM GHG benefits are the difference between the GHG revenues and GHG costs.

The source of the GHG revenues is explained in the Company's description of the "Revenue Report" provided in the Company's 1st Supplemental response to OPUC Data Request 26 subpart (a). PacifiCorp does not perform any calculations on the GHG revenue, but records the GHG revenue information directly from California Independent System Operator (CAISO) Charge Code 491.

The process for assembling the GHG cost is explained in the Company's 1st Supplemental response to OPUC Data Request 26 subpart (a). However, further explanation and additional references are outlined below.

- The Imbalance Energy Export Allocation (IEEA) transfer data (megawatt-hours (MWh)) that is downloaded from CAISO to assemble the GHG costs outlined here is the same data that will be provided with the Company's response to OPUC Data Request 153, specifically Confidential Attachment OPUC 153-1. Note: the Company anticipates providing its response to OPUC Data Request 153 on or before June 2.

- PacifiCorp filters the IEEA transfer data by "IEEA" under "Product" and by "Market" under "Schedule_Type." Using a pivot table, the data on total MWh exported to CAISO can be summarized by resource by day.

- Using GHG bids, the total cost by resource is assembled by multiplying the GHG bid price by the total IEEA volumes exported to CAISO. These daily values are summed over all resources to create the daily GHG cost values.

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# Confidential Staff Exhibit

## “Attachment to PacifiCorp’s second supplemental response to Staff DR 26”

## is

## filed in electronic format

UE 390 / PacifiCorp
May 4, 2021
OPUC Data Request 27

**OPUC Data Request 27**

**Energy Imbalance Market (EIM)** - Regarding the Company's calculation of 2022 forecasted EIM GHG benefits:

(a) Please provide a step-by-step explanation of how the Company calculates its forecasted EIM GHG benefits. Include details of the formulas and inputs used, providing specific references to the workbooks provided in response to sections "b" and "c".

(b) Please provide the Company's calculation of its forecasted EIM benefits for each month in 2022. Please include all input data, and where input data has been calculated separately, provide a narrative description of how the input was calculated, including details of formulas and inputs used, and all underlying data. Please provide the requested data in electronic workbook format, with all cells and formulas intact.

(c) Did the Company calculate its forecasted EIM GHG benefits using the same methodology as in Docket No. UE 375? If no, please provide a narrative description of the changes including references to the work papers, specific cells, and formulas in which these changes can be identified. Please provide the requested data in electronic workbook format, with all cells and formulas intact.

(d) Please explain whether the Company's forecasted GHG benefit includes an adjustment for future increases in California Carbon Allowance (CCA) prices. Please include all supporting analysis in electronic spreadsheet format, with all formulas and cell references intact.

(e) If the Company intends to update its forecasted EIM GHG benefit in scheduled updates to this filing, please list each intended update to the forecast and the updated data intended to be included in in each.

**Response to OPUC Data Request 27**

(a) Please refer to Confidential Attachment OPUC 27, tab "GHG Benefits", cells F62 through F73. The sum of these values is the forecast for 2022, and is the amount included in the 2022 transition adjustment mechanism (TAM). In this work paper, tab "GHG Data", the annual forecast is seasonally shaped using the ratios in the cells L2 through L5. These ratios are derived from the seasonal shape of the actual energy imbalance market (EIM) greenhouse gas (GHG) benefits from February 2020 through January 2021 (cells E39 through E50). Those monthly totals are then split into a hydroelectric benefit forecast and thermal benefit forecast, with the hydroelectric benefits grown by inflation coupled with a California Carbon Allowance (CCA) growth rate assumption of 5 percent, as proposed by the Public Utility Commission of Oregon (OPUC) staff in Docket UE 375. Please refer to the opening testimony of OPUC staff witness, Moya Enright, specifically Exhibit 200 Enright/3 lines 14 through 16.

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

(c) Yes.

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

(e) The Company expects to update the forecast using newly available actual benefits and updated inflation in the July 2021 update filing, as well as the November 2021 indicative filing.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

# Confidential Staff Exhibit

# “Attachment to PacifiCorp’s response to Staff DR 27”

# is

# filed in electronic format

UE 390 / PacifiCorp
May 4, 2021
OPUC Data Request 30

**OPUC Data Request 30**

**Energy Imbalance Market (EIM)** – regarding GHG bidding in the EIM:

(a) Please provide the calculation used by the Company to create GHG bids for submission to CAISO in electronic spreadsheet format, with all formulas and cell references intact.

(b) Please provide a narrative description of how the Company prepares its EIM GHG bids, specifying what inputs are used in the calculation provided in response to section "a" the source of the inputs, and detail of intervals at which the input data is refreshed.

(c) Please provide the average GHG bid submitted to the EIM for each generator unit, for each month since joining EIM in electronic spreadsheet format, with all formulas and cell references intact.

(d) Please provide the average emission factor in MT/MWh for each of the Company's EIM participating generator units, for each month since joining EIM in electronic spreadsheet format, with all formulas and cell references intact.

(e) For all historic changes to the monthly average emission factors shown in response to section "d", please provide a narrative explanation of the reason for the change.

(f) Does the Company consider the actual purchase price of CCAs or CCOs at when bidding into EIM? Please provide a narrative response.

**Confidential Response to OPUC Data Request 30**

(a) Please refer to Confidential Attachment OPUC 30-1 which provides the calculations used by the Company to create greenhouse gas (GHG) bids for submission to California Independent System Operator (CAISO) in the energy imbalance market (EIM).

(b) Please refer to the two equations provided below which outline how PacifiCorp creates the EIM GHG bids:

**[CONFIDENTIAL BEGINS]**

[redacted]

[redacted]

**[CONFIDENTIAL ENDS]**

**Emission Rate**
**(metric tons per million British thermal Unit (mt/MMBtu)):**
The emission rate for each plant is calculated on a yearly basis by the California Air Resources Board (CARB).

**Average Heat Rate**
**(million British thermal units per megawatt-hour (MMBtu/MWh)):**
Calculated for each plant, the values are monitored and reviewed periodically.

**California Carbon Allowance (CCA)**
**(dollars per metric ton ($/mt)):**
Prior to December 17, 2020, PacifiCorp's traders would retrieve the value from the bi-lateral GHG market as posted on the IntercontinentalExchange (ICE) market. The GHG market value on ICE is somewhat range bound and had minor fluctuations in the price. The GHG value was periodically updated as prices changed. The **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]** value provided in Confidential Attachment OPUC 30-1 represents the GHG market value as quoted by ICE. This methodology was used up until December 17, 2020, at which point PacifiCorp stopped its practice of using the bi-lateral market GHG value published by ICE, and instead transitioned to retrieving the daily spot market values for GHG published daily by the CAISO.

(c) Please refer to Confidential Attachment OPUC 30-2 which provides an overview of the average GHG bids submitted to the EIM for each of PacifiCorp's generating units from December 2015 to December 2020.

(d) Please refer to Confidential Attachment OPUC 30-3 which includes EIM emission factors for 2014 through 2021. PacifiCorp uses annual emission factors that get updated in March or April for the previous calendar year generation. Monthly data is not available.

(e) Emission factors are changed yearly as calculated and provided by CARB according to section 95111(b)(2). These factors are updated by CARB in March or April of each year for the previous calendar year generation, at which time the Company updates accordingly for its EIM participating generating units.

(f) Yes, the Company considers the actual purchase price of CCAs when bidding into the EIM. An adder is included to each EIM participating generating unit bid to ensure that the Company is kept whole in recovering the cost of CCAs.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

UE 390 / PacifiCorp
May 4, 2021
OPUC Data Request 31

**OPUC Data Request 31**

**Energy Imbalance Market (EIM)** – With regard to the Company's purchase and sale of CCAs or CCOs:

(a) Please provide a narrative explanation of how PacifiCorp purchases or sells CCAs, including details of how the Company ensures that the most advantageous price is achieved. If the Company's response differs for any of the sub-categories listed in Staff Data Request (DR) 29 section "a", please provide a detailed response for each.

(b) Please provide a narrative explanation of how PacifiCorp purchases or sells CCOs, including detail of how the Company ensures that the most advantageous price is achieved. If the Company's response differs for any of the sub-categories listed in Staff DR 29 section "a", please provide a detailed response for each.

(c) Please provide all internal policies and procedures relating to the purchase or sale of CCAs or CCOs.

(d) Please separately list PacifiCorp's CCA and CCO purchases since January 1, 2014, including the total price, quantity of credits purchased, and credit price, in electronic spreadsheet format with all formulas and cell references intact.

(e) Please separately list PacifiCorp's CCA and CCO sales since January 1, 2014, including the total price, quantity of credits purchased, and credit price, in electronic spreadsheet format with all formulas and cell references intact.

(f) Please indicate the number of excess[1] CCAs and CCOs held by the Company on December 31, 2020.

(g) If PacifiCorp receives free or subsidized CCAs or CCOs, please provide a narrative explanation of the circumstances of this, including the source and intended purpose of the CCAs or CCOs, and how this relates to the Company's allowance allocation from CARB.

(h) If PacifiCorp receives free or subsidized CCAs or CCOs, please list the total quantity of CCAs of CCOs received in each month since January 1, 2014. Please provide this data in electronic spreadsheet format with all formulas and cell references intact, including commentary on the amount and value of all subsidies.

[1] "Excess" refers to CCAs or CCOs held in excess of the Company's compliance requirement for the period ending December 31, 2020.

UE 390 / PacifiCorp
May 4, 2021
OPUC Data Request 31

**Confidential Response to OPUC Data Request 31**

(a) Referencing OPUC Data Request 29, specifically subpart (a) categories i. through iii., for California Carbon Allowances (CCA) purchases, PacifiCorp purchases CCAs in the spot market using a voice broker. The Company uses the Intercontinental Exchange (ICE) for current market price awareness, to ensure the most advantageous price is achieved.

Referencing OPUC Data Request 29, subpart (a) category "iv," the CCAs for the Company retails sales in California, are purchased and sold through the California Air Resources Board (CARB) quarterly auctions. The Company is obligated under cap and trade regulations to sell its CARB allocated allowances at auction. **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]**. Historically, CARB auction prices have been generally consistent with or slightly below ICE market prices of the same period.

(b) The Company does not purchase carbon offsets.

(c) Please refer to Confidential Attachment OPUC 31-1 which provides a copy of PacifiCorp's most recent Energy Risk Management Policy, approved January 7, 2021, which addresses the purchase of greenhouse gas (GHG) allowances.

(d) Please refer to Confidential Attachment OPUC 31-2.

(e) There are no sales of CCA and California Carbon Offsets (CCO). CCAs and CCOs are surrendered or retired in the CARB's compliance instrument tracking system service (CITSS) by transferring from the "General Account" to "Compliance Account."

(f) Determination of excess allowances cannot be made at this time. The Company's compliance obligation through December 31, 2020 will be established following CARB reporting with audited results concluding in August 2021.

(g) The Company does not receive free or subsidized CCAs or CCOs.

(h) Please refer to the Company's response to subpart (g) above.

UE 390 / PacifiCorp
May 4, 2021
OPUC Data Request 31

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

UE 390 / PacifiCorp
May 14, 2021
OPUC Data Request 31 – 1st Supplemental

**OPUC Data Request 31**

**Energy Imbalance Market (EIM)** – With regard to the Company's purchase and sale of CCAs or CCOs:

(a) Please provide a narrative explanation of how PacifiCorp purchases or sells CCAs, including details of how the Company ensures that the most advantageous price is achieved. If the Company's response differs for any of the sub-categories listed in Staff Data Request (DR) 29 section "a", please provide a detailed response for each.

(b) Please provide a narrative explanation of how PacifiCorp purchases or sells CCOs, including detail of how the Company ensures that the most advantageous price is achieved. If the Company's response differs for any of the sub-categories listed in Staff DR 29 section "a", please provide a detailed response for each.

(c) Please provide all internal policies and procedures relating to the purchase or sale of CCAs or CCOs.

(d) Please separately list PacifiCorp's CCA and CCO purchases since January 1, 2014, including the total price, quantity of credits purchased, and credit price, in electronic spreadsheet format with all formulas and cell references intact.

(e) Please separately list PacifiCorp's CCA and CCO sales since January 1, 2014, including the total price, quantity of credits purchased, and credit price, in electronic spreadsheet format with all formulas and cell references intact.

(f) Please indicate the number of excess[1] CCAs and CCOs held by the Company on December 31, 2020.

(g) If PacifiCorp receives free or subsidized CCAs or CCOs, please provide a narrative explanation of the circumstances of this, including the source and intended purpose of the CCAs or CCOs, and how this relates to the Company's allowance allocation from CARB.

(h) If PacifiCorp receives free or subsidized CCAs or CCOs, please list the total quantity of CCAs of CCOs received in each month since January 1, 2014. Please provide this data in electronic spreadsheet format with all formulas and cell references intact, including commentary on the amount and value of all subsidies.

[1] "Excess" refers to CCAs or CCOs held in excess of the Company's compliance requirement for the period ending December 31, 2020.

UE 390 / PacifiCorp
May 14, 2021
OPUC Data Request 31 – 1st Supplemental

**1st Supplemental Confidential Response to OPUC Data Request 31**

In further support of the Company's response to OPUC Data Request 31, dated May 4, 2021, the Company provides the following additional information relevant to subparts (d) and (e):

(d) In addition to the Company's original response to subpart (d), and the Company's reference to Confidential Attachment OPUC 31-2, please also refer to the Company's response to OPUC Data Request 99 in docket UE 375 (2021 transition adjustment mechanism). For ease of reference, a copy is provided herewith as Confidential Attachment OPUC 31-1 1st Supplemental.

(e) Reiterating the Company's original response to subpart (e) that there are no sales of California Carbon Allowances (CCA) and California Carbon Offsets (CCO). CCAs and CCOs are surrendered or retired in the California Air Resources Board's (CARB) compliance instrument tracking system service (CITSS) by transferring from the "General Account" to "Compliance Account." The Company further explains that **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]**. Please refer to Confidential Attachment OPUC 31-2 1st Supplemental for CCAs consigned to auction since 2014.

With regard to the consignment process, the California greenhouse gas (GHG) cap-and-trade program under California's Global Warming Solutions Act (Assembly Bill (AB) 32) requires that each calendar year, **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]**.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

# Confidential Staff Exhibit

# “Relevant attachment to PacifiCorp’s first supplemental response to Staff DR 31”

# is

# filed in electronic format

UE 390 / PacifiCorp
May 21, 2021
OPUC Data Request 31 – 1st Revised

**OPUC Data Request 31**

**Energy Imbalance Market (EIM)** – With regard to the Company's purchase and sale of CCAs or CCOs:

(a) Please provide a narrative explanation of how PacifiCorp purchases or sells CCAs, including details of how the Company ensures that the most advantageous price is achieved. If the Company's response differs for any of the sub-categories listed in Staff Data Request (DR) 29 section "a", please provide a detailed response for each.

(b) Please provide a narrative explanation of how PacifiCorp purchases or sells CCOs, including detail of how the Company ensures that the most advantageous price is achieved. If the Company's response differs for any of the sub-categories listed in Staff DR 29 section "a", please provide a detailed response for each.

(c) Please provide all internal policies and procedures relating to the purchase or sale of CCAs or CCOs.

(d) Please separately list PacifiCorp's CCA and CCO purchases since January 1, 2014, including the total price, quantity of credits purchased, and credit price, in electronic spreadsheet format with all formulas and cell references intact.

(e) Please separately list PacifiCorp's CCA and CCO sales since January 1, 2014, including the total price, quantity of credits purchased, and credit price, in electronic spreadsheet format with all formulas and cell references intact.

(f) Please indicate the number of excess[1] CCAs and CCOs held by the Company on December 31, 2020.

(g) If PacifiCorp receives free or subsidized CCAs or CCOs, please provide a narrative explanation of the circumstances of this, including the source and intended purpose of the CCAs or CCOs, and how this relates to the Company's allowance allocation from CARB.

(h) If PacifiCorp receives free or subsidized CCAs or CCOs, please list the total quantity of CCAs of CCOs received in each month since January 1, 2014. Please provide this data in electronic spreadsheet format with all formulas and cell references intact, including commentary on the amount and value of all subsidies.

[1] "Excess" refers to CCAs or CCOs held in excess of the Company's compliance requirement for the period ending December 31, 2020.

UE 390 / PacifiCorp
May 21, 2021
OPUC Data Request 31 – 1st Revised

**1st Revised Response to OPUC Data Request 31**

In further support of the Company's prior responses to OPUC Data Request 31, the Company provides the following 1st Revised response relevant to subpart (e):

While preparing the Company's response to OPUC Data Request 131, the Company became aware of a missing entry in Confidential Attachment OPUC 31-2 1st Supplemental. The Company hereby provides a correct version of Confidential Attachment OPUC 31-2 1st Supplemental which has been updated to now include the missing entry. The referenced missing entry, on tab "CCO Deposit into CITSS Account," has been highlighted blue for ease of reference. All other information and attachments associated with the Company's 1st Supplemental response to OPUC Data Request 31 remain unchanged and valid.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

UE 390 / PacifiCorp
May 27, 2021
OPUC Data Request 31 – 2nd Supplemental

**OPUC Data Request 31**

**Energy Imbalance Market (EIM)** – With regard to the Company's purchase and sale of CCAs or CCOs:

(a) Please provide a narrative explanation of how PacifiCorp purchases or sells CCAs, including details of how the Company ensures that the most advantageous price is achieved. If the Company's response differs for any of the sub-categories listed in Staff Data Request (DR) 29 section "a", please provide a detailed response for each.

(b) Please provide a narrative explanation of how PacifiCorp purchases or sells CCOs, including detail of how the Company ensures that the most advantageous price is achieved. If the Company's response differs for any of the sub-categories listed in Staff DR 29 section "a", please provide a detailed response for each.

(c) Please provide all internal policies and procedures relating to the purchase or sale of CCAs or CCOs.

(d) Please separately list PacifiCorp's CCA and CCO purchases since January 1, 2014, including the total price, quantity of credits purchased, and credit price, in electronic spreadsheet format with all formulas and cell references intact.

(e) Please separately list PacifiCorp's CCA and CCO sales since January 1, 2014, including the total price, quantity of credits purchased, and credit price, in electronic spreadsheet format with all formulas and cell references intact.

(f) Please indicate the number of excess[1] CCAs and CCOs held by the Company on December 31, 2020.

(g) If PacifiCorp receives free or subsidized CCAs or CCOs, please provide a narrative explanation of the circumstances of this, including the source and intended purpose of the CCAs or CCOs, and how this relates to the Company's allowance allocation from CARB.

(h) If PacifiCorp receives free or subsidized CCAs or CCOs, please list the total quantity of CCAs of CCOs received in each month since January 1, 2014. Please provide this data in electronic spreadsheet format with all formulas and cell references intact, including commentary on the amount and value of all subsidies.

[1] "Excess" refers to CCAs or CCOs held in excess of the Company's compliance requirement for the period ending December 31, 2020.

UE 390 / PacifiCorp
May 27, 2021
OPUC Data Request 31 – 2nd Supplemental

**2nd Supplemental Response to OPUC Data Request 31**

In further support of the Company's prior responses to OPUC Data Request 31, the Company advises as follows:

(d) The Company's attachments in response to OPUC Data Request 31 subpart (d) and (e), specifically Confidential Attachment OPUC 31-2, Confidential Attachment OPUC 31-2 1st Supplemental, and the corrected version of Confidential Attachment OPUC 31-2 1st Supplemental, have been removed from Huddle after discussions between PacifiCorp and Public Utility Commission of Oregon OPUC staff.

The Company's response in this and any and all previous subparts to OPUC Data Request 31 relates to the modeling of GHG benefits in the 2022 transition adjustment mechanism (TAM), and does not include or indicate any bidding strategy, past, present or future, in which the Company has or intends to engage in any California Air Resources Board (CARB) auction, nor bid or acceptable prices or quantities of any past or present auction, nor set forth an intent to participate or not participate in any auction, nor any management approval processes with respect to any of the foregoing. The Company's response in any previous subparts to OPUC Data Request 31 provides a general description of the CARB consignment process.

# Confidential Staff Exhibit

# “Attachment to PacifiCorp’s response to Staff DR 33”

# is

# filed in electronic format

# Confidential Staff Exhibit

# “Relevant attachment to PacifiCorp’s first supplemental response to Staff DR 114”

# is

# filed in electronic format

# Confidential Staff Exhibit

# "Relevant attachment to PacifiCorp's response to Staff DR 124"

# is

# filed in electronic format

UE 390 / PacifiCorp
May 25, 2021
OPUC Data Request 125

**OPUC Data Request 125**

**EIM**
The Company's response to DR 29, section (e) states that "the quantity and type of California Carbon Offsets (CCO) which the Company can use is set by California's cap and trade regulation." Please indicate the specific limits that apply to PacifiCorp. If the Company's response differs for any of the categories listed in DR 123, please provide a separate response for each category.

**Response to OPUC Data Request 125**

PacifiCorp objects to this request as unreasonably cumulative, overly broad, unduly burdensome, outside the scope of this proceeding, and not reasonably calculated to lead to admissible evidence. Additionally, the information requested includes information regarding PacifiCorp's California Air Resources Board (CARB) compliance for PacifiCorp's retail service territory and is outside the scope of this proceeding. Without waiving the foregoing objection, PacifiCorp responds as follows:

The Company interprets the reference to "DR 29, section (e)" and "DR 123" to be references to the Company's responses to OPUC Data Request 29 subpart (e) and OPUC Data Request 123. Based on the foregoing interpretation, the Company responds as follows:

There are no specific limits on the use of California Carbon Offsets (CCO) that apply to PacifiCorp other than what is set by California cap and trade regulation.

UE 390 / PacifiCorp
May 24, 2021
OPUC Data Request 129

**OPUC Data Request 129**

**EIM**
Please indicate whether the Company receives GHG revenue from EIM for its wind generator units. If yes, please supplement the Company's response to DR 33 with information relating to the Company's wind generator units.

**Confidential Response to OPUC Data Request 129**

The Company interprets the reference to "DR 33" to be a reference to the Company's response to OPUC Data Request 33. Based on the foregoing interpretation, the Company responds as follows:

Yes, the Company can receive greenhouse gas (GHG) revenue from the energy imbalance market (EIM) for PacifiCorp's wind generating facilities. Since PacifiCorp joined the EIM, there has been one wind generating facility **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]** from which the Company received GHG revenues from the EIM. Information regarding **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]** was provided with the Company's response to OPUC Data Request 33, specifically Confidential Attachment OPUC 33, tab "2014 GHG Revenue."

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

UE 390 / PacifiCorp
May 24, 2021
OPUC Data Request 130

**OPUC Data Request 130**

**EIM**
Please provide a narrative update on the status of CAISO's proposed day-ahead market, including detail of the Company's engagement with CAISO regarding this matter.

**Response to OPUC Data Request 130**

Due, in part, to the California Independent System Operator's (CAISO) focus on the 2021 Summer Preparedness Initiative, the extended day-ahead market (EDAM) initiative has been on hold since July 27, 2020. The CAISO has not yet communicated when it intends to continue the initiative.

UE 390 / PacifiCorp
May 24, 2021
OPUC Data Request 131

**OPUC Data Request 131**

**EIM**
Regarding the Company's use of California Carbon Offsets (CCO) for California Air Resources Board (CARB) compliance.

(a) Has the Company engaged in any other agreements to purchase CCOs, similar to the agreement which previously existed to purchase CCOs from Farm Power Lynden?

(b) Please list the calendar years in which the Company used CCOs to meet its CARB compliance requirement.

(c) For each year listed in response, please indicate the number of CCOs used for Compliance. In this response, please provide the total quantity of CCOs used in each year, and the percentage of the Company's overall CARB compliance requirement which was met using CCOs.

**Response to OPUC Data Request 131**

PacifiCorp objects to this request as unreasonably cumulative, overly broad, unduly burdensome, outside the scope of this proceeding, and not reasonably calculated to lead to admissible evidence. Additionally, the information requested includes information regarding PacifiCorp's California Air Resources Board (CARB) compliance for PacifiCorp's retail service territory and is outside the scope of this proceeding. Without waiving the foregoing objection, PacifiCorp responds as follows:

(a) The Company has not engaged in any other agreements to purchase California Carbon Offsets (CCO).

(b) CCOs were used for compliance in 2018 and 2019 to meet CARB compliance requirement. 2018 was a conclusion of a triennial compliance period 2016 through 2018.

(c) The Company is unable to provide the requested information at this time due to concerns that certain of the requested information is considered proprietary and protected by CARB. The Company will supplement this response if it is able to provide some or all of the requested information, and after concluding discussions with CARB.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

UE 390 / PacifiCorp
June 1, 2021
OPUC Data Request 150

**OPUC Data Request 150**

**EIM**
Please refer to the Stipulation in Docket No. UE 375, paragraph 19.c., wherein PacifiCorp "agrees to provide additional information on the California Independent System Operatory's (CAISO) calculation of EIM benefits:

(a) Please provide the Company's calculation of the Flex Transfer Benefit, in electronic workbook format with all cells and formulas intact, including all underlying data, for the 2021 TAM.
(b) Please indicate what historical period was used to forecast the Flex Transfer Benefit for the 2021 TAM. In this response, please provide specific dates, and provide references to the specific cells in which this historical data appears in the electronic workbooks provided in response to section (a).
(c) Please provide a narrative explanation of the data used to forecast the Flex Transfer Benefit for the 2021 TAM. In this response, please indicate the data source, the payments represented, and any other information which helps to identify the payments.
(d) Please indicate whether the Flex Transfer Benefit has been included in the 2022 NPC forecast, and if the methodology has changed from that used in the 2021 TAM forecast.
(e) If no to section (d):
    i. Please provide an explanation of why the Flex Transfer Benefit has not been included.
    ii. Please provide an update to the calculation provided in response to section (a), including recent data, resulting in a Flex Transfer Benefit calculated value for the 2022 NPC forecast.
(f) If yes to section (d):
    i. Please indicate what dollar value is included as a benefit.
    ii. Please provide the Company's calculation of the value shown in response to part (i).

**Response to OPUC Data Request 150**

The Company assumes that the reference to "California Independent System **Operatory**'s (CAISO)" is intended to be a reference to the California Independent System **Operator** (CAISO). Based on the foregoing correction, the Company responds as follows:

UE 390 / PacifiCorp
June 1, 2021
OPUC Data Request 150

(a) PacifiCorp does not generate a separate calculation of "Flex Transfer Benefits" as the process of assembling these values is onerous and financial impact is negligible.

(b) Does not apply.

(c) Does not apply.

(d) Does not apply.

(e) (i) "Flex Transfer Benefits" are considered separate from energy imbalance market (EIM) inter-regional transfer benefits in the context of net power costs (NPC), therefore the EIM benefits forecast does not capture those benefits. The financial impact of the "Flex Transfer Benefits" has been negligible, and as such, has not been included in the forecast.

(ii) Does not apply.

(f) Does not apply.

UE 390 / PacifiCorp
June 1, 2021
OPUC Data Request 151

**OPUC Data Request 151**

**EIM**
Please refer to testimony provided by the Company in Docket No. UE 375, PAC/500, Webb/76, line 19 and 20, which states "the flexible reserve benefit changed from 104 MW to 92 MW based on the most recent information":

(a) Please indicate what flexible reserve benefit has been modeled in the 2022 NPC forecast in MW.
(b) Please indicate where the value provided in response to section (a) can be found in the work papers provided to Staff in response to Data Request (DR) 19, including references to specific workbooks and cells. If this data has not yet been provided to Staff, please provide all work papers and input data used by the Company to calculate this value in electronic workbook format, with all cells and formulas intact, including references to specific workbooks and cells where the value provided in response to section (a) can be found in the provided workbooks.
(c) Please indicate what historic period was used to calculate the value provided in response to section (a).

**Response to OPUC Data Request 151**

(a) Please refer to the Company's 1st Supplemental response to OPUC Data Request 19.

(b) Please refer to the Company's 1st Supplemental response to OPUC Data Request 19.

(c) The flexible reserve benefit in the Company's 2022 transition adjustment mechanism (TAM) is based on the Flexible Reserve Study in PacifiCorp's 2019 Integrated Resource Plan (IRP). In that study, PacifiCorp used the historical distribution of energy imbalance market (EIM) diversity benefits from March 2018 through the beginning of the study in July 2018. The California Independent System Operator (CAISO_ identified an error in their calculation of uncertainty requirements in early 2018, therefore data prior to March 2018 was not valid. For additional details, please refer to the 2019 IRP, specifically Volume II, Appendix F (Flexible Reserve Study). PacifiCorp's 2019 IRP is publicly available and can be accessed by utilizing the following website link:

[Integrated Resource Plan (pacificorp.com)]

# Confidential Staff Exhibit

# “Attachment to PacifiCorp’s response to Staff DR 174”

# is

# filed in electronic format

# 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 26, 2021

DATA REQUEST RESPONSE CENTER
PACIFICORP
825 NE MULTNOMAH STREET STE 2000
PORTLAND, OR 97232
datarequest@pacificorp.com

| RE: | Docket No. | OPUC Request Nos. | Response Due By |
|---|---|---|---|
| | UE 390 | DR 175 | June 9, 2021 |

Please provide responses to the following request for data by the due date. Please note that all responses must be posted to the PUC Huddle account. Contact the undersigned before the response due date noted above if the request is unclear or if you need more time. In the event any of the responses to the requests below include spreadsheets, the spreadsheets should be in electronic form with cell formulae intact.

**Topic or Keyword: List of Corrections or Omissions dated May 25, 2021.**

175. Please provide all work papers, all source or reference documents, and any other relevant information related to the corrections outlined in the "List of Corrections or Omissions" posted by PacifiCorp on May 25, 2021.

Please name your responsive file to include the Data Request number. Once you have posted your response to the Data Request to the PUC Huddle account, use the "Sharing" feature of Huddle to generate an email to authorized parties notifying them that the response has been posted. In the body of the generated email, list the Data Request number associated with your response.

You must mark confidential responses as such and post them to Huddle in the appropriate "Confidential" folder. Access to Confidential folders is limited to individuals who have signed the protective order. You should not send confidential documents (hard copy or electronic) separately to the Commission or its Staff; you should post confidential responses only to the Huddle account.

Should you need to request an extension to the due date for the data responses you will need to contact the staff attorney assigned to the case for approval.

Questions regarding the use of Huddle should be directed to puc.datarequests@puc.oregon.gov.

/s/ John Crider
Administrator

Staff Initiator: Moya Enright moya.enright@puc.oregon.gov 503-508-7672

CASE: UE 390
WITNESS: MOYA ENRIGHT

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

## STAFF EXHIBIT 103

## Exhibits in Support
## Of Opening Testimony

**June 9, 2021**

Staff/103
Enright/1

**Futures Daily Market Report for Physical Environmental**
**27-May-2021**

| COMMODITY NAME | CONTRACT MONTH | DAILY PRICE RANGE | | | | SETTLE | | VOLUME AND OI TOTALS | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | OPEN# | HIGH | LOW | CLOSE# | PRICE | CHANGE | TOTAL VOLUME | OI | CHANGE | EFP | EFS | BLOCK VOLUME | SPREAD VOLUME |
| **CAZ-California Carbon Allowance Vintage 2021 Future** | | | | | | | | | | | | | | |
| CAZ | Jun21 | 19.14 | 19.50 | 19.08 | 19.38 | 19.38 | 0.10 | 1,404 | 14,340 | 2,189 | 0 | 0 | 1,269 | 648 |
| CAZ | Jul21 | | | | | 19.48 | 0.12 | 0 | 325 | 0 | 0 | 0 | 0 | 0 |
| CAZ | Aug21 | | | | | 19.57 | 0.12 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CAZ | Sep21 | | | | | 19.67 | 0.13 | 300 | 9,009 | 0 | 0 | 0 | 300 | 300 |
| CAZ | Oct21 | | | | | 19.77 | 0.13 | 0 | 500 | 0 | 0 | 0 | 0 | 0 |
| CAZ | Nov21 | | | | | 19.86 | 0.13 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CAZ | Dec21 | 19.76 | 20.07 | 19.60 | 19.94 | 19.96 | 0.13 | 6,987 | 100,977 | 915 | 0 | 0 | 4,374 | 615 |
| CAZ | Jan22 | | | | | 20.06 | 0.13 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CAZ | Feb22 | | | | | 20.15 | 0.13 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CAZ | Mar22 | | | | | 20.25 | 0.13 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CAZ | Apr22 | | | | | 20.34 | 0.13 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CAZ | May22 | | | | | 20.44 | 0.13 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CAZ | Jun22 | | | | | 20.53 | 0.13 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CAZ | Jul22 | | | | | 20.63 | 0.13 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CAZ | Aug22 | | | | | 20.72 | 0.13 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CAZ | Sep22 | | | | | 20.82 | 0.13 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CAZ | Oct22 | | | | | 20.91 | 0.13 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CAZ | Nov22 | | | | | 21.01 | 0.13 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CAZ | Dec22 | 20.90 | 20.90 | 20.90 | 20.90 | 21.10 | 0.13 | 25 | 1,505 | 25 | 0 | 0 | 0 | 0 |
| CAZ | Jan23 | | | | | 21.19 | 0.13 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CAZ | Feb23 | | | | | 21.28 | 0.13 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CAZ | Mar23 | | | | | 21.37 | 0.13 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CAZ | Apr23 | | | | | 21.46 | 0.13 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CAZ | May23 | | | | | 21.55 | 0.13 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CAZ | Jun23 | | | | | 21.64 | 0.13 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

**Futures Daily Market Report for Physical Environmental**
**27-May-2021**

| COMMODITY NAME | CONTRACT MONTH | DAILY PRICE RANGE | | | | SETTLE | | VOLUME AND OI TOTALS | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | OPEN# | HIGH | LOW | CLOSE# | PRICE | CHANGE | TOTAL VOLUME | OI | CHANGE | EFP | EFS | BLOCK VOLUME | SPREAD VOLUME |
| **CCO-California Carbon Offset Future** | | | | | | | | | | | | | | |
| CCO | Jun21 | 13.75 | 13.75 | 13.75 | 13.75 | 13.77 | 0.08 | 25 | 25 | 25 | 0 | 0 | 0 | 0 |
| CCO | Jul21 | | | | | 13.84 | 0.08 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CCO | Aug21 | | | | | 13.91 | 0.09 | 0 | 64 | 0 | 0 | 0 | 0 | 0 |
| CCO | Sep21 | 14.00 | 14.00 | 14.00 | 14.00 | 14.00 | 0.11 | 10 | 60 | 10 | 0 | 0 | 0 | 0 |
| CCO | Oct21 | | | | | 14.06 | 0.11 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CCO | Nov21 | | | | | 14.13 | 0.11 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CCO | Dec21 | | | | | 14.19 | 0.11 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CCO | Jan22 | | | | | 15.82 | 0.10 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CCO | Feb22 | | | | | 15.90 | 0.10 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CCO | Mar22 | | | | | 15.97 | 0.10 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CCO | Apr22 | | | | | 16.05 | 0.10 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CCO | May22 | | | | | 16.12 | 0.10 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CCO | Jun22 | | | | | 16.20 | 0.10 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CCO | Jul22 | | | | | 16.27 | 0.10 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CCO | Aug22 | | | | | 16.35 | 0.10 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CCO | Sep22 | | | | | 16.42 | 0.10 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CCO | Oct22 | | | | | 16.50 | -0.64 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CCO | Nov22 | | | | | 17.33 | 0.11 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CCO | Dec22 | | | | | 17.41 | 0.05 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CCO | Aug23 | | | | | 18.00 | -0.18 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CCO | Sep23 | | | | | 18.36 | 0.11 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CCO | Oct23 | | | | | 18.44 | 0.11 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CCO | Dec23 | | | | | 18.59 | 0.11 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Totals for CCO:** | | | | | | | | **35** | **149** | **35** | **0** | **0** | **0** | **0** |

CASE: UE 390
WITNESS: MOYA ENRIGHT

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

## STAFF EXHIBIT 104

## Exhibits in Support
## Of Opening Testimony

**June 9, 2021**

| RPSID | RPSID Suffix | Facility Name | Facility City | Facility State | Nameplate Capacity | Technology | Organization Name | Facility Owner | Certification Status |
|---|---|---|---|---|---|---|---|---|---|
| 60780 | E | Bogus Creek - Lower Cold Springs | Montague | California | 0.1 | Small Hydroelectric | PacifiCorp | Harold E. Foster & Robert Z. Walker | Approved |
| 60781 | E | Bogus Creek - Upper Cold Springs | Montague | California | 0.1 | Small Hydroelectric | PacifiCorp | Harold E. Foster & Robert Z. Walker | Approved |
| 60537 | A | Copco 1 | Hornbrook | California | 20 | Small Hydroelectric | PacifiCorp | PacifiCorp | Approved |
| 60538 | A | Copco 2 | Hornbrook | California | 27 | Small Hydroelectric | PacifiCorp | PacifiCorp | Approved |
| 60539 | A | Fall Creek | Hornbrook | California | 2.2 | Small Hydroelectric | PacifiCorp | PacifiCorp | Approved |
| 60540 | A | Iron Gate | Hornbrook | California | 18 | Small Hydroelectric | PacifiCorp | PacifiCorp | Approved |
| 60778 | E | Lake Siskiyou | Mt. Shasta | California | 5 | Small Hydroelectric | PacifiCorp | Siskiyou Power Authority | Approved |
| 60782 | A | Paul Luckey Hydro | Hornbrook | California | 0.05 | Small Hydroelectric | PacifiCorp | ward Paul Luckey and Joanne Luckey Revocable T | Approved |
| 60796 | A | Cove | Grace | Idaho | 7.5 | Small Hydroelectric | PacifiCorp | PacifiCorp | Approved |
| 60791 | A | Last Chance | Grace | Idaho | 1.73 | Small Hydroelectric | PacifiCorp | PacifiCorp | Approved |
| 60585 | A | Oneida | Preston | Idaho | 30 | Small Hydroelectric | PacifiCorp | PacifiCorp | Approved |
| 60586 | A | Paris | Paris | Idaho | 0.72 | Small Hydroelectric | PacifiCorp | PacifiCorp | Approved |
| 60590 | A | Soda | Soda Springs | Idaho | 14 | Small Hydroelectric | PacifiCorp | PacifiCorp | Approved |
| 60564 | A | Wolverine Creek | Bingham County | Idaho | 64.5 | Wind | PacifiCorp | | Approved |
| 60579 | A | Big Fork | Big Fork | Montana | 4.15 | Small Hydroelectric | PacifiCorp | PacifiCorp | Approved |
| 60522 | A | Bend | Bend | Oregon | 1.1 | Small Hydroelectric | PacifiCorp | PacifiCorp | Approved |
| 60507 | A | Clearwater 1 | Ideyld Park | Oregon | 15 | Small Hydroelectric | PacifiCorp | PacifiCorp | Approved |
| 60508 | A | Clearwater 2 | Ideyld Park | Oregon | 26 | Small Hydroelectric | PacifiCorp | PacifiCorp | Approved |
| 60580 | A | Cline Falls | Redmond | Oregon | 1 | Small Hydroelectric | PacifiCorp | PacifiCorp | Approved |
| 60509 | A | Eagle Point | Eagle Point | Oregon | 2.8 | Conduit Hydroelectric | PacifiCorp | PacifiCorp | Approved |
| 60524 | A | Eastside | Klamath Falls | Oregon | 3.2 | Small Hydroelectric | PacifiCorp | PacifiCorp | Approved |
| 60513 | A | Fish Creek | Idleyld Park | Oregon | 11 | Small Hydroelectric | PacifiCorp | PacifiCorp | Approved |
| 60562 | A | Leaning Juniper | Arlington | Oregon | 100.5 | Wind | PacifiCorp | PacifiCorp | Approved |
| 60530 | A | Prospect 1 | Prospect | Oregon | 3.8 | Small Hydroelectric | PacifiCorp | PacifiCorp | Approved |
| 60514 | A | Prospect 3 | Prospect | Oregon | 7.2 | Small Hydroelectric | PacifiCorp | PacifiCorp | Approved |
| 60531 | A | Prospect 4 | Prospect | Oregon | 1 | Small Hydroelectric | PacifiCorp | PacifiCorp | Approved |
| 60515 | A | Slide Creek | Idleyld Park | Oregon | 18 | Small Hydroelectric | PacifiCorp | PacifiCorp | Approved |
| 60516 | A | Soda Springs | Idleyld Park | Oregon | 11 | Small Hydroelectric | PacifiCorp | PacifiCorp | Approved |
| 60517 | A | Wallowa Falls | Joseph | Oregon | 1.1 | Small Hydroelectric | PacifiCorp | PacifiCorp | Approved |
| 60532 | A | Westside | Klamath Falls | Oregon | 0.6 | Small Hydroelectric | PacifiCorp | PacifiCorp | Approved |
| 60577 | A | American Fork | Alpine | Utah | 0.95 | Small Hydroelectric | PacifiCorp | PacifiCorp | Approved |
| 60578 | A | Ashton | Fremont | Utah | 6.85 | Small Hydroelectric | PacifiCorp | PacifiCorp | Approved |
| 60820 | A | Blundell I | Milford | Utah | 26.1 | Geothermal | PacifiCorp | PacifiCorp | Approved |
| 60821 | A | Blundell II | Milford | Utah | 12 | Geothermal | PacifiCorp | PacifiCorp | Approved |
| 60581 | A | Cutler | Collinston | Utah | 30 | Small Hydroelectric | PacifiCorp | PacifiCorp | Approved |
| 60582 | A | Fountain Green | Fountain Green | Utah | 0.16 | Small Hydroelectric | PacifiCorp | PacifiCorp | Approved |
| 60583 | A | Granite | Salt Lake City | Utah | 2 | Small Hydroelectric | PacifiCorp | PacifiCorp | Approved |
| 60584 | A | Gunlock | Veyo | Utah | 0.75 | Small Hydroelectric | PacifiCorp | PacifiCorp | Approved |
| 60587 | A | Pioneer | Pioneer | Utah | 5 | Small Hydroelectric | PacifiCorp | PacifiCorp | Approved |
| 60588 | A | Sand Cove | Veyo | Utah | 0.8 | Small Hydroelectric | PacifiCorp | PacifiCorp | Approved |
| 60589 | A | Snake Creek | Heber City | Utah | 1.18 | Small Hydroelectric | PacifiCorp | PacifiCorp | Approved |
| 60591 | A | Stairs | Salt Lake City | Utah | 1 | Small Hydroelectric | PacifiCorp | PacifiCorp | Approved |
| 60592 | A | Upper Beaver | Beaver | Utah | 2.52 | Small Hydroelectric | PacifiCorp | PacifiCorp | Approved |
| 60593 | A | Veyo | Veyo | Utah | 0.5 | Small Hydroelectric | PacifiCorp | PacifiCorp | Approved |
| 60595 | A | Weber | South Ogden | Utah | 3.85 | Small Hydroelectric | PacifiCorp | PacifiCorp | Approved |
| 60819 | A | Goodnoe Hills | Goldendale | Washington | 94 | Wind | PacifiCorp | PacifiCorp | Approved |
| 60729 | A | Marengo | Dayton | Washington | 140.4 | Wind | PacifiCorp | PacifiCorp | Approved |
| 60730 | A | Marengo II | Dayton | Washington | 70.2 | Wind | PacifiCorp | PacifiCorp | Approved |
| 61017 | A | Campbell Hill - Three Buttes | Glenrock | Wyoming | 99 | Wind | PacifiCorp | Three Buttes Windpower, LLC | Approved |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 61188 | A | Dunlap I | Medicine Bow | Wyoming | 111 | Wind | PacifiCorp | PacifiCorp | Approved |
| 60561 | A | Foote Creek 1 | McFadden | Wyoming | 40.8 | Wind | PacifiCorp | PacifiCorp | Approved |
| 60805 | A | Glenrock I | Glenrock | Wyoming | 99 | Wind | PacifiCorp | PacifiCorp | Approved |
| 60804 | A | Glenrock III | Glenrock | Wyoming | 39 | Wind | PacifiCorp | PacifiCorp | Approved |
| 60899 | A | High Plains | Rock River | Wyoming | 99 | Wind | PacifiCorp | PacifiCorp | Approved |
| 61675 | A | J BAR 9 Ranch | Park | Wyoming | 0.1 | Wind | PacifiCorp | J Bar 9 Ranch, Inc. | Approved |
| 60896 | A | McFadden Ridge | Rock River | Wyoming | 28.5 | Wind | PacifiCorp | PacifiCorp | Approved |
| 60811 | A | Mountain Wind I | Fort Bridger | Wyoming | 61 | Wind | PacifiCorp | Mountain Wind Power, LLC | Approved |
| 60812 | A | Mountain Wind II | Fort Bridger | Wyoming | 79.5 | Wind | PacifiCorp | Mountain Wind Power II LLC | Approved |
| 60563 | E | Rock River 1 | McFadden | Wyoming | 50 | Wind | PacifiCorp | Rock River I, LLC | Approved |
| 60806 | A | Rolling Hills | Glenrock | Wyoming | 99 | Wind | PacifiCorp | PacifiCorp | Approved |
| 60807 | A | Seven Mile Hill I | Medicine Bow | Wyoming | 99 | Wind | PacifiCorp | PacifiCorp | Approved |
| 60808 | A | Seven Mile Hill II | Medicine Bow | Wyoming | 19.5 | Wind | PacifiCorp | PacifiCorp | Approved |
| 61199 | A | Top of the World | Glenrock | Wyoming | 200 | Wind | PacifiCorp | Top of the World Wind Energy LLC | Approved |
| 60594 | A | Viva Naughton | Kemmerer | Wyoming | 0.74 | Small Hydroelectric | PacifiCorp | PacifiCorp | Approved |
| | | **Total MW capacity registered for California RPS** | | | **1,922** | | | | |

Previously released November 4, 2019

Revised November 4, 2020: Updates were made to include new reporters and/or revised da

California Air Resources Board

The total 2018 emissions subject to a compliance obligation in the Cap-and-Trade Program equals 319,882,513 metric tons CO2e,

**Annual Summary of GHG Mandatory Reporting Non-Confidential Data for Calendar Year 2018**

See the "Introduction" tab and the "Column Descriptions" tab for important information about the data shown.

| | | | Total Emissions (metric tons $CO_2e$) | | Facility Reported GHG Data (metric tons CO2e) | | | | | ARB Calculated Covered Emissions (metric tons CO2e) | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ARB ID | Facility Name | Report Year | Total $CO_2e$ (combustion, process, vented, and supplier) | AEL | Emitter CO2e from Non-Biogenic Sources and CH4 and N2O from Biogenic Fuels | Emitter CO2 from Biogenic Fuels | Fuel Supplier CO2e from Non-Biogenic Fuels and CH4 and N2O from Biogenic Fuels | Fuel Supplier CO2 from Biogenic Fuels | Electricity Importer CO2e | Emitter Covered Emissions | Fuel Supplier Covered Emissions | Electricity Importer Covered Emissions | Total Covered Emissions | Total Non-Covered Emissions |
| 104708 | Idaho Power | 2018 | 59,843 | No | 0 | 0 | 0 | 0 | 59,843 | 0 | 0 | 59,843 | 59,843 | 0 |
| 3003 | PacifiCorp | 2018 | 674,176 | No | 0 | 0 | 0 | 0 | 674,176 | 0 | 0 | 674,176 | 674,176 | 0 |
| 2127 | Portland General Electric Company | 2018 | 419,128 | No | 0 | 0 | 0 | 0 | 419,128 | 0 | 0 | 156,002 | 156,002 | 263,126 |

Released November 4, 2020

California Air Resources Board

The total 2019 emissions subject to a compliance obligation in the Cap-and-Trade Program equals 311,192,372 metric tons CO2e,

**Annual Summary of GHG Mandatory Reporting Non-Confidential Data for Calendar Year 2019**

CALIFORNIA AIR RESOURCES BOARD

See the "Introduction" tab and the "Column Descriptions" tab for important information about the data shown.

| | | | Total Emissions (metric tons $CO_2e$) | | Facility Reported GHG Data (metric tons CO2e) | | | | | ARB Calculated Covered Emissions (metric tons CO2e) | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ARB ID | Facility Name | Report Year | Total $CO_2e$ (combustion, process, vented, and supplier) | AEL | Emitter CO2e from Non-Biogenic Sources and CH4 and N2O from Biogenic Fuels | Emitter CO2 from Biogenic Fuels | Fuel Supplier CO2e from Non-Biogenic Fuels and CH4 and N2O from Biogenic Fuels | Fuel Supplier CO2 from Biogenic Fuels | Electricity Importer CO2e | Emitter Covered Emissions | Fuel Supplier Covered Emissions | Electricity Importer Covered Emissions | Total Covered Emissions | Total Non-Covered Emissions |
| 104708 | Idaho Power | 2019 | 21,472 | | 0 | 0 | 0 | 0 | 21,472 | 0 | 0 | 21,472 | 21,472 | 0 |
| 3003 | PacifiCorp | 2019 | 778,613 | | 0 | 0 | 0 | 0 | 778,613 | 0 | 0 | 778,613 | 778,613 | 0 |
| 2127 | Portland General Electric Company | 2019 | 302,169 | | 0 | 0 | 0 | 0 | 302,169 | 0 | 0 | 92,524 | 92,524 | 209,645 |

CASE: UE 390
WITNESS: HEATHER COHEN

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

## STAFF EXHIBIT 200

## Opening Testimony

**June 9, 2021**

**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, Finance and Audit Division of the Public Utility Commission of Oregon (Commission). 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 discuss the PacifiCorp (PAC or Company) 2022 TAM filing and Staff's review of and recommended Commission action regarding: the Day Ahead/Real Time (DA-RT) Adder, Wholesale Transactions, and the Official Forward Price Curve (OFPC) and OFPC Scalars.

**Q. Did you prepare any additional exhibits for this docket?**

A. Yes. I prepared the following Staff Exhibits:

- Staff/201: Witness Qualification Statement
- Staff/202: PacifiCorp's responses to Staff Data Requests 6, 11, 12, 112 and 134.
- Staff/203: PacifiCorp's confidential responses to Staff Data Requests 1, 2 (electronic format only), 8, and 21-2 (response and Attachment 2 only).

**Q. How is your testimony organized?**

A. My testimony is organized as follows:

**Q. Please summarize your recommendations and adjustments.**

A. Staff's recommendations and adjustments are as follows:

1. DA-RT

No adjustment recommended. Staff recommends a thorough review conducted by PacifiCorp, with engagement from the parties, to prove the value of the DA-RT Adder.

2. Wholesale Transactions

No adjustment recommended.

3. Official Forward Price Curve (OFPC) and OFPC Scalars

No adjustment recommended.

## ISSUE 1, DAY AHEAD/REAL TIME (DA-RT) ADJUSTMENT

**Q. Please explain the DA-RT adjustment.**

A. The DA-RT adder is made up of two adjustments: (1) the volume adder, which addresses the fact that the Company must transact in the market in set quantities while GRID does not have this restriction and transacts all quantities of MW; and (2) the price adder, which produces different prices in GRID for system balancing and purchases in order to better reflect prices in the real-time market where the Company has historically bought more during higher-than-average-prices and sold more during lower-than-average price periods.[1]

**Q. What is the effect of DA-RT on the 2022 TAM?**

A. Staff queried the Company on this year's DA-RT adjustment and found that because the methodology is unchanged, no calculation was performed.[2] While the Company did not provide the calculation, it did provide the source of the adjustment in its work papers. Accordingly, Staff calculated the DA-RT adjustment for 2022 as $2.4 million.[3]

**Q. What is Staff's recommendation on this issue?**

A. While the DA-RT adder was created to compensate for claimed deficiencies in the GRID model, GRID's replacement model "AURORA" will be used to forecast NPC in the 2023 TAM.

---

[1] PAC/100, Webb/22.
[2] Staff/202, Cohen/7 (PacifiCorp Response to Staff DR 112).
[3] As instructed by the Company in DR 112, Staff added the cells AI162: AJ173 to calculate the West DART amount of expenditures/revenues.

In the UE 375 Stipulation for the 2021 TAM, the Company agreed to hold a workshop before filing the 2022 TAM, to provide information on the DA-RT Adder, as well as provide AURORA licenses to Commission Staff and Intervenors for each future TAM. In addition, PacifiCorp agreed to provide all inputs, data, model settings, constraints, and any other modelling changes.[4]

Although the Company did not use AURORA for the 2022 TAM as originally anticipated, Staff continues to support this approach, and recommends that the workshops described be provided in advance of the 2023 TAM filing. Staff also recommends that a thorough review be conducted by PacifiCorp, with engagement from parties, to prove that the DA-RT Adder is a valuable adjustment to NPC modeled in AURORA, rather than to assume its inclusion going forward.

[4] *In re PacifiCorp*, OPUC Docket No. UE 375, Order No. 20-392 at 3 (Oct. 30, 2020).

## ISSUE 2, WHOLESALE POWER TRANSACTIONS

**Q. Please provide an overview of your testimony on this issue.**

A. Staff provides an overview of how the Company transacts power, a description of the hubs used for power sales and purchases as well as a comparison of the 2022 and 2021 TAMs to illustrate the importance of timing in obtaining accurate findings. Staff issued 14 data requests to better understand the multi-year trends in wholesale transactions, specifically those related to the fluctuations of short-term sales and purchases due to the timing of the filing.

**Q. What wholesale power transactions are included in Net Power Costs (NPC)?**

A. NPC includes long-term firm sales, or contracts longer than one year, short-term sales, or contracts shorter than one year, system balancing transactions,[5] and power purchases from Qualifying Facilities (QF).

Although EIM transactions are not modelled in GRID, the Company tracks the dollar value of EIM GHG benefits and energy transfer benefits[6] under the header "system balancing purchases."[7] As can be seen in Figure 1, Staff has separated these values so that the dollar values of balancing transactions and EIM benefits can be more easily appreciated.

[5] System balancing transactions represent transactions forecasted by GRID to economically balance load and resources in the period.
[6] See Staff/100, Enright/Issue 2 for further discussion of the three categories of EIM benefits forecasted by PAC.
[7] PAC/102, Webb/4.

**Q. How do the wholesale power transactions differ from the 2021 TAM?**

A. Figure 1 illustrates a breakdown of Wholesale Transactions for the 2022 TAM as compared with the 2021 TAM final and initial filings. As can be seen from the Figure 1 (below), both short-term sales and purchases (in dollars) in the final 2021 TAM increased significantly from their 2021 initial filing amounts.[8] As such, we expect a large increase in both of these in Company updates for the 2022 TAM.

**FIGURE 1: WHOLESALE TRANSACTIONS IN 2022 AND 2021 TAM**

| | 2022 TAM | | 2021 TAM (Final) | | 2021 TAM (initial filing 2/20) | |
|---|---|---|---|---|---|---|
| | Sales | Purchases | Sales | Purchases | Sales | Purchases |
| Long Term Firm (inc. Mid-C) | 7,707,019 | 200,670,323 | 7,916,745 | 224,991,873 | 7,663,042 | 203,112,882 |
| Short Term Firm* | 3,818,140 | 3,004,200 | 49,825,310 | 15,447,140 | 4,870,100 | - |
| System Balancing (excl. EIM/GHG) | 240,929,186 | 176,127,279 | 291,866,224 | 141,060,710 | 269,087,647 | 131,040,001 |
| Qualifying Facilities | | 337,028,916 | | 335,389,101 | | 337,554,895 |
| Storage and Exchange | | 4,500,000 | | 5,400,000 | | 5,400,000 |
| Total | 252,454,345 | 721,330,717 | 349,608,279 | 722,288,825 | 281,620,789 | 677,107,778 |
| EIM/GHG Benefits (part of System Balancing Purchases) | | (57,523,956) | | (50,231,280) | | (64,594,041) |

This increase in short-term firm sales from initial filing to the final update filing is due to the fact that these short-term firm transactions, or hedges, are entered into on a rolling 36-month basis for the test period.[9] As such, PacifiCorp notes that the volume of short-term firm sales in the 2022 TAM are anticipated to increase significantly by the time the November update is filed.[10]

[8] PAC/102, Webb/1-4; UE 375 - PAC/102, Webb 1-4.
[9] PAC/100, Webb/19.
[10] Ibid.

**Q. Please describe how each element of the Company's forecasted wholesale power transactions are derived.**

A. Short and long term transactions reflect actual trades that have already been executed for delivery during the 2022 year, and will increase in each of PacifiCorp's scheduled updates to this filing, as the Company works toward its hedging goal for the year ahead.

System balancing transactions are forecasted by GRID to balance the system. These also include minor transactions such as emergency purchases[11] and trapped energy sales.[12]

Qualifying Facilities includes the cost of procuring power from PURPA projects and is based on forecasted generation and contract prices.[13] More information on this topic can be found in Staff/500 (Opening Testimony of Staff Witness Kathy Zarate).

Finally, benefits from wholesale transactions in the EIM, which cannot be modeled by GRID, are forecasted as a lump sum dollar value. This value is derived using the Company's proposed EIM benefits forecasting models, which are further discussed in Staff/100, Enright/Issue 2.

**Q. Please describe how the Company carries out wholesale purchases and sales.**

---

[11] Emergency purchases occur when resources in an area of the Company's system are fully dispatched, but transmission into the area is insufficient to meet the load in that area.
[12] Trapped energy occurs when generation in an area of the Company's system is backed down to minimum, but still exceeds the available transmission out of the area.
[13] UE 375 - Staff/200, Enright/24-25.

A. **[BEGIN CONFIDENTIAL]** [redacted][14]

[redacted][15] [redacted][16]

[redacted]

[redacted] **[END CONFIDENTIAL]**

**Q. How does the Company manage risks related to its wholesale trading operations?**

---

[14] Staff/203, Cohen/2-3 (PacifiCorp's Confidential Response to Staff DR 1).
[15] Staff/203, Cohen/3-4 (PacifiCorp's Confidential Response to Staff DR 1).
[16] Clarified by Paul Wood in PAC's TAM Technical Workshop Meeting, May 14, 2021.

A. **[BEGIN CONFIDENTIAL]** [redacted][17] **[END CONFIDENTIAL]**

**Q. Does the Company have to follow any guidance when making power purchases and/or sales?**

A. **[BEGIN CONFIDENTIAL]** [redacted][18] **[END CONFIDENTIAL]**

**Q. Has Staff analyzed the Company's historic wholesale trading behavior?**

A. Yes. Historically, Company power purchases and sales are **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** When reviewing trades in 2020, purchases are **[BEGIN CONFIDENTIAL]** [redacted][19] **[END CONFIDENTIAL]**

[17] Staff/203, Cohen/3-4 (PacifiCorp's Confidential Response to Staff DR 1).
[18] Staff/203, Cohen/3 (PacifiCorp's Confidential Response to Staff DR 1)
[19] Staff/203, Cohen/5 (PacifiCorp's confidential response to Staff DR 2 (electronic spreadsheet).

**FIGURE 2: 2020 WHOLESALE PURCHASES (MWH)**

**[BEGIN CONFIDENTIAL]**

[redacted]

**[END CONFIDENTIAL]**

When PacifiCorp sells power, it is **[BEGIN CONFIDENTIAL]** [redacted][20] **[END CONFIDENTIAL]**

**FIGURE 3: 2020 WHOLESALE SALES MWH**

**[BEGIN CONFIDENTIAL]**

[redacted]

**[END CONFIDENTIAL]**

[20] Staff/203, Cohen/5 (PacifiCorp's confidential response to Staff DR 2 (electronic spreadsheet)).

**Q. Are there contracts that have already been executed for the 2022 TAM?**

A. **[BEGIN CONFIDENTIAL]** [redacted][21] **[END CONFIDENTIAL]**

**FIGURE 4: 2022 EXECUTED CONTRACTS, SHORT TERM FIRM SALES**

**[BEGIN CONFIDENTIAL]**

[redacted]

**[END CONFIDENTIAL]**

**Q. How many MWh are typically bought and sold in a year and how much have been bought and sold thus far in the 2022 TAM?**

A. As illustrated below in confidential Figure 5, the last TAM (2021) concluded with total sales at **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** and total purchases of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** as compared with this year's forecast of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in sales and **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in purchases.

[21] UE 390 - Confidential 15 day Workpaper ORTAM22_STF (2012) FEB20 CONF

What is notable, as mentioned earlier, is the short-term sales and purchases. Compared to last year's short term sales and purchases, the Company **[BEGIN CONFIDENTIAL]** [redacted][22] **[END CONFIDENTIAL]**

[22] UE 390 - Webb Confidential Workpaper ORTAM22 NPC CONF PAC Workpaper ORTAM22 NPC Conf, NPC Tab, See UE 375 Webb Final ORTAM21 Fin Nov NPC Conf – TB and Pryor Increase.

**FIGURE 4: 2022 AND 2021 TAM COMPARED IN $ AND MWH**

**[BEGIN CONFIDENTIAL]**

[redacted]

**[END CONFIDENTIAL]**

**Q. How does the GRID forecast the remainder of the Company's trades, its system balancing transactions?**

A. The GRID model uses its internal optimization logic to identify the market hub, volume and time period for all system balancing transactions. GRID studies requirements, dispatchable resources, power and fuel prices, transmission constraints and market capacity limitation in determining a dispatch plan that satisfies all system requirements and minimizes cost.[23] Confidential Figure 6 demonstrates the forecasted system balancing trades in the 2022 TAM filing. **[BEGIN CONFIDENTIAL]** [redacted][24] **[END CONFIDENTIAL]**

[23] Staff/202, Cohen/2 (PacifiCorp's response to Staff DR 6).
[24] UE 390 - Webb Confidential Workpaper ORTAM22 NPC CONF PAC Workpaper ORTAM22 NPC Conf, NPC Tab

**FIGURE 5: 2022 SYSTEM BALANCING PURCHASES AND SALES**

**[BEGIN CONFIDENTIAL]**

[redacted]

**[END CONFIDENTIAL]**

**Q. Are the Company's short term firm transactions distributed across market nodes?**

As shown in confidential Figure 7, Short Term Firm Purchases occur **[BEGIN CONFIDENTIAL]** [redacted][25] **[END CONFIDENTIAL]**

[25] UE 390 - Webb Confidential Workpaper ORTAM22 NPC CONF PAC Workpaper ORTAM22 NPC Conf, NPC Tab

**FIGURE 6: 2022 SHORT TERM PURCHASES AND SALES HUBS**

**[BEGIN CONFIDENTIAL]**

[redacted]

**[END CONFIDENTIAL]**

**Q. How much energy (in dollars) has been bought and sold in the Energy Imbalance Market (EIM) historically?**

A. As shown in confidential Figures 7 and 8 below, there has been some variation in the EIM market from 2014-2020 where the highest sales or exports hovered around **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** as compared to the lowest of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** Similarly, purchases or imports varied from a low of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** to a high of **[BEGIN CONFIDENTIAL]** [redacted][26], [27] **[END CONFIDENTIAL]**

[26] Staff/203, Cohen/5 (PacifiCorp's confidential response to Staff DR 2 (electronic spreadsheet).
[27] Dollar values shown represent total revenues/expenses from/to EIM during the period.

**FIGURE 7: CAISO SALES AND PURCHASES 2017-2020**

**[BEGIN CONFIDENTIAL]**

[redacted]

[redacted]

**[END CONFIDENTIAL]**

**Q. Please describe the Company's Risk Management practices.**

A. PacifiCorp's risk management policy is **[BEGIN CONFIDENTIAL]** [redacted]

[redacted][28]

[redacted][29]

[redacted]

[28] Staff/203, Cohen/12-13 (PacifiCorp's confidential response to Staff DR 8, attachment A).
[29] Staff/203, Cohen/20-22 (PacifiCorp's confidential response to Staff DR 8, Attachment A).

[redacted][30]

[redacted][31]

[redacted]

[30] Staff/203, Cohen/22 (PacifiCorp's confidential response to Staff DR 8, Attachment A).
[31] Staff/203, Cohen/17 (PacifiCorp's confidential response to Staff DR 8, Attachment A).

[redacted][32] **[END CONFIDENTIAL]**

**Q. Have there been any recent changes in the Company's hedging practices?**

**[BEGIN CONFIDENTIAL]** [redacted]

[32] Staff/203, Cohen/18-20 (PacifiCorp's confidential response to Staff DR 8, Attachment A).

[redacted][33]

**[END CONFIDENTIAL]**

**Q. Does Staff have a recommended adjustment?**

A. No.

[33] Staff/203, Cohen/52 (PacifiCorp's confidential response to Staff DR 21, Attachment 2).

**ISSUE 3, OFFICIAL FORWARD PRICE CURVE (OFPC) AND OFPC SCALARS**

**Q. What is the Official Forward Price Curve (OFPC)?**

A. The OFPC in the TAM is the forecasted hourly market price which is fed into GRID. It is through this process that GRID optimizes the generation portfolio and makes the necessary market purchases and economic market sales.

The Company's gas and electricity official forward price curves are derived from a combination of forward market prices on a given quote day and a long-term fundamentals-based price forecast.[34]

- The first 37 months of the curve are based on the average of monthly broker quotes for that period.
- Months 38 through 49 are an average of the previous year market forwards and the next year's fundamentals price forecast.
- After month 49, a fundamentals-based forecast is used.

The Company then takes these monthly market prices and shapes them into an hourly series using price scalars in order to differentiate on-peak and off-peak schedules. These hourly price scalars were developed by the Company using observed historical hourly spot prices.

**Q. How recent is the data included in the OFPC?**

A. PacifiCorp's direct filing is based exclusively upon broker quotes which were obtained on December 31, 2020.[35]

[34] Staff/202, Cohen/6 (PacifiCorp's response to Staff DR 12).
[35] Ibid.

PacifiCorp will update its OFPC in line with the scheduled updates to the model. The July update will use the Company's March 31, 2021 OFPC. The Indicative filing and the Final filing are expected to use prices from within the allowable range (nine days prior to the Indicative filing and seven days prior to the Final filing).[36]

**Q. What is the Company's methodology for shaping the scalars?**

A. The OFPC begins as an average monthly price which gets shaped by the hour on a weekly basis.[37] For example, if prices are 10 percent higher than average for a particular hour, a factor of 1.1 would be applied. The monthly average price in GRID remains the same as OFPC monthly price, but each hour in a day type will be higher or lower to reflect typical patterns of hourly prices.[38]

**Q. Does Staff have any concerns about the Company's methodology?**

A. Prior to the 2020 TAM, the Company used five years of historical price data to shape the scalars but in 2020, the Company proposed to use only a single year of hourly market. As a response to Staff and Intervenor concerns about the change, the Company proposed ort use two years of data to shape the scalars. Staff finds this more reliable than one year.[39] In the 2020 TAM, Staff was also concerned with the use of the California-Oregon Border (COB) market hub when in reality the Mid-C market is a better barometer of the Company's

[36] Staff/202, Cohen/4 (PacifiCorp Response to Staff DR 11).
[37] UE 375 -Staff/100, Gibbens/12.
[38] Ibid.
[39] Ibid.

transactions, as noted in the previous discussion on wholesale transactions. The two years of data for the 2022 TAM includes CAISO and Mid-C prices via Intercontinental Exchange [40]

**Q. Has the Company increased the amount of data used to shape the scalars in this year's filing?**

A. Yes. The Company has included two years of data from CAISO and the Inter-Continental Exchange (ICE) to shape the scalars.[41] For the purposes of this TAM filing, Staff is satisfied with this approach.

**Q. Does Staff have a recommended adjustment?**

A. No.

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

A. Yes.

[40] Ibid.
[41] Staff/202, Cohen/8 (PacifiCorp's response to Staff DR 134).

CASE: UE 390
WITNESS: HEATHER COHEN

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

## STAFF EXHIBIT 201

## Witness Qualifications Statement

**June 9, 2021**

# 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 dockets: UG 388, UG 389, UG 390, UE 374 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 390
WITNESS: HEATHER COHEN

# PUBLIC UTILITY COMMISSION OF OREGON

# STAFF EXHIBIT 202

## Exhibits in Support Of Opening Testimony

June 9, 2021

**OPUC Data Request 6**

**Wholesale Power Purchases and Sales –** Please provide a narrative explanation of how wholesale power purchases are forecasted, including references to specific work papers provided to Staff by PacifiCorp, and cells within those work papers. Please also include a discussion of:

(a) How the node for each trade is chosen.

(b) For wholesale power purchase contracts already signed and included in the 2022 forecast, please provide a breakdown including:

i. Duration, including start and end date
ii. Size, detailing the MWh to be delivered in each hour.
iii. Price per MWh.
iv. When each contract was signed.
v. Please identify where items i-iv above are sited in the work papers.

(c) Please provide the proportion of forecasted purchases at each node and identify where this is sited in the work papers.

**Response to OPUC Data Request 6**

(a) The market hub, as well as the volume and time period for which a transaction is forecasted, is internal to the Generation and Regulation Initiative Decision Tool (GRID) for all system balancing transactions. There are no work papers as the decision is entirely internal to GRID and dictated by the optimization logic of GRID. GRID examines requirements, dispatchable resources, power and fuel prices, transmission constraints, and market capacity limitations to determine what is possible before settling on a dispatch plan that minimizes system costs while satisfying all system requirements and respecting all system constraints.

(b) Please refer to the confidential work papers provided in TAM Support Set 15 (15-calendar day work papers), specifically file "ORTAM22_STF (2012) FEB20 CONF.xlsx":

i. Please refer to column K and L in the work paper referenced above.
ii. Please refer to column R in the work paper referenced above.
iii. Please refer to column S in the work paper referenced above.
iv. Please refer to column M in the work paper referenced above.
v. Please refer to the preamble and responses to subparts i. through iv. above.

(c) The Company assumes this request is intended to ask for the proportion of volume at each market hub relative to total balancing purchases. Short-term firm (STF) volumes are not included as they are not forecasted in any meaningful sense, being actual transactions. Based on the foregoing assumption and clarification, the Company responds as follows:

Please refer to Confidential Attachment OPUC 6, which is sourced from the confidential work papers provided in TAM Support Set 1 (concurrent work papers), file "ORTAM22 NPC CONF.xlsm," tab "NPC," rows 534 through 545.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

**OPUC Data Request 11**

**OFPC -** With regard to the OFPC:

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

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

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

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

**Response to OPUC Data Request 11**

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

Docket UE 375 – the 2021 TAM (forecast calendar year 2021)
Docket UE 356 – the 2020 TAM (forecast calendar year 2020)
Docket UE 339 – the 2019 TAM (forecast calendar year 2019)

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

(a) The date of the official forward price curve (OFPC) used in the Company's filing is December 31, 2020. Please refer to the direct testimony of David G. Webb, page 6. Each TAM update will include the date of the OFPC used and supporting information as part of the work papers provided with each TAM update filing.

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

The July 2021 Update filing is expected to use the Company's March 31, 2021 OFPC. The Indicative filing, and the Final filing are expected to use prices from within the allowable range (nine days prior to the Indicative filing, and seven days prior to the Final filing).

(c) Please refer to the following information regarding PacifiCorp's OFPCs used in each TAM filing:

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

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

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

(d) Please refer to the Company's response to subpart (c) above. Please also refer to the Company's response to OPUC Data Request 12. The broker quotes used to produce PacifiCorp's OFPC on a given date are provided by the brokers on that specific date.

**OPUC Data Request 12**

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

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

(b) How the forecast treats different hours.

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

(d) How recent price spikes affect the forecast.

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

**Response to OPUC Data Request 12**

PacifiCorp's gas and electricity official forward price curves (OFPC) are developed from a combination of forward market prices on a given quote date and a long-term fundamentals-based price forecast. The first 37 months of the curve (inclusive of the spot month) are based upon an average of monthly broker quotes for the market period. Months 38 through 49 are an average of the previous year market forward price and the next year's fundamentals price forecast. A fundamentals-based price forecast is used exclusively beyond month 49. As such, the entire test period in this 2022 transition adjustment mechanism (TAM) proceeding, forecast calendar year 2022, is based entirely upon broker quotes. The broker quotes applied to the creation of OFPC are gathered from brokers on the date that the OFPC is produced (in the case of 2022 TAM initial/direct filing, the date was December 31, 2020). The Company considers these observed forward prices, and not price forecasts. Nodes/delivery points not quoted by brokers are estimated using a basis spread to a primary delivery point. Brokers quote power in on-peak and off-peak hours.

Note: the OFPC methodology described above produces monthly market prices differentiated by on-peak and off-peak schedules. In order to make those prices useful to the Generation and Regulation Initiative Decision Tool (GRID), the monthly prices are then shaped into an hourly series using the price scalars developed by the Company from observed historical hourly spot prices.

Please refer to the information provided above which incorporates the Company's responses to subparts (a) through (e) of this data request.

**OPUC Data Request 112**

**DA/RT**
PAC/100, Webb/22, lines 3-4 states that "the DA/RT adjustment calculated in this filing was calculated with the same methodology used in the 2021 TAM". Please provide the total amount of the adjustment on Oregon-allocated and system-wide basis as well as a reference to where that value is calculated in the work papers.

**Response to OPUC Data Request 112**

The Company has not performed the analysis required to quantify the overall impact of the day-ahead / real-time (DA/RT) adjustment to net power costs (NPC) for the 2022 transition adjustment mechanism (TAM) because the methodology is unchanged and has been in place since the 2016 TAM (docket UE 296). However, the confidential work papers supporting the direct testimony of Company witness, David G. Webb contain documentation supporting the calculation of the purchase and sale adders. Specifically, please refer to the Company's responses to TAM Support Set 2 (5-business day), file "ORTAM22w Dir_DA-RT Price Adder (2012) (CY2020-2023) CONF.xlsx," tab "Adders." In addition, the work paper supporting the application of those adders and the associated volumetric adjustment is available in the confidential work papers supporting Mr. Webb's direct testimony. Specifically, the Company's responses to TAM Support Set 1 (concurrent), file "ORTAM22 NPC DA-RT CONF.xslx." There is only one tab in that workbook, and the total incremental volume and expense/revenue by month, balancing authority area (BAA), and direction is available in cells AG147 through AJ158, and AG162 through AJ173, respectively.

**OPUC Data Request 134**

**OFPC Scalars**
IN PAC/100, Webb, 5-6, PacifiCorp references the official forward price curve (OFPC) as an input to GRID.

(a) Please provide all work papers detailing OFPC scalar methodology including all the underlying data from CAISO.

(b) Does PacifiCorp use two years of data to shape the scalars? If so, please provide references to specific work papers provided and cells within those work papers

**Response to OPUC Data Request 134**

(a) Please refer to Highly Confidential Attachment OPUC 134, file "Historical Hourly Price Scalars_2020 12 11 HIGHLY CONF" which provides PacifiCorp's hourly scalars calculation for the December 2020 official forward price curve (OFPC). Note: these hourly scalars will not reconcile perfectly to the values used to create the hourly prices used in the Generation and Regulation Initiative Decision Tool (GRID). The hourly prices in GRID include a monthly scalar component that cannot be provided because they include third-party proprietary information from the Inter-Continental Exchange (ICE) that PacifiCorp is contractually prohibited from sharing.

(b) Yes, the hourly scalars use two years of California Independent System Operator (CAISO) day-ahead hourly prices. Please refer to field "DelMo", cells C1 and BQ1 of the pivot-tables on tab "2yr-PACE" and tab "2yr-PACW" for the selection of the 24 months included in the hourly scalar calculation.

Highly Confidential information is designated as Highly Protected Information under the modified protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

CASE: UE 390
WITNESS: HEATHER COHEN

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 203

## Exhibits in Support
## Of Opening Testimony

**June 9, 2021**

**STAFF EXHIBIT 203**

**IS CONFIDENTIAL AND SUBJECT TO**

**PROTECTIVE ORDER NO. 21-086**

CASE: UE 390
WITNESS: NADINE HANHAN

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

## STAFF EXHIBIT 300

## Opening Testimony

**June 9, 2021**

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

A. My name is Nadine Hanhan. I am a Senior Utility Analyst employed in the Energy, Resources, and Planning 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/301.

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

A. The purpose of my testimony is to discuss PacifiCorp's (the Company) wheeling costs and revenues in the Transition Adjustment Mechanism (TAM).

**Q. Did you prepare any additional exhibits for this docket?**

A. Yes. I prepared the following additional Staff Exhibits:

- Staff/302: Confidential electronic exhibit on PacifiCorp wheeling costs.
- Staff/303: PacifiCorp's responses to Staff Data Requests (DRs) 40, 43, and 147.

**Q. How is your testimony organized?**

A. My testimony is organized as follows:

## WHEELING COSTS

**Q. Please describe the type of wheeling costs Staff investigated in the TAM.**

A. Staff reviewed the Company's workpapers[1] and confirmed that the Company includes in its net power cost calculation short-term transmission purchases (both firm and non-firm) with capacities based on the most recently available 48 months of transaction history. The Company has indicated that, to the extent these purchases reduce net power costs by more than the expense generated by their purchase, they would decrease NPC. The opposite would also be true.[2]

**Q. Please explain how the Company forecasts these costs.**

A. In general, the Company bases its wheeling cost forecasts on **[BEGIN CONFIDENTIAL]** [redacted].[3] **[END CONFIDENTIAL]** The Company relies heavily on these numbers to predict wheeling costs for the following year, but to Staff's knowledge, the Company does not appear to incorporate **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** to inform any of its wheeling cost forecasts.[4]

To estimate wheeling costs, the Company identifies particular "paths" across which it purchases transmission capacity. **[BEGIN CONFIDENTIAL]** [redacted]

[1] Staff/302 – (ORTAM22w Dir_Wheeling.xlsx, WheelingCosts tab).
[2] Staff/303, Hanhan/3 (PacifiCorp's response to Staff DR 43).
[3] Staff/302 – (ORTAM22w Dir_Wheeling.xlsx, SourceData tab).
[4] Staff/302 – (ORTAM22w Dir_Wheeling.xlsx, SourceData tab).

[redacted] **[END CONFIDENTIAL]** In many cases, these wheeling costs appear to be consistent. So, for example, if a particular "path" like **[BEGIN CONFIDENTIAL]** [redacted][5] **[END CONFIDENTIAL]**

**Q. Has Staff noticed any patterns over time?**

A. Based on the 2022 workpapers, many of the historic actuals seem to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in cost, with the Company forecasting **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** However, Staff did identify three particular transmission paths for which the Company should provide additional explanation as to why costs are forecasted to increase in its Reply Testimony.

**Q. What are the paths Staff has identified?**

A. The three "paths," or line items, in PacifiCorp's workpapers are the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

[5] Staff/302 – (ORTAM22w Dir_Wheeling.xlsx, WheelingCosts tab, row 56).

**Q. Please describe the concerns you have with the [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] path costs.**

A. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** path has been forecasted at **[BEGIN CONFIDENTIAL]** [redacted][6] **[END CONFIDENTIAL]** However, when Staff reviewed historic costs for this path, it appeared as though actual historic costs for this path have **[BEGIN CONFIDENTIAL]** [redacted] [7] **[END CONFIDENTIAL]** It is unclear why the Company is continuing to forecast **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** The differences in costs between 2019 and 2020 are summarized in a table below.

[6] Staff/302 – (ORTAM22w Dir_Wheeling.xlsx, WheelingCosts tab, row 121).
[7] See Table 1 for cost differences. This number is based on the percentage differences between February through June 2020 and February through June 2019.

*Table 1 - Differences in Wheeling Costs*[8]

**[BEGIN CONFIDENTIAL]**

| | 2019 | 2020 | Cost Difference | Percentage Decrease |
|---|---|---|---|---|
| February | [redacted] | [redacted] | [redacted] | [redacted] |
| March | [redacted] | [redacted] | [redacted] | [redacted] |
| April | [redacted] | [redacted] | [redacted] | [redacted] |
| May | [redacted] | [redacted] | [redacted] | [redacted] |
| June | [redacted] | [redacted] | [redacted] | [redacted] |

**[END CONFIDENTIAL]**

The average difference across these five months is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per month. Staff believes that a marked change in wheeling costs such as these should be reflected in the forecast. The Company should address these cost estimations and decreases in its Reply Testimony. The Company should also explain the purpose of this line item, what it is, and how the Company uses this service.

**Q. As a result of this information, do you recommend an adjustment?**

A. Yes, Staff recommends an adjustment on the wheeling cost input for the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** line item by **[BEGIN CONFIDENTIAL]** [redacted] **[END**

[8] For data behind this table, please see Staff/302, (ORTAM22w Dir_Wheeling.xlsx, SourceData tab, row 124).

**CONFIDENTIAL]** for the year of 2022 based on the fact that the data for this line item shows an ongoing lower cost. Staff is also open to the Company further informing the forecast based on 2020 actuals and data from 2021. This adjustment is consistent with the Company's forecast of the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** forecast, described below, where it relies on the most recent data for its forecast.

**Q. Please describe the concerns you have with the [BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL] wheeling costs.**

A. In general, Staff has noticed a significant increase in these costs over the course of the last couple years. Where this particular service used to decrease wheeling costs by a monthly average of **[BEGIN CONFIDENTIAL]** [redacted],[9] **[END CONFIDENTIAL]** it is now trending towards an increase in wheeling costs. Further, unlike the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** wheeling cost forecast, where the Company relies on older and higher cost historic data, for the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** forecast, the Company relies on more recent data, **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]** In its Reply Testimony, the Company should explain the inconsistency in these two approaches to forecasting costs,

[9] Staff/302 – (ORTAM22w Dir_Wheeling.xlsx, SourceData tab, row 67).

and should explain why the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** is demonstrating noticeable increases in costs over the past couple years. The Company should also explain the purpose of this line item, what it is, and how the Company uses this service.

**Q. Please describe the concerns you have with the [BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL] wheeling costs.**

A. With this particular line item, Staff has noticed a significant increase in costs over the past several years. Based on the Company's workpapers, this appears to be **[BEGIN CONFIDENTIAL]** [redacted][10] [redacted][11] **[END CONFIDENTIAL]** But now, it can reach costs of over **[BEGIN CONFIDENTIAL]** [redacted][12] **[END CONFIDENTIAL]** Staff believes this is a major contributing factor for the increase in Wheeling Costs between the 2021 TAM ($139,128,726) and the 2022 TAM ($147,601,542).[13]

Staff has no recommended adjustment at this time for this portion of wheeling costs. However, Staff is interested to know the reasons behind the increase in these costs. In the Company's Reply Testimony, the Company should address these significant increases over time, and why the Company is relying on this

[10] Staff/302 – (ORTAM22w Dir_Wheeling.xlsx, WheelingCosts tab.)
[11] Staff/303, confidential attachment (PacifiCorp's response to Staff DR 147, electronic attachment OPUC 147-1, WheelingCosts tabs for years 2017-2021).
[12] Staff/302 – (ORTAM22w Dir_Wheeling.xlsx, SourceData tab, row 26).
[13] PAC/101, Webb/1.

service more heavily in recent years. PacifiCorp should also illustrate the need for including this expense in power costs.

**Q. Although wheeling revenues are addressed in the Company's base rates, are there potential implications for future NPC filings related to wheeling revenues in the Energy Imbalance Market (EIM)?**

A. Yes. In UE 375, Staff's concern was that EIM entities, such as PacifiCorp, who facilitate wheeling power do not currently receive any benefit for doing so. Staff indicated it would continue to monitor this issue.[14]

Staff submitted discovery requesting PacifiCorp to explain any developments in this area. The Company indicated that the California Independent System Operator (CAISO) began a process called the Extended Day-Ahead Market (EDAM), within which it would explore the issue of monitoring wheel-through volumes.[15] This could assess whether there would be a potential future need to for a market solution to address the equitable sharing of wheeling benefits.[16] However, PacifiCorp also explained that "CAISO has paused the EDAM initiative since July 2020."[17] As a result, there appear to be no developments in this area.

Although the Commission declined to include general wheeling revenues in PacifiCorp's annual TAM filing in the final order related to its General Rate

[14] UE 375 - Staff/200, Enright/47-49.[15] Staff/303, Hanhan/1 (PacifiCorp's response to DR 40).
[15] Staff/303, Hanhan/1 (PacifiCorp's response to DR 40).
[16] Staff/303, Hanhan/1 (PacifiCorp's response to DR 40).
[17] Staff/303, Hanhan/1 (PacifiCorp's response to DR 40).

Case,[18] Staff intends to continue to monitor the developing issue of EIM or EDAM wheeling revenues.

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

A. Yes.

[18] *In re PacifiCorp*, OPUC Docket No. UE 374, Order No. 20-473 at 130 (Dec. 18, 2020).

CASE: UE 390
WITNESS: NADINE HANHAN

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 301

# Witness Qualifications Statement

**June 9, 2021**

**WITNESS QUALIFICATIONS STATEMENT**

| | |
|---|---|
| NAME: | Nadine Hanhan |
| EMPLOYER: | Public Utility Commission of Oregon |
| TITLE: | Senior Utility Analyst, Transmission & Distribution<br>Energy Resources and Planning Division |
| ADDRESS: | 201 High Street SE. Suite 100<br>Salem, OR. 97301 |
| EDUCATION: | Bachelor of Arts in Economics, CSUSB (2010)<br><br>Bachelor of Arts in Philosophy, CSUSB (2010)<br><br>Master of Science in Applied Economics, Oregon State University (2015) |
| EXPERIENCE: | I have nine years of utility regulation experience. For four years, I worked at the Citizens' Utility Board of Oregon as a ratepayer advocate for residential customers. While there, I provided analysis, expert testimony, and comments in a variety of dockets with topics including gas and electric integrated resource planning, solar resource value, renewable contribution to capacity, smart grids, power costs, natural gas hedging, and electric vehicles. Cases I worked on at CUB include, but are not limited to: UE 264, UE 296, UM 1505, UM 1657, UM 1667, UM 1675, UM 1716, UM 1719, UM 1746, LC 55, LC 56, LC 57, LC 58, LC 59, LC 60, LC 61, LC 62, and LC 63.<br><br>For almost five years I have been employed at the OPUC, where I have provided analysis, testimony, comments, and support for other Staff in a variety of dockets and proceedings including smart grids, integrated resource plans, voluntary green energy tariffs, electric vehicles, renewable portfolio standard rules, renewable portfolio standard compliance, certificates of public convenience and necessity, rulemakings, and transmission planning, among others. Cases I have worked on at the OPUC include, but are not limited to: ADV 901, AR 609, AR 610, AR 626, AR 638 LC 62, LC 64, LC 68, LC 70, LC 71, LC 73, LC 74, LC 75, LC 76, PCN 2, PCN 4, UE 347, UE 348, UE 355, UM 1810, UM 1811, UM 1815, UM 1846, UM 1847, and UM 2031. |

CASE: UE 390
WITNESS: NADINE HANHAN

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 302

## Exhibits in Support
## Of Opening Testimony

**June 9 2021**

**STAFF ELECTRONIC EXHIBIT 302**

**IS CONFIDENTIAL AND SUBJECT TO**

**PROTECTIVE ORDER NO. 21-086**

CASE: UE 390
WITNESS: NADINE HANHAN

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 303

## Exhibits in Support
## Of Opening Testimony

**June 9, 2021**

UE 390 / PacifiCorp
May 7, 2021
OPUC Data Request 40

**OPUC Data Request 40**

**Transmission, wheeling -** Regarding EIM transactions, where the Company facilitates wheel throughs but receives no direct financial benefit:

(a) Has the Company engaged with CAISO regarding this matter? If yes, please provide a summary of the content of those communications to date.

(b) If the Company has conducted analysis or tracking of EIM wheel through in its territory, please provide a copy of this analysis and a narrative explanation of the results.

(c) If the Company has conducted analysis quantifying the value lost through EIM wheel-throughs in its territory, please provide a copy of this analysis and a narrative explanation of the results.

(d) If the Company has an expectation of how wheel through transfers will be treated in the potential extended day-ahead market, or has taken a position on this issue, please provide a narrative explanation of this.

**Response to OPUC Data Request 40**

(a) Starting in October 2019, the California Independent System Operator (CAISO) has engaged with the energy imbalance market (EIM) entities in a stakeholder process called the Extended Day-Ahead Market (EDAM). In its initial issue paper on this effort, CAISO stated that it is "committed to monitoring the wheel-through volumes to assess whether, after the addition of new EIM entities, there is a potential future need to pursue a market solution to address the equitable sharing of wheeling benefits". This quotation is provided at the bottom of page 9 in the document located at the following CAISO website link: IssuePaper-ExtendedDayAheadMarket.pdf (caiso.com). CAISO has paused the EDAM initiative since July 2020 with the latest overview of the proposed topic bundles to be addressed in the future contained in the following document:

StrawProposal-ExtendedDay-AheadMarket-BundleOneTopics.pdf (caiso.com).

A date for when this initiative will be resumed has not yet been determined by CAISO.

(b) The CAISO publishes, on a quarterly basis, its Western EIM Benefits Report. Since Q3 2017, the quarterly benefits report has included balancing authority area (BAA) specific wheel through volumes for each month. The data, calculation methodology and narrative descriptions are publicly available and can be accessed by utilizing the following website link, specifically the section on "Wheel Through Transfers" in each quarterly report:

Western EIM - Benefits

(c) PacifiCorp has not conducted any analysis on this topic.

(d) The EIM entities have jointly presented on transmission elements of the EDAM market design. A narrative description of the position of the EIM entities (which includes PacifiCorp) on this issue, inclusive of wheel through transfers, is provided in the following presentation that is publicly available at the following location:

Presentation-ExtendedDay-AheadMarket-TransmissionProvision-EIMEntities.pdf (caiso.com).

UE 390 / PacifiCorp
May 7, 2021
OPUC Data Request 43

**OPUC Data Request 43**

**Transmission, wheeling –** Does PacifiCorp incorporate costs from bilateral transmission capacity purchases into power costs? For example, if PacifiCorp needs to purchase additional transmission capacity on OASIS on a short-term basis, is this reflected in power costs?

(a) If yes, how does PacifiCorp forecast these purchases in its annual power cost update? Please also explain how this affects power costs.

(b) If yes, what is the total cost of these purchases? Please reference the appropriate work papers in your answer if available, with cell formulae intact.

(c) If these purchases are not reflected in power costs, please explain why they are not included.

**Response to OPUC Data Request 43**

Yes.

(a) Short-term transmission purchases (both firm and non-firm) are modeled in the Generation and Regulation Initiative Decision Tool (GRID) with capacities based on the most recently available 48 months of transaction history. To the extent that these purchases reduce net power costs (NPC) by more than the expense generated by their purchase, they would decrease NPC. The opposite would also be true.

(b) Please refer to the confidential work papers provided with the Company's responses to TAM Support Set 2 (5-business day), specifically file "ORTAM22w Dir_Wheeling.xlsx."

(c) Not applicable.

UE 390 / PacifiCorp
June 1, 2021
OPUC Data Request 147

**OPUC Data Request 147**

**Transmission, wheeling**
Regarding wheeling costs as represented in ORTAM22w Dir_Wheeling.xlsx:

(a) Please provide these forecasted wheeling costs for each of the past 5 years.

(b) Please also provide these actual wheeling costs for each of the past 5 years.

(c) Please provide any additional forecasted wheeling costs or expenses (as referenced in data request 144) for the past five years.

(d) Please provide any additional actual wheeling costs or expenses (as referenced in data request 144) for the past five years.

**Response to OPUC Data Request 147**

The Company assumes that the reference to “data request 144” is intended to be a reference to OPUC Data Request 144.” Based on the foregoing assumption, the Company responds as follows:

The Company assumes that the reference to “forecasted wheeling costs for each of the past 5 years” is intended to reference the forecasted wheeling expenses included in each of the Company’s previous transition adjustment mechanism (TAM) proceedings, namely:

Docket UE 375 – 2021 TAM for forecast calendar year 2021
Docket UE 356 – 2020 TAM for forecast calendar year 2020
Docket UE 339 – 2019 TAM for forecast calendar year 2019
Docket UE 323 – 2018 TAM for forecast calendar year 2018
Docket UE 307 – 2017 TAM for forecast calendar year 2017

(a) Referencing confidential work paper “ORTAM22w Dir_Wheeling” in this 2022 TAM, please refer to Confidential Attachment OPUC 147-1, which provides copies of the equivalent confidential work papers of wheeling expenses as forecasted in the Company’s five previous TAM proceedings, as listed above.

(b) Please refer to Attachment OPUC 147-2, which provides actual wheeling expenses (FERC Account 565) for calendar years 2016 through 2020.

(c) The only additional forecasted wheeling costs are mentioned in subpart (d) of the Company’s response to OPUC Data Request 144. Those costs are calculated by the Generation and Regulation Initiative Decision Tool (GRID) and are available in the net power costs (NPC) reports themselves, which were provided in the Company’s response to OPUC Data Request 15 (tab “NPC” section labeled

"Wheeling & U. of F. Expense").

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

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

**STAFF ATTACHMENT TO STAFF EXHIBIT 303, (PACIFICORP'S RESPONSE TO STAFF DR 147, ELECTRONIC ATTACHMENT OPUC 147-1)**

**IS CONFIDENTIAL AND SUBJECT TO**

**PROTECTIVE ORDER NO. 21-086**

CASE: UE 390
WITNESS: BRIAN FJELDHEIM

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

## STAFF EXHIBIT 400

## OpeningTestimony

## June 9, 2021

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

A. My name is Brian Fjeldheim. I am a Senior Financial 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/401.

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

A. The purpose of my testimony is to describe Staff's position on the following issues: Gas and fuel oil costs, and gas optimization.

**Q. Did you prepare any additional exhibits for this docket?**

A. Yes. I prepared the following exhibits:

| | |
|---|---|
| Staff/401 | Witness Qualification Statement. |
| Staff/402 | Non-confidential PacifiCorp responses to Staff data requests (DRs). |
| Staff/403 | Confidential PacifiCorp response to Staff DR 78. |

**Q. How is your testimony organized?**

A. My testimony is organized as follows:

## ISSUE 1, GAS AND FUEL OIL COSTS

**Q. Please summarize Staff's review of PacifiCorp's natural gas and fuel oil costs included in the 2022 Transition Adjustment Mechanism (TAM).**

A. Staff's review focused primarily on the portions of testimony and supporting exhibits provided by Mr. Webb (PAC/100-107). In that testimony, Mr. Webb addresses updated natural gas cost inputs used in the Company's Generation and Regulation Initiative Decision Tools (GRID) model.

**Q. Please describe the change in PacifiCorp's natural gas costs between the 2021 and the 2022 TAM.**

A. In the initial 2022 TAM filing, the Company projects total system natural gas costs to increase $56 million[1] (19.6 percent)[2] over the 2021 TAM. On an Oregon allocated basis, this translates to a $14.8 million (20.9 percent) increase. The increased gas expense is due to 3,156 gigawatt hours (GWh) of additional total system natural gas thermal generation, a 28.7 percent increase over the prior TAM,[3] which is being driven by lower natural gas prices, as shown in Confidential Figure 1 on the following page. On a per megawatt hour (MWh) basis, PacifiCorp's 2022 TAM natural gas expense is decreasing by $1.82/MWh, dropping from $25.79/MWh to $23.97/MWh, a 7.1 percent decrease.[4]

[1] PAC/100, Webb/18, Figure 2.
[2] PAC/101, Webb/1, lines 27-29.
[3] PAC/100, Webb/21, lines 8-9.
[4] PAC/100, Webb/21, lines 5-7.

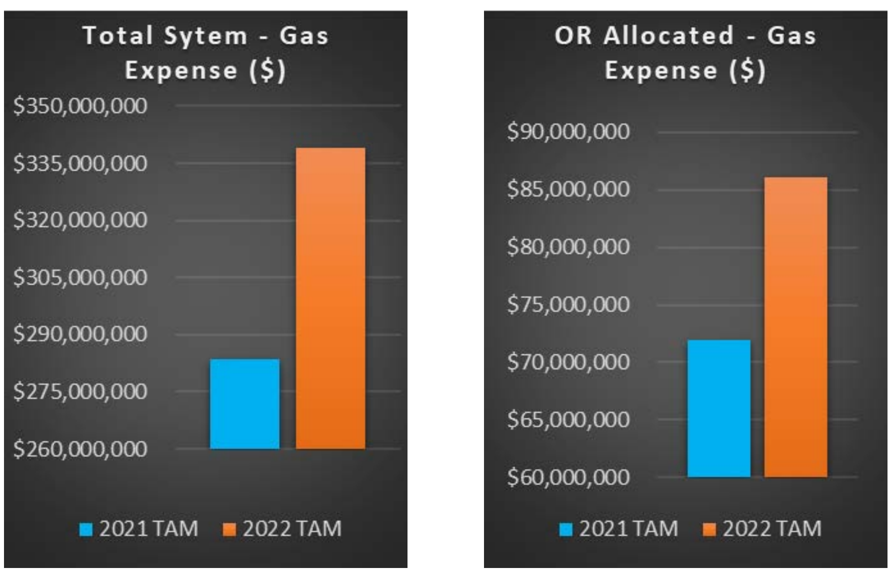
*Figure 1 - Total System and Oregon Gas Generation (MWh)*[5]

**[BEGIN CONFIDENTIAL]**

[redacted]

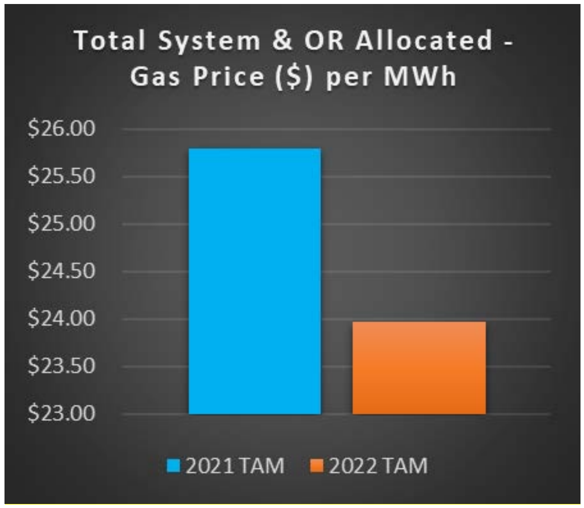
**[END CONFIDENTIAL]**

*Figure 2 - Total System and Oregon Gas Expense ($)*[6]




[5] PAC confidential Excel workpaper "ORTAM Testimony Support CONF", tab "Figure 2 - Table 2 NPC Reconc", row 11.
[6] PAC/101, Webb/1.

*Figure 3 - Total System and Oregon Allocated Gas Price ($/MWh)*[7]




**Q. What data source(s) does PacifiCorp use for pricing natural gas in the TAM?**

A. The Company used its official forward price curve (OFPC) dated December 31, 2020 to derive the natural gas prices used in the 2022 TAM.[8] In this filing, the OFPC natural gas prices are based upon 12 months of broker quotes and are required to be within 5 percent of the broker average.[9] Additionally, the Company relied upon natural gas futures pricing published in the Wall Street Journal (WSJ).[10]

[7] PAC/100, Webb, 21 at line 7.
[8] Staff/402, Fjeldheim/2.
[9] Staff/402, Fjeldheim/1 and Confidential Staff/403, Fjeldheim/1-2.
[10] PAC Confidential Excel workpaper "Fuel Prices and Index Fcst Master – Confidential," Tab "Natural Gas Futures," rows 39-50. Staff notes that the Company's workpaper appears in contradiction with its response to Staff DR 90, in which the Company states that the WSJ has no bearing on natural gas prices in the 2022 TAM. See Staff /402, Fjeldheim/4.

**Q. Did Staff have difficulties verifying the Company's natural gas pricing in this case?**

A. Yes. In the Company's responses to Staff DRs 90 and 91, the Company stated it does not rely upon WSJ data to support its OFPC pricing for natural gas.[11] However, in the Company's initial filing, it provided a Confidential Excel workpaper titled "Fuel Prices and Index Fcst Master – Confidential." On tab "Natural Gas Futures", row 2 contains an active hyperlink that is referenced as "Source" that leads to published WSJ natural gas futures pricing data. Given the information in this workpaper, the Company's reply that it uses the Henry Hub index for coal supply pricing related to the Cholla plant appears to be incorrect, as Henry Hub is a major commodity pricing, trading, and shipping hub for natural gas supplies located in Erath, Louisiana. Further, it is unclear to Staff how PacifiCorp uses Henry Hub to price coal contracts.[12]

**Q. Does Staff propose an adjustment for natural gas pricing?**

A. No, not at this time.

**Q. Does PacifiCorp include fuel oil costs in the TAM?**

A. After reviewing the Company's initial filing, including testimony provided by Mr. Webb and several supporting workpapers,[13] Staff did not identify any fuel oil costs in this filing.

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[11] Staff/402, Fjeldheim/4-5.

[12] CME Group – Understanding Henry Hub, accessed here: https://www.youtube.com/watch?v=XAJcrk0RmYs

[13] PacifiCorp Confidential Excel workpapers "ORTAM22 NPC CONF", "ORTAM22 Testimony Support CONF", "ORTAM22 Dir_Fuel Price (2012) CONF," and "Fuel Price and Index Fcst Master – Confidential."

**Q. Does PacifiCorp include fuel oil pricing in the TAM?**

A. It appears the Company uses fuel oil pricing as a proxy market price indicator for other fossil fuels, such as natural gas and possibly coal. In the Company's confidential Excel workpaper "Fuel Price and Index GCST Master – Confidential," there are several worksheets that contain fuel oil futures pricing. However, Staff did not find any evidence that the Company incurred fuel oil costs in the 2021 TAM nor did Staff find evidence of projected fuel oil costs included in the 2022 TAM filing.

## ISSUE 2, GAS OPTIMIZATION

**Q. What is gas optimization?**

A. Gas optimization can be defined in a number of different ways. One definition of gas optimization is the economic use of gas resources. For example, assume an electric utility has several gas fired generators of varying efficiency. If the utility dispatches its electric generators in order of gas or operational efficiency, fueling the most efficient generators first with the least expensive fuel, with the least efficient generators dispatched last using the most expensive fuel, this would be a form of gas optimization. This is because utility customers would receive maximized energy output at the lowest fuel price point. This form of optimization generally occurs when a utility uses less than 100 percent of its generating capacity.

**Q. Is there another definition commonly used?**

A. Yes. Another definition of gas optimization involves price arbitrage, whereby an entity buys gas or gas contracts at a lower price from one market and then sells the gas or gas contracts for a profit in a different market(s). This form of optimization is more likely to occur when an entity has the opportunity to leverage recurring market trends, such as seasonality of electric generation or gas usage for space heating.

**Q. Can you please provide an example?**

A. Yes. Assume a utility company has a gas storage facility and can access multiple gas supply markets, the utility can purchase gas during times of the year when gas prices are low, or possibly from a market with lower priced gas, and then store the gas. The utility can use or resell this gas during times of the year when seasonal prices are high, or when there is a marginal gas price difference between gas markets. However, if a utility were to purchase gas solely on the basis of later reselling it at a higher price and does not intend to use it to serve customer load, this would be considered speculative behavior and would pose a risk to ratepayers.

Because a utility is obligated to meet ratepayer load requirements, and because there can be significant variability in seasonal weather in the Pacific Northwest, in theory, a utility should not need to utilize the full capacity of its system year round. However, because utilities need to have the underlying infrastructure to serve peak load, ratepayers are subject to paying for equipment or fuel that goes unused. When a utility is able to safely and reliably meet customer load while maintaining sufficient fuel or reserve dispatch capacity, the remaining generating capacity and/or unused fuel can be sold into the market for the economic benefit of the utility and ratepayer.[14]

**Q. Does PacifiCorp engage in natural gas optimization?**

A. Yes. The Company states:

> The Company looks to optimize its natural gas resources while serving its system obligations. The Company dispatches its natural gas resources based on the market economics at the time of balancing. The Company

[14] As part of Northwest Natural Gas Company's (NW Natural) annual purchased gas adjustment (PGA), NW Natural sells excess gas supplies that would otherwise go unused into markets with higher gas prices, and returns the bulk of these sales profits to ratepayers in the form of a February bill credit. https://www.nwnatural.com/about-us/the-company/newsroom/2021-or-feb-bill-credits

> utilizes all system resources to provide the most efficient economic solution to meet system requirements.[15]

**Q. Does PacifiCorp engage in natural gas price arbitrage?**

A. Yes. The Company states:

> The Company transacts in the forward natural gas markets for the purpose of serving load. When optimizing natural gas if favorable market conditions exist PacifiCorp will engage in natural gas price arbitrage for the benefit customers. The Company hedges natural gas supply in the forward markets based on anticipated fuel requirements. At the time of delivery, market conditions may change where one or more of the plants result in different market spark spreads allowing the Company to economically buy or sell additional natural gas while still meeting system needs from other resources, either Company owned resources or from the power market.[16]

**Q. Does PacifiCorp share optimization proceeds from natural gas price optimization and/or arbitrage with Oregon ratepayers?**

A. Staff was unable to determine whether the Company shares optimization proceeds with ratepayers. In its response to Staff DR 95, the Company did not elaborate as to who benefits from arbitrage activity. Additionally, Staff did not identify within the Company's workpapers a reference to optimization proceeds

[15] Staff/402, Fjeldheim/6.
[16] Staff/402, Fjeldheim/7.

being returned to ratepayers or being used to offset future expenses that will be passed on to ratepayers.

**Q. Does Staff propose an optimization adjustment in this round of testimony?**

A. No. However, Staff requests that the Company respond with an explanation of how gas optimization benefits are shared with customers, if at all. If no sharing occurs, Staff recommends the Company provide a proposal to share optimization savings between ratepayers and shareholders. This sharing of optimization savings should recognize that customers are paying for the plant that allows optimization activities.

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

A. Yes.

CASE: UE 390
WITNESS: BRIAN FJELDHEIM

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 401

# Witness Qualifications Statement

# June 9, 2021

**WITNESS QUALIFICATION STATEMENT**

| | |
|---|---|
| NAME: | Brian Fjeldheim |
| EMPLOYER: | Public Utility Commission of Oregon |
| TITLE: | Senior Financial Analyst<br>Energy Rates, Finance and Audit Division |
| ADDRESS: | 201 High Street SE. Suite 100<br>Salem, OR. 97301 |
| EDUCATION: | Bachelor of Science, Business Accountancy<br>Regis University, Denver, CO<br><br>Bachelor of Science, Aviation Technology<br>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 Energy, Rates and Finance 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 in the following dockets: Cascade Natural Gas – UG 347, Avista Utilities – UG 366, NW Natural – UG 388, PacifiCorp – UE 374, Avista Utilities – UG 389, and Cascade Natural Gas – UG 390.<br><br>I have eight 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 390
WITNESS: BRIAN FJELDHEIM

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 402

## Exhibits in Support
## Of Opening Testimony

**June 9, 2021**

UE 390 / PacifiCorp
May 10, 2021
OPUC Data Request 78

**OPUC Data Request 78**

**2022 TAM updated inputs**
In PAC/100, Webb/5-6, the Company references updated inputs for natural gas, official forward price curve (OFPC) for natural gas, and fuel expenses. Please provide:

(a) The name of each work paper(s) using these inputs;

(b) The location within each workpaper where these inputs are used;

(c) Documentation supporting how the inputs are derived, and

(d) The individual electronic workpaper(s).

**Response to OPUC Data Request 78**

(a) Please refer to the confidential work papers provided with the Company's response to TAM Support Set 2 (5-business day), specifically file "ORTAM22w Dir_Market Price Index (2012) CONF."

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

(c) PacifiCorp's natural gas and electricity official forward price curves (OFPC) are developed from a combination of forward market prices on a given quote date and a long-term fundamentals-based price forecast. The first 37 months of the curve are based upon an average of monthly broker quotes for the market period. Months 38 through 49 are an average of the previous year market forward price and the next year's fundamentals price forecast. A fundamentals-based price forecast is used exclusively beyond month 49. As such, the entire test period in this 2022 transition adjustment mechanism (TAM), calendar year 2022, is based upon broker quotes. The prices used in the TAM are required to be within 5 percent of the broker average. Please refer to Confidential Attachment OPUC 78 to observe a comparison of the OFPC to the broker quotes received by Company.

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

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

For PacifiCorp's Confidential response to Staff DR 78,

see Staff/403, Fjeldheim

UE 390 / PacifiCorp
May 10, 2021
OPUC Data Request 88

**OPUC Data Request 88**

**Natural gas pricing**
What data source(s) did PacifiCorp use for pricing natural gas in the 2022 TAM?

**Response to OPUC Data Request 88**

The Company used its December 31, 2020 official forward price curve (OFPC) for the natural gas prices used in the 2022 transition adjustment mechanism (TAM). Those prices were based on broker quotes, as explained in the Company's response to OPUC Data Request 78.

UE 390 / PacifiCorp
May 10, 2021
OPUC Data Request 90

**OPUC Data Request 90**

**Natural gas pricing**
For the Excel work paper titled "Fuel Price and Index Fcst Master – Confidential," please provide the date the Company accessed the Wall Street Journal (WSJ) to generate the natural gas futures pricing in tab "Natural Gas Futures."

**Response to OPUC Data Request 90**

The Henry Hub index, as referenced in file "Fuel Price and Index Fcst Master – Confidential," was related to the coal supply agreement (CSA) for the Cholla plant. PacifiCorp has closed its operations of the Cholla plant and the index has no bearing on the 2022 transition adjustment mechanism (TAM).

UE 390 / PacifiCorp
May 10, 2021
OPUC Data Request 91

**OPUC Data Request 91**

**Natural gas pricing**
Besides WSJ quotes for Henry Hub natural gas futures, does the Company use pricing data that is more closely aligned to the Pacific Northwest region to forecast natural gas futures (e.g. AECO, Sumas, or Rockies natural gas)? If no, please provide a detailed explanation of the reasons why.

**Response to OPUC Data Request 91**

Please refer to the Company's response to OPUC Data Request 90.

UE 390 / PacifiCorp
May 10, 2021
OPUC Data Request 94

**OPUC Data Request 94**

**Natural gas optimization**
Does PacifiCorp engage in natural gas optimization? If yes, please provide a summary overview of the Company's gas optimization plan.

**Response to OPUC Data Request 94**

Yes. The Company looks to optimize its natural gas resources while serving its system obligations. The Company dispatches its natural gas resources based on the market economics at the time of balancing. The Company utilizes all system resources to provide the most efficient economic solution to meet system requirements.

UE 390 / PacifiCorp
May 10, 2021
OPUC Data Request 95

**OPUC Data Request 95**

**Natural gas optimization**
Does PacifiCorp engage in price arbitrage as part of its gas optimization plan? If yes, please provide:

(a) A summary overview of the Company's arbitrage strategy.

(b) An explanation of how the Company protects ratepayers from commodity price speculation.

**Response to OPUC Data Request 95**

The Company transacts in the forward natural gas markets for the purpose of serving load. When optimizing natural gas if favorable market conditions exist PacifiCorp will engage in natural gas price arbitrage for the benefit customers

(a) The Company hedges natural gas supply in the forward markets based on anticipated fuel requirements. At the time of delivery, market conditions may change where one or more of the plants result in different market spark spreads allowing the Company to economically buy or sell additional natural gas while still meeting system needs from other resources, either Company owned resources or from the power market.

(b) The Company does not engage in price speculation.

CASE: UE 390
WITNESS: BRIAN FJELDHEIM

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 403

## Exhibits in Support
## Of Opening Testimony

**June 9, 2021**

**STAFF EXHIBIT 403**

**IS CONFIDENTIAL AND SUBJECT TO**

**PROTECTIVE ORDER NO. 21-086**

Docket No. UE 390

OR UE 390
OPUC 9

12/31/2020 FPC to Brokers Comparison
PROTECTED INFORMATION
SUBJECT TO GENERAL PROTECTIVE ORDER

Confidential Attachment OPUC 9

[redacted]



CONFIDENTIAL

12/31/2020 FPC to Brokers Comparison
PROTECTED INFORMATION
SUBJECT TO GENERAL PROTECTIVE ORDER

Confidential Attachment OPUC 9

[redacted]

CASE: UE 390
WITNESS: KATHY ZARATE

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 500

# Opening Testimony

# June 9, 2021

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

A. My name is Kathy Zarate. I am a Utility Economist employed in the Energy Economic Analysis 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/501.

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

A. The purpose of my testimony is to summarize and make recommendations on certain issues regarding PacifiCorp's 2022 Transition Adjustment Mechanism (TAM) filling, Docket No. UE 390.

**Q. Did you prepare any additional exhibits for this docket?**

A. Yes. I prepared

- Exhibit Staff/501: Witness Qualification
- Exhibit Staff/502: PacifiCorp's non- confidential Reponses to Staff Data Request Nos. 22 and 36.
- Exhibit Staff/503: PacifiCorp's Confidential Responses to Staff Data Request Nos. 23 and 114

**Q. How is your testimony organized?**

A. My testimony is organized as follows:

## ISSUE 1, STANDARD INPUTS

**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 Staff reviewed are heat rates, forced and scheduled maintenance outages, and minimum operating levels.

**Q. How did Staff review these issues?**

A. Staff inspected PacifiCorp's values for standard inputs by reviewing PacifiCorp's testimony and responses to Staff Data Requests. Staff asked the Company to explain its process and reasoning for determining heat rates, operating levels and outage schedules.

**Q. What are Staff's observations regarding the Company's response?**

A. Staff finds the maintenance planning and discussion offered by the Company to be reasonable and consistent with past filings.

The values for the standard inputs for forced outages, heat rates and minimum operating levels appear reasonable and the Company offered that 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 also stated that it schedules the planned 2022 outages to avoid forecasted peak system needs, for instance, peak summer obligations and peak winter obligations.[1]

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[1] Staff/502,Zarate/2 (pacifiCorp's confidential response to Staff DR 36)

**Q. What is Staff's recommendation for this issue?**

A. Staff recommends no adjustments.

## ISSUE 2, OTHER REVENUES

**Q. Please provide background on Other Revenues included in TAM rates.**

A. In Docket No. UE 216, PacifiCorp's 2011 TAM, Staff raised the issue of a mismatch between updating costs and revenues in a TAM. Specifically, Staff argued that if the Company is allowed to include, or update, the costs associated with new resources, contracts, and existing facilities for services it provides to third parties in stand-alone power cost filings, then the Company should also include revenues similarly gained.[2] The Commission, in Order No. 10-363 in Docket No. UE 216, adopted a stipulation in which the parties agreed that in future stand-alone TAM filings, the Company would include an update to Other Revenues related to net power costs.

The Company reports the update to Other Revenues as the difference from the baseline levels specified in its most recent general rate case.

**Q. How does PacifiCorp propose to treat Other Revenues in the 2022 TAM?**

A. Because Other Revenues were incorporated into base rates in the Company's 2020 General Rate Case (with a test year of 2021), Schedule 205 rates were set to zero.[3] As such, the Company has not proposed an adjustment to Schedule 205 rates.

[2] Staff/502,Zarate/4 (PacifiCorp's confidential response to Staff DR 34)
[3] PAC/100, Webb/3-4.

**Q. What is Staff's recommendation for this issue?**

A. Staff has no adjustment to PacifiCorp's Schedule 205 at this time. In future stand-alone filings, Staff expects the Company's proposed Schedule 205 rates to reflect forecast changes in Other Revenues in accordance with the policy established in UE 216.

## ISSUE 3, CONSUMER OPT-OUT CHARGE

**Q. What is PacifiCorp's Consumer Opt-Out Charge?**

A. As PacifiCorp witness Mr. Webb states, "the Consumer Opt-Out charges is a transition adjustment applicable to the Company's five-year direct access program and is intended to recover transitions costs incurred during years six through 10 following the departure of the direct access load."[4]

**Q. How is the Consumer Opt-Out Charge calculated**?

A. For the first five years, the Direct Access customer pays two costs. First, the customer pays the actual Schedule 200 rates as would any other PacifiCorp retail customer. Those Schedule 200 rates could change annually during the five-year transition period (which can include incremental generation). Second, the Customer pays the Consumer Opt-Out Charge, which is a forecast of Schedule 200 costs for years six through 10, which uses Schedule 200 costs at the time of departure and then escalates those costs using an inflation escalator. PacifiCorp then takes these costs and reduces them back to calculate a levelized payment.

**Q. Has PacifiCorp made any proposed changes to the calculation of the Consumer Opt-Out Charge relative to the stipulation filed in the 2020 TAM**?

[4] PAC/100, Webb/33-34.

A. No. PacifiCorp's calculation of the Consumer Opt-Out Charge in the 2022 TAM is consistent with the stipulation filed in the 2020 TAM, of which Staff was a signatory.[5]

**Q. Does Staff have a recommended change to the Consumer Opt-Out Charge in this case?**

A. Not at this time. Staff will consider and address specific changes proposed by intervenors, if applicable, in Staff's cross-answering testimony.

[5] *In re PacifiCorp*, OPUC Docket No. UE 356, Order No. 19-351 at Appendix A, pg. 10 (Oct. 30, 2019).

## ISSUE 4. QUALIFYING FACILITIES (QF)

**Q. Please describe Qualifying Facilities (QFs) and how costs associated with QFs are incorporated in TAM rates**.

A. Under PURPA, the Public Utility Regulatory Policies Act of 1978, investor-owned utilities are required to purchase power from Qualifying Facilities (QFs) using rates established by the state regulatory commissions, like the Oregon PUC. QF costs allocated to Oregon are included in NPC using the same methodology as that established in the 2018 TAM, Docket No. UE 323, where the Commission adopted CUB's proposal for the treatment of QF costs in the TAM. In UE 323, the Commission directed PacifiCorp to calculate and apply a Contract Delay Rate (CDR) based on a three-year history of delays for new QFs. The Commission-adopted methodology also includes weighting the CDR by QF size to more accurately reflect the rate impact of forecast errors.

**Q. Could you explain how the CDR works?**

A. Yes. As stated above, the Commission adopted the CDR adjustment in Docket UE 323:

> For the 2019 TAM we direct the company to weight the CDR by QF size to more accurately reflect the rate impact of forecast errors. We do not adopt PacifiCorp's proposal to weight the CDR by QF size in the 2018 TAM because the record in this proceeding is not clear on the steps of that calculation. We agree with CUB that PacifiCorp should use a three-year rolling average of delays to produce a CDR, apply this CDR to the CODs reported in the indicative update, and adjust the

TAM year forecast based on the delay days within the TAM year. Thus, as CUB explains, a CDR adjustment to a contract that was forecast to begin on November 15, (before the TAM year) would only affect the TAM forecast if the CDR is greater than 45 days. Similarly, a CDR adjustment to a contract that was scheduled to have a COD on December 15 (during the TAM year) would only affect the first 16 days of operation, because those are the only days included in the TAM.[6]

**Q. Please explain how the calculation works in this TAM.**

A. In this TAM, the 2018, 2019 and 2020 TAM fillings are each reviewed in terms of the final forecast for the commercial operation date of new QFs, and those dates are compared to when the new QFs actually began operation. Whatever the actual average day delay (not weighted by MW) is in the commercial operation date, from forecast to actual, is then applied to the projected new QFs coming on line for this year's TAM filling. A new QF projected to come on-line before the TAM year would only affect the forecast year if the three-year average-days delay, when added to the projected COD, would extend into the TAM year.[7]

**Q. Did PacifiCorp make a CDR Adjustment for 2022?**

A. No, PacifiCorp did not make a CDR Adjustment for 2022 because no new QFs are projected to come on-line in 2022. In addition, given that the new non-

[6] *In re PacifiCorp*, OPUC Docket No. UE 323, Order No. 17-444 (Nov. 1, 2017).
[7] *Id.*

Oregon QFs are allocated situs, the CDR should not impact Oregon for QFs not located in Oregon.

**Q. Is there anything that could be different in the manner to which PURPA purchased power costs are allocated across PacifiCorp's state jurisdictions for the 2022 TAM?**

A. Yes. In Order No. 20-024, the Oregon Commission adopted the 2020 Multi-state Protocol. That agreement contains provisions as to how the costs for QFs are treated for multi-state jurisdictional allocation purposes.[8] For existing QFs, those operating as of December 31, 2019, those purchased power costs will continue to be system assigned until December 31, 2029, when they will become situs assigned. For QFs commencing operation beginning January 1, 2020, those costs are situs allocated.

**Q. Does application of the 2020 Protocol result in a change to QF costs in the 2022 TAM?**

A. It appears so from my review of the Company workpapers for Oregon. Based on PacifiCorp's response to Staff Data Request 23,[9], **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]**

[8] 2020 Protocol, Section 4.4 (UM 1050 – PacifiCorp's Initial Filing at Exhibit PAC/101). .
[9] Staff/503, Zarate/10 (PacifiCorp's confidential response to Staff DR 23)

However, in the Company workpapers, it appears that there are **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[10]**. [BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]**[11].Staff has issued a data request to the Company to confirm this as well as Staff's understanding of the workpapers.

**Q. Do you have any additional concerns with QF costs as forecast in this case?**

A. Yes, I am concerned about the historical relationship of actual QF MWh produced compared PacifiCorp projections.

**Q. What data did PacifiCorp provide with regards to the historical relationship between QF MWh forecasted to QF MWh actual?**

A. In the Attachment to OPUC 114, the tab labeled, "Comparison" PacifiCorp provided summary statistics of QF projected to actual history[12] the confidential table summarizing those results is presented below:

[12] Staff/503, Zarate/10 (Pacificorp's confidential response to Staff DR 23)

**[BEGIN CONFIDENTIAL]**

***Table 1***

| | |
|---|---|
| | [redacted] |
| | |
| [redacted] | [redacted] |
| [redacted] | [redacted] |
| [redacted] | [redacted] |
| [redacted] | [redacted] |
| [redacted] | [redacted] |
| [redacted] | [redacted] |
| [redacted] | [redacted] |

**[END CONFIDENTIAL]**

**Q. What do you conclude from the data?**

A. I conclude that PacifiCorp has a history of overestimating the MWhs produced from PURPA QF projects. The average amount of overestimation is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** The amount of overestimation for 2020 is somewhat less at **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

**Q. Given that PacifiCorp has historically overestimated the amount of MWh produced from PURPA QF projects, do you have an adjustment to recommend?**

A. Yes, I have an adjustment. I begin this discussion with the components needed to build my adjustment. First, we start with PacifiCorp's forecast of

QF purchased power cost which is $337,028,916.[13] Next, we need the SG allocation factor for Oregon which is 26.482%, which is the applicable factor to allocate system costs to Oregon.[14]

The amount of PURPA QF purchase power expense allocated to Oregon is 0.26482 multiplied by $337,028,916. The result of the multiplication is $89,251,998. If you multiply the 2020 MWh overestimation amount, which is lower than the multi-year average, you get a value of $3.2 million.

Next, we take into account that a lower MWh production by QFs will require replacement power to serve load. Purchasing this replacement power will affect net power cost; the incremental increase can be estimated by comparing the QF per-MWh power purchase cost compared to market. In this case, market is the 2022 Mid-C value PacifiCorp projects as compared to the 2020 average QF purchased power cost. The Mid-C 2022 flat load projected price PacifiCorp provides is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].** The 2020 average QF power purchase cost is **[BEGIN CONFIDENTIAL]** [redacted][16] **[END CONFIDENTIAL]** The difference in these two values is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** I then multiply **[BEGIN CONFIDENTIAL** [redacted]**.[END**

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[13] PAC/102, Webb/ 3.
[14] PAC/103, Webb/ 1.
[16] Staff/503, Zarate/13 (PacifiCorp's confidential response to Staff DR 23).

**CONFIDENTIAL]** This calculation yields the percentage negative margin of the average QF power purchase, thus accounting for the cost of replacement power, which I multiply by my Oregon adjustment of $3.2 million. That yields a final adjustment of $1.53 million.

**Q. Because PacifiCorp overstates PURPA QF generation, is it consistent with PacifiCorp's workpapers that an adjustment correcting for the pattern of overestimating would yield a credit to customers?**

**A.** Yes. As mentioned previously with regards to PacifiCorp's workpapers my review has that nearly all of the QFs have a mark-to-Market adjustment of a negative value, meaning that the QF power exceeds near-term market prices. So, an adjustment to the customer's favor is consistent with that finding.

**Q. What Adjustment do you recommend?**

**A.** I recommend an adjustment of $ 1.53 million.

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

A. Yes.

CASE: UE 390
WITNESS: KATHY ZARATE

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

## STAFF EXHIBIT 501

## Witness Qualifications Statement

**June 9, 2021**

**WITNESS QUALIFICATION STATEMENT**

| | |
|---|---|
| NAME: | Kathy Zarate |
| EMPLOYER: | Public Utility Commission of Oregon |
| TITLE: | Utility Economist<br>Energy Rates, Finance and Audit Division |
| ADDRESS: | 201 High Street SE., Suite 100<br>Salem, OR. 97301 |
| EDUCATION: | Bachelor of Arts, Economics<br>Oregon State University, Corvallis, Oregon<br><br>Bachelor Degree in Law<br>Republic University, Santiago, Chile |
| EXPERIENCE: | I have been employed by the Public Utility Commission of Oregon (OPUC) since April 2016, with my current position being a Utility Analyst, in the Energy - Rates, Finance and Audit Division. My responsibilities include research, analysis, and recommendations on a range of regulatory issues such as review of affiliated interest filings, property sales applications and rate proposals.<br><br>I have approximately 10 years of professional experience in contracting and audit review work, including: |

I spent six years as a contract specialist for 3 Com, Santiago, Chile, with responsibilities including coordinating and preparing contracts with resellers, reviewing company books and records, coordinating logistics in business, and working as or with anExpert Witness, Case Manager, Principal Analyst, Econometrician, Economist, Utility Analyst, and Policy Analyst.

I have testified in various formal state hearings and performed numerous analyses including economic, financial, statistical, mathematical, marketing, and policy analyses in public utility industry.

I have served as a Principal Analyst at the OPUC for the determination of Energy Property Sales (Oregon Revised Statute 757.140) for the past 3 years. In this position, I investigated, analyzed, and calculated energy cost and impact.

<u>I also support work related to power costs,</u> plant, and associated impact on customer rates. I have reviewed, calculated, and analyzed QFs, wheeling, forced outage rates and Scheduled maintenance outages, PURPA, Solar forecast, wind forecast (UE 366).

I has worked on power cost issues in the below representative cases:

1. UE 366 Idaho Power.
2. UE 375 PacifiCorp
3. UE 377 Portland General Electric PGE

I generally conduct case investigation and analysis on Utility's filings, make rate adjustments, lead settlement negotiation, prepare testimony, and appear on behalf of the Commission. The energy companies I work with are:

- PacifiCorp
- PGE
- Northwest Natural Gas
- Idaho Power
- Avista Corp
- Cascade Gas

<u>General Rate Cases</u>: I have been a part of <u>almost every energy rate case</u> since I joined the Oregon PUC in 2016. Historically, my review has included, property sales, material and supply, donations, marketing cost. Currently, my review includes property sales and low-income issues. My work is generally represented in the last four General Rate cases, as examples:

- UG 388 NW Natural
- UE 374 Pacificorp
- UG 389 Avista
- UG 390 Cascade

<u>Rulemaking</u>: I have formulated energy regulation rules for utility performance incentives and cost-of-service regulation.

<u>Low-Income:</u> Results of my statistical sampling design and sampling procedures are incorporated into my revenue requirement testimony in Commission Docket No. UM 2058.

<u>Auditing, Interest Rate, Affiliated Interest</u>: I audited cost of capital and financial components (IU 437)

CASE: UE 390
WITNESS: KATHY ZARATE

# PUBLIC UTILITY COMMISSION
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# STAFF EXHIBIT 502

## Exhibits in Support
## Of Opening Testimony

**June 9, 2021**

UE 390 / PacifiCorp
May 7, 2021
OPUC Data Request 34

**OPUC Data Request 34**

**Other Revenues -** Please refer to PAC/100, Webb/3, and line 21. Please provide documentation supporting the Company's update to Other Revenues, including details of PacifiCorp's "Schedule 205 rates were adjusted to zero as the previous adjustments were incorporated into base rates".

**Response to OPUC Data Request 34**

There is no adjustment related to Other Revenues included in the Company's 2022 transition adjustment mechanism (TAM) filing.

Please refer to PacifiCorp's approved Oregon Schedule 205 which shows rates adjusted to zero. Schedule 205 is publicly available and can be accessed by utilizing the following website link:

https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/rates-regulation/oregon/tariffs/rates/205_TAM_Adjustment_for_Other_Revenues.pdf

UE 390 / PacifiCorp
May 7, 2021
OPUC Data Request 36

**OPUC Data Request 36**

**Standard Inputs –** Please describe the factors considered, such as cost of replacement power, in adopting the timing of the 2022 maintenance for the resources.

**Response to OPUC Data Request 36**

When making decisions for the scheduling of planned maintenance for 2022, 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 2022, 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 also schedules the planned 2022 outages to avoid forecasted peak system needs, i.e. peak summer obligations and peak winter obligations.

CASE: UE 390
WITNESS: KATHY ZARATE

# PUBLIC UTILITY COMMISSION
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# STAFF EXHIBIT 503

## Exhibits in Support
## Of Opening Testimony

**June 9, 2021**

UE 390 / PacifiCorp
May 4, 2021
OPUC Data Request 23

**OPUC Data Request 23**

**Qualifying Facilities -** For TAM test years 2015, 2016, 2017, 2018, 2019, 2020 and 2021, please provide the projected total cost of QF supplied power for new QFs coming online in the projected test year, the actual purchased power cost of QF supplied power for that test year, and the percentage of actual to projected purchased power costs.

**Response to OPUC Data Request 23**

The Company objects to this request as outside the scope of this proceeding. The relevant forecast period for the 2022 transition adjustment mechanism (TAM) is calendar year 2022, and where applicable / appropriate, is based on up to four-years of historical actual information, July 1, 2017 through June 30, 2020. Notwithstanding the foregoing objection, the Company responds as follows:

The Company assumes that the reference to “TAM test years” is as follows:

Docket UE 287 - 2015 TAM (forecast calendar year 2015)
Docket UE 296 - 2016 TAM (forecast calendar year 2016)
Docket UE 307 - 2017 TAM (forecast calendar year 2017)
Docket UE 323 - 2018 TAM (forecast calendar year 2018)
Docket UE 339 - 2019 TAM (forecast calendar year 2019)
Docket UE 356 - 2020 TAM (forecast calendar year 2020)
Docket UE 375 - 2021 TAM (forecast calendar year 2021)

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

Please refer to Confidential Attachment OPUC 23.

Note 1: this response includes information regarding large qualifying facilities (QF) only (greater than 10 megawatts (MW)) because small QFs are not itemized in the net power costs (NPC) forecast.

Note 2: the cost information provided covers TAM forecast years and actuals for 2015 through 2020. Cost information for calendar year 2021 actuals is not yet available 1.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

UE 390 / PacifiCorp
May 21, 2021
OPUC Data Request 114

**OPUC Data Request 114**

**CONFIDENTIAL REQUEST – ORTAM22 Testimony Support work paper**
Regarding the Confidential workbook "ORTAM22 Testimony Support":

**[CONFIDENTIAL BEGINS]**

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

**[CONFIDENTIAL ENDS]**

**Response to OPUC Data Request 114**

(a) Confirmed.

(b) Yes, category "coal generation" includes generation from Cholla. The historical window in question was prior to the retirement of Cholla Unit 4, therefore, without the inclusion of Cholla Unit 4 generation, requirements and resources would not balance.

(c) "Total Requirements" as referred to in the direct testimony of Company witness, David G. Webb, page 31, line 19 represents system load plus sales volumes.

(d) Note – the Company's response is based on the information provided in Public Utility Commission of Oregon (OPUC) staff provided attachment, file "PAC UE 390 OPUC DR 114 CONF Attach A." The consistent trend of transition adjustment mechanism (TAM) forecast coal generation values being larger than actuals is attributable to several factors, including normal forecast error, and changes in system conditions and/or prices between the date of the forecast and the individual balancing hours. However, one clear potential model-driven factor is the over-forecasting of sales in the TAM, which the Company has attempted to resolve in this year's filing through an adjustment to the market capacity input. As described in subpart (c) above, sales are additive to requirements. That also explains a portion of the over-forecasting of requirements as well (visible in cells N5 through N13). Increased requirements have the consequence of increasing dispatchable generation, which offers one potential explanation for why natural gas generation volumes have also been consistently over-forecasted in the TAM.

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

(f) Please refer to Confidential Attachment OPUC 114, tab "Tab B."

(g) Please refer to Confidential Attachment OPUC 114, tab "Tab C."

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

CASE: UE 390
WITNESS: JOHN L. FOX

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 600

# Opening Testimony

**June 9, 2021**

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

A. My name is John L. Fox. I am a Senior Financial Analyst employed in the Energy 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. The purpose of my testimony is to present Staff's analysis of Coal Fuel Burn Expense included in the initial filing,[1] alternative modeling provided by the Company, and related issues.

**Q. Did you prepare any additional exhibits for this docket?**

A. Yes. In addition to Exhibit Staff/601, I prepared Exhibit Staff/602 (PacifiCorp's response to Data Requests).

**Q. How is your testimony organized?**

A. My testimony is organized as follows:



[1] PAC/102, Webb/5.

## ISSUE 1, OVERVIEW, AREAS OF CONCERN, AND STAFF RECOMMENDATIONS

**Q. What coal-related issues does PacifiCorp's testimony address?**

A. PacifiCorp's testimony addresses the following coal-issues:

- 2022 coal fuel expense:
  - Includes updated coal pricing and background on third-party coal contracts and affiliate-owned mines
  - Drivers behind reduction in coal-fuel expense
- Modeling for coal costs:
  - 2022 initial filing run ("must run" setting turned off);[2]
  - Counterfactual Run ("must run" setting turned on);[3]
  - Informational Run ("must run" setting turned off, no minimum take adjustments, average price of coal utilized);[4] and
  - Economic Coal Cycling Study (based on the 2021 TAM, "must run" setting removed").[5]
- Five new coal supply agreements: two related to the Dave Johnson Plant, two related to the Hunter plant, and one related to the Craig plant.
- Coal Supply Agreement for the Huntington Plant.

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[2] PAC/100, Webb/14.
[3] PAC/100, Webb/17.
[4] PAC/100, Webb/23.
[5] PAC/100, Webb/14; PAC/107.

**Q. Please explain which Staff witnesses are addressing each coal-related issue.**

A. My testimony addresses 2022 coal fuel expense, including the following model runs: (1) 2022 initial filing, (2) counterfactual run, and (3) informational run. The testimony of Staff witness Ms. Rose Anderson (Staff/700) addresses the five new coal supply agreements, Huntington coal supply agreement and the Economic Coal Cycling Study.

**Q. Regarding overall coal fuel expense in the 2022 TAM what does Staff recommend?**

A. Staff recommends the Commission accept the Company's estimate for coal fuel burn expense of $543.4 million, with one adjustment related to the Huntington plant. This adjustment will be discussed in detail by Staff witness Ms. Rose Anderson in Staff/700.

The various model runs provided by the Company include coal fuel burn expense ranging between **[BEGIN CONFIDENTIAL]** [redacted][6] **[END CONFIDENTIAL]** and overall net power costs ranging from **[BEGIN CONFIDENTIAL]** [redacted][7] **[END CONFIDENTIAL]** million. Staff finds the Company's filed case to be a reasonable estimate of 2022 coal fuel burn expense, with the exception of coal costs for Huntington.

[6] Staff Table 1 below.
[7] *Id.*

**Q. Has Staff identified any areas of concern related to coal fuel expense for Commission consideration?**

A. Yes, Staff has identified two areas of concern. First, Staff notes there is an unusual increase in the burn rate for the Naughton plant. Second, Staff questions the commitment to increase contracted supply at the Dave Johnston plant when the Company cites a highly competitive local market with numerous supply options.

**ISSUE 2, REVIEW OF COAL FUEL EXPENSE IN THE COMPANY'S FILING**

**Q. Please summarize the decrease in coal fuel expense from last year's TAM.**

A. Coal fuel expense in the initial filing is $543.4 million[8] which is a decrease of ($114.2) million[9] compared to coal fuel expense of $657.6 million[10] in the final 2021 TAM.

**Q. Does the $543.4 million figure represent a particular set of assumptions regarding economic cycling of coal units?**

A. Yes, as discussed in the Company's testimony, the initial filing run reflects removal of the must run setting,[11] certain modeling adjustments necessary "so that GRID can make rational commitment decisions,"[12] and accommodates minimum take requirements of various coal supply agreements.[13]

**Q. Has the Company provided alternative model runs that reflect other, differing assumptions, for calculating 2022 NPC?**

A. Yes, two.

First, the Company provides what it refers to as a "counterfactual study" where the must run setting is included (Counterfactual Run).[14]

Second, the Company provides, in compliance with last year's stipulation, a "model run that removes any operational constraints related to the minimum

[8] PAC/102, Webb/5.
[9] PAC/200, Ralston/13.
[10] PAC/101, Webb/1.
[11] PAC/100, Webb/12.
[12] PAC/100, Webb/15.
[13] PAC/100, Webb/30.
[14] PAC/100, Webb/17 and workpaper "SL02 ORTAM22_xCoal Cycling CONF.xlsm"

take provisions in the coal supply agreements and uses an average coal price for purposes of dispatching coal plants."[15] This is referred to as the "Informational Run."

**Q. Has Staff compared dollar results of the 2022 initial filing run, Counterfactual Run, and Informational Run with the final 2021 model run?**

A. Yes, Staff has prepared the following table summarizing the results.

**[BEGIN CONFIDENTIAL]**

| Staff Table 1 | 2021 Final | 2022 Filed | "Counterfactual Study" | "Informational Run" |
|---|---|---|---|---|
| Total Special Sales For Resale | $ (349,266,420) | $ (252,454,345) | [redacted] | [redacted] |
| Total Purchased Power & Net Interchange | 673,666,674 | 663,806,761 | [redacted] | [redacted] |
| Total Wheeling & U. of F. Expense | 139,128,726 | 147,601,542 | [redacted] | [redacted] |
| Total Coal Fuel Burn Expense | 657,614,065 | 543,415,251 | [redacted] | [redacted] |
| Total Gas Fuel Burn Expense | 283,529,634 | 339,118,737 | [redacted] | [redacted] |
| Total Other Generation | 4,508,022 | 3,966,594 | [redacted] | [redacted] |
| Settlement Adjustment | (8,802,107) | | | |
| | $ 1,400,378,594 | $ 1,445,454,540 | [redacted] | [redacted] |

Decrease Coal Fuel Expense $ (114,198,814)

**[END CONFIDENTIAL]**

The 2022 initial filing run ("must run" off) decrease in coal fuel expense of ($114.2) has been previously discussed above. As the Company has stated in testimony, the Counterfactual Run ("must run" on) increases coal fuel expense by "approximately three percent"[16] (from $543.4 to **[BEGIN CONFIDENTIAL]** [redacted][17] **[END CONFIDENTIAL]** million) while overall power costs "fell very

[15] PAC/100, Webb/23 and workpaper "zz_ORTAM22_Avg Fuel Cost Final CONF.xlsm."
[16] PAC/100, Webb/17.
[17] Staff Table 1 above.

slightly"[18] (from $1,445.5 to **[BEGIN CONFIDENTIAL]** [redacted][19] **[END CONFIDENTIAL]** million). The Informational Run ("must run" off, operational constraints removed) results in a *decrease* in coal fuel expense of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** while *increasing* net power costs by **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

**Q. The results of the Informational Study appear to be counter intuitive. What is the Company's explanation?**

A. The Informational Run does not iterate for minimum take but does adjust for take or pay by increasing the average cost to compensate.[20] Even though the costs are included, the lower coal generation in the model must be replaced by other resources.[21]

**Q. What is average coal cost and how does it differ from dispatch cost?**

A. The Company defines the difference as follows:

> The "dispatch tier" costs are the incremental costs to operate PacifiCorp's coal plants. The incremental cost is the change in cost to generate additional generation from each power plant. The incremental costs include the cost to purchase additional fuel, the incremental heat rate (efficiency) to operate the plant, and the variable operations and maintenance expense. GRID dispatches individual resources on a marginal or incremental cost basis, to optimize the dispatch of the Company's existing system in the most economic manner while accounting for system constraints.

[18] PAC/100, Webb/17.
[19] Staff Table 1 above.
[20] Staff/602, Fox/14 (PacifiCorp's response to Sierra Club Data Request 2.17).
[21] As explained at the technical workshop which occurred on May 14, 2021.

> The "costing tier" is the average annual unit price for fuel expense. The average cost of coal includes all of the cost of coal purchased under existing coal supply agreements or from company mining operations. GRID uses the costing tier price multiplied by the coal volumes to arrive at the total coal fuel expense.[22]

**Q. Does Staff feel that the Informational Run is sufficient to inform the parties and the Commission?**

A. No. Issue 1 in the Commission's May 21, 2021 Issues List asks the parties to address the Informational Run:

> [A]nd how much it changed the coal plants' production levels, and net power costs overall. If a specific workpaper is useful for understanding the informational run, please provide the folder name and file name. If the informational run produced coal unit capacity factors that are closer to Integrated Resource Plan (IRP) modeling, please address which modeling approach is more appropriate for the power cost proceeding.[23]

In Staff's view, the informational run should exclude all take or pay, and/or liquidated damage provisions so that the impact of minimum take provisions can be clearly isolated and observed. Although minimum take costs are valid costs when incurred pursuant to a prudent contract, as discussed in in Staff witness Ms. Rose Anderson's testimony (Staff/700, Issue 2), removing both operational constraints and costs related to minimum take provisions avoids obscuring the effects of economic cycling for purposes of the Informational Run. Staff suggests adding "and costs" to the Company's definition informational run as follows:

[22] Staff/602, Fox/10 (PacifiCorp's response to Sierra Club Data Request 1.2).
[23] UE 390 – Issues List (May 21, 2021).

"model run that removes any operational constraints ***and costs*** related to the minimum take provisions in the coal supply agreements and uses an average coal price for purposes of dispatching coal plants"[24]

**Q. Regarding the difference in 2022 coal costs with and without the must run setting (2022 Initial Run and Counterfactual Run), does the Company assert that the differences are representative of what might occur in future years?**

A. No, the Company states the "the economic benefits of cycling the coal units are de minimis for the 2022 test period."[25] The Company did not undertake a longer term analysis in this case.

**Q. Does Staff agree with the Company's analysis of why coal costs are varying from the final 2021 TAM?**

A. Not entirely.

The Company explains that coal expense is "lower than the 2021 TAM due to lower coal generation volume at the Company's coal plants"[26] and also that the "decrease is a result of a $114.2 million volume reduction in coal-fired generation, partially offset by approximately $0.2 million in higher coal prices."[27]

Regarding the price variance, Staff agrees with the Company's calculation with a small exception for the Craig plant, discussed below. Staff also notes that,

[24] PAC/100, Webb/23 and workpaper "zz_ORTAM22_Avg Fuel Cost Final CONF.xlsm."
[25] PAC/100, Webb/17.
[26] PAC/100, Webb/20.
[27] PAC/200, Ralston/13.

although the overall variance for all plants is near zero, there are large price variances associated with individual plants that will be further discussed below. Staff finds that a portion of the remaining variance is driven by changes in the Burn Rate (MMBtu per MWh)[28] resulting in overall variances by plant as shown in the following table:[29]

**[BEGIN CONFIDENTIAL]**

| Staff Table 2 | Variance Analysis | | | |
|---|---|---|---|---|
| | Fuel Price | Burn Rate | Volume | Total |
| Jim Bridger | [redacted] | [redacted] | [redacted] | [redacted] |
| Hunter | [redacted] | [redacted] | [redacted] | [redacted] |
| Huntington | [redacted] | [redacted] | [redacted] | [redacted] |
| Dave Johnston | [redacted] | [redacted] | [redacted] | [redacted] |
| Naughton | [redacted] | [redacted] | [redacted] | [redacted] |
| Wyodak | [redacted] | [redacted] | [redacted] | [redacted] |
| Craig | [redacted] | [redacted] | [redacted] | [redacted] |
| Colstrip | [redacted] | [redacted] | [redacted] | [redacted] |
| Hayden | [redacted] | [redacted] | [redacted] | [redacted] |
| | [redacted] | [redacted] | [redacted] | [redacted] |

**[END CONFIDENTIAL]**

**Q. What is the magnitude of change in burn rate for each plant?**

A. The magnitude of change is less than plus or minus **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for all plants except Naughton and Wyodak, as illustrated in the following table:[30]

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[28] Staff calculates this variance as the 2022 Fuel Use x the change in Burn Rate (MMBtu/MWh).
[29] Calculated by Staff using data from the following files: ORTAM22 NPC CONF.xlsm and _Final ORTAM21 Fin Nov NPC CONF -TB and Pryor Constant.xlsm.
[30] *Id.*

**[BEGIN CONFIDENTIAL]**

| Staff Table 3 | Burn Rates (MMBtu/Mwh) | | |
|---|---|---|---|
| | 2021 | 2022 | % Chg. |
| Colstrip | [redacted] | [redacted] | [redacted] |
| Craig | [redacted] | [redacted] | [redacted] |
| Dave Johnston | [redacted] | [redacted] | [redacted] |
| Hayden | [redacted] | [redacted] | [redacted] |
| Hunter | [redacted] | [redacted] | [redacted] |
| Huntington | [redacted] | [redacted] | [redacted] |
| Jim Bridger | [redacted] | [redacted] | [redacted] |
| Naughton | [redacted] | [redacted] | [redacted] |
| Wyodak | [redacted] | [redacted] | [redacted] |

**[END CONFIDENTIAL]**

**Q. What is the Company's explanation for the burn rate increases at Naughton and Wyodak?**

A. In general, the Company explains:

> All of the changes to the burn rates (heat rates) are forecast values for both 2021 and 2022. These are based on historical performance, and adjusted for future years based on degradation, maintenance schedules, and generation levels. The average annual forecast burn rates are calculated using curves developed to cover the entire load range. Heat rates are typically best at loads above 85 percent and increase for lower loads. The heat rate, or burn rate, for 50 percent load is about 5 percent to 10 percent higher than the unit's best efficiency point. At 10 percent of maximum load, heat rate can increase by 50 percent, however since the load is reduced it will affect the average annual heat rate by a lesser amount.[31]

Regarding Naughton and Wyodak specifically:

**[BEGIN CONFIDENTIAL]**

[redacted]

[31] Staff/602, Fox/5 (PacifiCorp response to Staff DR 113).

[redacted][32]

[redacted][33]

**[END CONFIDENTIAL]**

> Wyodak utilizes an air-cooled condenser. It is the only coal-fired unit in the fleet with this type of condenser. The air-cooled condenser is less efficient at cooling the steam passing through the turbine than a cooling tower or a once through water cooled condenser. Therefore, the turbine was designed to operate at a higher backpressure. This higher backpressure decreases the total available energy that can be extracted from the steam and decreases the efficiency of the unit by design.[34]

**Q. How has the fuel cost per MWh changed compared to the 2021 final TAM?**

A. The Company states that "average coal prices are $0.42/MWh lower than prices in the 2021 TAM"[35] which is a decrease from **[BEGIN CONFIDENTIAL]** [redacted][36] **[END CONFIDENTIAL]** on average for all plants. However, the cost per MWh varies within a range of plus or minus **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for individual plants as shown in the following table:[37]

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[32] *Id.*
[33] *Id.*
[34] *Id.*
[35] PAC/100, Webb/20.
[36] Staff Table 4 below.
[37] Calculated by Staff using data from the following files: ORTAM22 NPC CONF.xlsm and _Final ORTAM21 Fin Nov NPC CONF -TB and Pryor Constant.xlsm.

**[BEGIN CONFIDENTIAL]**

| | Cost per Mwh | | |
|---|---|---|---|
| **Staff Table 4** | **2021** | **2022** | **% Chg.** |
| Jim Bridger | [redacted] | [redacted] | [redacted] |
| Hunter | [redacted] | [redacted] | [redacted] |
| Huntington | [redacted] | [redacted] | [redacted] |
| Dave Johnston | [redacted] | [redacted] | [redacted] |
| Naughton | [redacted] | [redacted] | [redacted] |
| Wyodak | [redacted] | [redacted] | [redacted] |
| Craig | [redacted] | [redacted] | [redacted] |
| Colstrip | [redacted] | [redacted] | [redacted] |
| Hayden | [redacted] | [redacted] | [redacted] |
| **System Average** | [redacted] | [redacted] | [redacted] |

**[END CONFIDENTIAL]**

**Q. Regarding the plants with new coal supply agreements, is the cost per MWh increasing or decreasing?**

A. The Company states that there are "five new coal supply agreements: two related to the Dave Johnston plant, two related to the Hunter plant, and one related to the Craig plant."[38] The table above shows a cost per MWh increase of **[BEGIN CONFIDENTIAL]** [redacted][39] **[END CONFIDENTIAL]** respectively. Staff also notes that the 2022 cost per MWh for all three plants is less than the system average of **[BEGIN CONFIDENTIAL]** [redacted][40] **[END CONFIDENTIAL]** per MWh and also less than the overall average of **[BEGIN CONFIDENTIAL]** [redacted][41] **[END CONFIDENTIAL]** per MWh for all resources.

[38] PAC/200, Ralston/2.
[39] Staff Table 4 above.
[40] Staff Table 4 above.
[41] PAC/102, Webb/6.

**Q. In support of the discussion below, what is the average cost per MWh for all resources in the filed case?**

A. **[BEGIN CONFIDENTIAL]** [redacted]."[42] **[END CONFIDENTIAL]**

**Q. In support of the discussion below, please summarize the 2021 and 2022 coal fuel expense by plant.**

A. The following tables show both cost and energy for each year.[43]

[42] *Id.*
[43] Calculated by Staff using data from the following files: ORTAM22 NPC CONF.xlsm and _Final ORTAM21 Fin Nov NPC CONF -TB and Pryor Constant.xlsm.

**[BEGIN CONFIDENTIAL]**

| Staff Table 5 | 2021 Final TAM Total $ | Mwh | $ per Mwh |
|---|---|---|---|
| Jim Bridger | 227,626,287 | [redacted] | [redacted] |
| Huntington | 113,605,614 | [redacted] | [redacted] |
| Hunter | 104,626,717 | [redacted] | [redacted] |
| Naughton | 80,743,377 | [redacted] | [redacted] |
| Dave Johnston | 54,006,195 | [redacted] | [redacted] |
| Wyodak | 27,581,753 | [redacted] | [redacted] |
| Craig | 17,940,209 | [redacted] | [redacted] |
| Colstrip | 16,752,375 | [redacted] | [redacted] |
| Hayden | 14,731,538 | [redacted] | [redacted] |
| | 657,614,065 | [redacted] | [redacted] |

| Staff Table 6 | 2022 TAM Total $ | Mwh | $ per Mwh |
|---|---|---|---|
| Jim Bridger | 185,570,462 | [redacted] | [redacted] |
| Hunter | 103,544,708 | [redacted] | [redacted] |
| Huntington | 99,945,126 | [redacted] | [redacted] |
| Dave Johnston | 61,444,601 | [redacted] | [redacted] |
| Naughton | 24,416,678 | [redacted] | [redacted] |
| Wyodak | 23,501,147 | [redacted] | [redacted] |
| Craig | 19,084,507 | [redacted] | [redacted] |
| Colstrip | 14,529,149 | [redacted] | [redacted] |
| Hayden | 11,378,872 | [redacted] | [redacted] |
| Other | | | |
| | 543,415,251 | [redacted] | [redacted] |

**[END CONFIDENTIAL]**

## JIM BRIDGER

**Q. Please summarize the Company's filing regarding the Jim Bridger plant.**

A. Fuel costs in the 2022 TAM decreased from $227.6 million to $185.6 million[44] and energy output decreased from **[BEGIN CONFIDENTIAL]** [redacted]

[44] Staff Tables 5 and 6, above.

[redacted][45] **[END CONFIDENTIAL]** MWh compared to the final 2021 TAM. The average cost also decreased from **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per MWh.[46] The Company reports that the cost of the Bridger Base Mine Plan decreased by **[BEGIN CONFIDENTIAL]** [redacted][47] **[END CONFIDENTIAL]** million however the volume decrease was a slightly higher **[BEGIN CONFIDENTIAL]** [redacted][48] **[END CONFIDENTIAL]** tons resulting in an increased unit cost from **[BEGIN CONFIDENTIAL]** [redacted][49] **[END CONFIDENTIAL]** per ton. The cost of supplemental deliveries from the Bridger Mine decreased from **[BEGIN CONFIDENTIAL]** [redacted][50] **[END CONFIDENTIAL]** per ton, comprising most of an overall favorable cost variance of ($10.9) million dollars. Deliveries from the Black Butte mine are expected to increase from **[BEGIN CONFIDENTIAL]** [redacted][51] **[END CONFIDENTIAL]** tons at an increased cost of **[BEGIN CONFIDENTIAL]** [redacted][52] **[END CONFIDENTIAL]** per ton or $500,000.

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[45] *Id.*
[46] *Id.*
[47] PAC/200, Ralston/15.
[48] *Id.*
[49] *Id.*
[50] *Id.*
[51] *Id.*
[52] *Id.*

**Q. In Staff's view, are the changes in mine operation costs reasonable compared to the changes in projected volume deliveries?**

A. Yes, coal deliveries **[BEGIN CONFIDENTIAL]** [redacted][53] [redacted][54] [redacted][55] **[END CONFIDENTIAL]**

**Q. Why did the overall base cost per ton increase, then?**

A. Mostly due to the increased reclamation and inventory costs.[56] However, the overall cost of Bridger coal delivered (base plan plus supplemental) decreased from **[BEGIN CONFIDENTIAL]** [redacted][57] **[END CONFIDENTIAL]** per ton. It would appear that some of the line-item savings are being passed through as savings in the supplemental coal costs.

**Q. The Company states that the changes in mine operating costs are primarily due to reduced volume, closure of the underground mine, and increased deliveries from the surface mine.[58] Does Staff agree?**

A. Yes.

[53] Reduction calculated by Staff based on Ralston workpapers "Cost Comparison.xlsx."
[54] *Id.*
[55] *Id.*
[56] *Id.*
[57] PAC/200, Ralston/15.
[58] PAC/200, Ralston/16.

**Q. Please discuss the third party coal supply for Bridger.**

A. The Company expects to renew the contract with Black Butte at a price of **[BEGIN CONFIDENTIAL]** [redacted][59] **[END CONFIDENTIAL]** per ton which is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** increase over the 2021 price of **[BEGIN CONFIDENTIAL]** [redacted][60] **[END CONFIDENTIAL]** per ton. However, Staff notes that Bridger remains one of the highest cost resources at **[BEGIN CONFIDENTIAL]** [redacted][61] **[END CONFIDENTIAL]** per MWh compared with the average of **[BEGIN CONFIDENTIAL]** [redacted][62] **[END CONFIDENTIAL]** per MWh. The Company has not provided evidence that renewal of the contract is prudent.

**Q. Is Staff recommending a power cost adjustment for the Bridger plant?**

A. No. Not at this time.

## <u>HUNTER</u>

**Q. Please summarize the Company's filing regarding the Hunter plant.**

A. The Company entered into two new coal supply agreements for the Hunter plant – one with Bronco Utah Operations LLC (Bronco) and one with Wolverine Fuels LLC (Wolverine) that cover fuel costs in the 2022 test year.[63] Fuel costs in the 2022 TAM decreased from $104.6 million to $103.5 million[64] and energy output decreased from **[BEGIN CONFIDENTIAL]** [redacted] [redacted][65]

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[59] PAC/200, Ralston/18.
[60] *Id.*
[61] Staff Table 6, above.
[62] *Id.*
[63] PAC/200, Ralston/7 and PAC/200, Ralston/10.
[64] Staff Tables 5 and 6, above.
[65] *Id.*

**[END CONFIDENTIAL]** MWh compared to the final 2021 TAM. However, the average cost increased from **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per MWh.[66] The Company reports a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** cost increase due to two new supply arrangements including "**[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** is related to the expiration of the refined coal credit PacifiCorp was receiving."[67] The Company also asserts that the decision to enter into two new coal supply agreements was prudent.[68]

**Q. Has the Company provided additional information regarding the expiration of the refined coal credits?**

A. Yes, the Company explains that qualification for the credit is based on tons of coal treated using a specific process which applies chemicals to coal to reduce emissions.[69] This process occurs at the Hunter and Dave Johnston plants only. Staff understands PacifiCorp to anticipates the credit end date is December 2021 and that the Company does not expect Congress to renew.[70]

Further Staff's review of IRS instructions for claiming the credit indicate that the credit was available for "A refined coal production facility originally placed in service after October 22, 2004, and before January 1, 2012" and that the credit was available for 10 "years from placed in-service date."[71] Accordingly, Staff

[66] *Id.*
[67] PAC/200, Ralston/20.
[68] PAC/200, Ralston/2; PAC/200, Ralston/7.
[69] As explained at the technical workshop which occurred on May 14, 2021.
[70] *Id.*
[71] Internal Revenue Service, Instructions for Form 8835 (2020).

concludes that the credit phase out is simply due to the passage of time and the associated increases in 2022 power costs are unavoidable.

**Q. Please provide an overview of the two new coal supply agreements.**

A. The two new agreements were both effective at the beginning of 2021 and have terms of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** years for the Wolverine and Bronco agreements, respectively. The combined minimum take requirement for both is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** tons per year.[72] The Company reports that this a continuation of the same minimum take level which was in place prior to 2021.[73] The Company states that updated generation forecasts occurred at the time of the agreements supporting the minimum level.[74] Information from these forecasts have been provided to Staff.[75]

**Q. Does Staff believe the coal prices in the two new agreements are reasonable for 2022?**

A. The prudence of both new Hunter contracts is addressed in Staff witness Ms. Rose Anderson's testimony (Staff/700). As Ms. Anderson's testimony indicates, for 2022, there is no proposed adjustment related to Hunter coal costs based on the new contracts.[76]

[72] PAC/200, Ralston/7-8.
[73] PAC/200, Ralston/8.
[74] PAC/200, Ralston/9.
[75] Staff/602, Fox/2 (PacifiCorp's response to Staff DR 71).
[76] Staff/700, Anderson/16.

**Q. Please discuss the burn rate variance for Hunter.**

A. The burn rate for the Hunter plant increased from **[BEGIN CONFIDENTIAL]** [redacted][77] **[END CONFIDENTIAL]** MMBtu/MWh which increases 2022 power costs by **[BEGIN CONFIDENTIAL]** [redacted][78] **[END CONFIDENTIAL]** million. However, this is change of **[BEGIN CONFIDENTIAL]** [redacted][79] **[END CONFIDENTIAL]** which is comparable to other plants in the Company's portfolio.

**Q. Is Staff recommending a power cost dollar adjustment for the Hunter plant?**

A. Not at this time.

**HUNTINGTON**

**Q. Please summarize the Company's filing regarding the Huntington plant.**

A. Fuel costs in the 2022 TAM decreased from $113.6 million to $100.0 million[80] and energy output decreased from **[BEGIN CONFIDENTIAL]** [redacted][81] **[END CONFIDENTIAL]** MWh compared to the final 2021 TAM. However, the average cost increased from **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per MWh.[82] The Company states that coal costs are "higher in 2022 primarily because of contractual increase in the

[77] Staff Table 3 above.
[78] Staff Table 2 above.
[79] Staff Table 3 above.
[80] Staff Tables 5 and 6, above.
[81] *Id.*
[82] *Id.*

contract price, partially offset by an increase in tier 2 coal deliveries and a small decrease in the transportation cost escalator."[83]

**Q. Does Staff agree with the Company's analysis of the factors causing the price increase?**

A. Yes. Staff agrees that the cost driver for the increase in cost per ton is a blend of a **[BEGIN CONFIDENTIAL]** [redacted][84] **[END CONFIDENTIAL]** for tier 1 and the increase is slightly less, **[BEGIN CONFIDENTIAL]** [redacted][85] **[END CONFIDENTIAL]** when tier 2 deliveries are included.

**Q. Please discuss minimum take provisions for Huntington.**

A. The Commission addressed coal costs for Huntington in its 2021 TAM order, stating:

> … since 2015, we have seen decreases in overall market and power supply costs, while we have seen increases in coal fueling costs, including at Huntington. This raises the question of how we should approach fuel costs if portions of the coal delivery required by Huntington's minimum take requirement are not economic on a $/MWh basis relative to the rest of PacifiCorp's generation fleet and PacifiCorp's market forecast.[86]

Minimum take provisions for Huntington, as well as the treatment of minimum take provisions in coal supply agreements, generally, are addressed in the testimony of Staff witness Ms. Rose Anderson (Staff/700).

[83] PAC/200, Ralston/21.
[84] Percentage change calculated by Staff based on Ralston workpaper "Cost Comparison.xlsx."
[85] *Id.*
[86] *In re PacifiCorp*, OPUC Docket No. UE 375, Order No. 20-392 at 10 (Oct. 30, 2020).

**Q. Is Staff recommending a power cost adjustment for the Huntington plant?**

A. There is no adjustment based on the price of coal at Huntington. See the testimony of Staff Witness Ms. Rose Anderson (Staff/700) for Staff's recommendation regarding minimum take levels.

## DAVE JOHNSTON

**Q. Please summarize the Company's filing regarding the Dave Johnston plant.**

A. Fuel costs in the 2022 TAM increased from $54.0 million to $61.4 million[87] and energy output increased from **[BEGIN CONFIDENTIAL]** [redacted][88] **[END CONFIDENTIAL]** MWh compared to the final 2021 TAM. The average cost also increased from **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per MWh.[89] The Company states that delivered coal cost increased by **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** including an increase in coal costs of **[BEGIN CONFIDENTIAL]** [redacted], **[END CONFIDENTIAL]** an increase of rail cost of approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for increases to rail indices and diesel fuel costs, and an increase of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for the expiration of the refined coal credits PacifiCorp was receiving.[90]

[87] Staff Tables 5 and 6, above.
[88] *Id.*
[89] *Id.*
[90] PAC/200, Ralston/19-20. Also, see the discussion of refined coal credits under the Hunter plant section above.

The Company also reports that approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of the plant's coal supply is under contract and the remaining **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** open position is expected to be filled at a reduced price of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per ton compared to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per ton in the 2021 TAM.[91]

**Q. Please discuss the four coal supply contracts for the Dave Johnston Plant.**

A. Staff finds it useful to think of the changes in aggregate as illustrated in the following table:[92]

[91] PAC/200, Ralston/20.
[92] Ralston work papers, Cost Comparison.xlsx, percentage change and average cost per ton calculated by Staff.

**[BEGIN CONFIDENTIAL]**

| Staff Table 7 | 2022 Tons | 2021 Tons | |
|---|---|---|---|
| NARM | [redacted] | [redacted] | |
| Caballo | [redacted] | [redacted] | |
| Caballo | [redacted] | - | |
| Coal Creek | [redacted] | [redacted] | |
| | [redacted] | [redacted] | [redacted] |
| Spot Purchases | [redacted] | [redacted] | |
| | [redacted] | [redacted] | |

| | 2022 Cost (000's) | 2021 Cost (000's) |
|---|---|---|
| NARM | [redacted] | [redacted] |
| Caballo | [redacted] | [redacted] |
| Caballo | [redacted] | [redacted] |
| Coal Creek | [redacted] | [redacted] |
| | [redacted] | [redacted] |
| Average Cost per Ton | [redacted] | [redacted] |

. **[END CONFIDENTIAL]**

This table indicates that the amount of supply under contract increased from **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in the 2022 TAM.[93] The average cost per ton under contract increased from **[BEGIN CONFIDENTIAL]** [redacted][94] **[END CONFIDENTIAL]**

[93] PAC/200, Ralston/20 and Staff Table 7 above.
[94] Staff Table 7 above.

**Q. How did the average cost per ton under contract compare to market prices in 2021?**

A. At this time, favorably. In 2021 the average cost per ton for the open position was **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per ton[95] compared to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per ton[96] under contract. In other words, the Company enjoyed a savings of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per ton by contracting rather than purchasing on the open market.

In 2021 the average cost per ton for the open position was [redacted] per ton compared to [redacted] per ton under contract.[97] The contracted price is now slightly higher than the open market price.[98]

**Q. Has the Company demonstrated that the new supply contract are cost effective?**

A. Not necessarily, increasing the amount of contracted supply while losing the advantage of below market pricing doesn't seem to make financial sense. Staff invites the Company to provide additional evidence that entering into a contract above the spot price is reasonable over the contract term.

**Q. What does the Company say about availability of coal in the region?**

A. The Company states:

> The two separate coal supply agreements are for coal deliveries from two separate mines, Caballo and North Antelope Rochelle (NARM). Both mines are located in the Powder River Basin, the largest coal

[95] PAC/200, Ralston/20
[96] Staff Table 7 above.
[97] PAC/200, Ralston/20 and Staff Table 7 above.
[98] *Id.*

> producing region in the United States. Due to the abundance of coal in the Powder River Basin, along with the number of operating mines in this region, PacifiCorp is able to take advantage of very favorable coal market pricing that exists in the Powder River Basin.[99]

**Q. What is the long term outlook for prices in the Powder River basin?**

A. Staff's understanding is there will likely be long term downward pressure on prices as illustrated by the following quote from S&P Global:

> Long-term prospects for the region look increasingly dim as coal plants are retired by the nation's power generators, which are making no plans for new coal plants. A recent analysis by Market Intelligence found that 30.8% of coal deliveries shipped out of the Powder River Basin in 2019 went to coal plants that have already set retirement dates through 2042. Additional coal plants have been announced since, including several that buy coal from the Powder River Basin.[100]

**Q. Is Staff recommending a power cost dollar adjustment for the Dave Johnston plant?**

A. No. Not at this time. Staff Witness Ms. Rose Anderson's testimony sets forth a recommendation for future years (Staff/700, Issue 3).

## NAUGHTON

**Q. Please summarize the Company's filing regarding the Naughton plant.**

A. Fuel costs in the 2022 TAM decreased from $80.7 million to $24.4 million[101] and energy output decreased from **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** MWh[102] compared to the final 2021 TAM. However, the average cost increased from **[BEGIN CONFIDENTIAL]** [redacted]

[100] https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/powder-river-basin-coal-volumes-up-in-q3-but-below-year-ago-output-61167931, accessed June 3, 2021.
[100] https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/powder-river-basin-coal-volumes-up-in-q3-but-below-year-ago-output-61167931, accessed June 3, 2021.
[101] Staff Tables 5 and 6, above.
[102] *Id.*

[redacted] **[END CONFIDENTIAL]** per MWh.[103] The Company states that delivered coal costs per ton are expected to decrease by **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** based on preliminary discussions with the Kemmerer Mine.[104] The Company states that the primary reason for the cost decrease is environmental shortfall payments that are no longer included in the 2022 coal costs.[105]

**Q. Why does the average cost per MWh increase while coal costs are decreasing?**

A. The coal burn rate increased by **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** which entirely offsets the decrease in coal price.[106]

**Q. Is Naughton subject to a minimum take requirement?**

A. Yes, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** tons[107] which is equivalent to **[BEGIN CONFIDENTIAL]** [redacted].[108] **[END CONFIDENTIAL]** The Company states that iterative modeling was not necessary to meeting the minimum take requirement in 2022.[109]

**Q. What is the Naughton fuel use in the filed case?**

A. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** MMBtu which is nearly 60% less than the minimum take.[110]

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[103] *Id.*
[104] PAC/200, Ralston/19.
[105] *Id.*
[106] Staff Table 2 and Table 3, above.
[107] Staff/602, Fox/11 (PacifiCorp's response to Sierra Club Data Request 1.12 and Attach SC 1.12 CONF.xlsx).
[108] Staff/602, Fox/2 (PacifiCorp's response to Staff DR 71 and OPUC 71-2 CONF Attach.xlsb).
[109] Staff/602, Fox/1 (PacifiCorp's response to Staff DR 66).
[110] ORTAM22 NPC CONF.xlsm, percentage change calculated by Staff.

**Q. Is Staff recommending a power cost adjustment for the Naughton plant?**

A. No. Not at this time. Staff notes that adjusting up to the minimum take would increase 2022 power cost by approximately $6.9 million assuming that increased generation at Naughton would be displaced by other generation at the average cost for all resources.

## WYODAK

**Q. Please summarize the Company's filing regarding the Wyodak plant.**

A. Fuel costs in the 2022 TAM decreased from $27.6 million to $23.5 million[111] and energy output decreased from **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** MWh[112] compared to the final 2021 TAM. However, the average cost increased from **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per MWh.[113] The Company states that per ton coal costs have increased by approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** which is "primarily the result of escalation in diesel fuel and other contract indices."[114]

**Q. Please discuss the burn rate for this plant.**

A. The burn rate increases by **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** [115] which added nearly **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[116] to power costs.

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[111] Staff Tables 5 and 6, above.
[112] *Id.*
[113] *Id.*
[114] PAC/200, Ralston/19.
[115] Staff Table 3 above.
[116] Staff Table 2 above.

**Q. Does the filing include new supply contracts for this plant?**

A. No.

**Q. Is Wyodak subject to a minimum take requirement?**

A. Yes, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** tons[117] which is equivalent to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** MMbtu.[118] The Company states that iterative modeling was not necessary to meeting the minimum take requirement in 2022.[119] Fuel burned in the filed case is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** MMbtu[120] which is inexplicably nearly **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** below the contract minimum.[121]

**Q. Is Staff recommending a power cost adjustment for the Wyodak plant?**

A. Not at this time, however Staff notes that adjusting up to the minimum take would reduce 2022 power cost by approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** million assuming that increased generation at Wyodak would displace other generation at the average cost for all resources.

**<u>CRAIG</u>**

**Q. Please summarize the Company's filing regarding the Craig plant.**

A. Fuel costs in the 2022 TAM increased from $17.9 million to $19.1 million[122] and energy output increased from **[BEGIN CONFIDENTIAL]** [redacted]

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[117] Staff/602, Fox/11 (PacifiCorp's response to Sierra Club DR 1.12 and Attach SC 1.12 CONF.xlsx).
[118] Staff/602, Fox/2 (PacifiCorp's response to Staff DR 71 and OPUC 71-2 CONF Attach.xlsb).
[119] Staff/602, Fox/1 (PacifiCorp's response to Staff DR 66).
[120] Percentage change calculation calculated by Staff based on workpaper "ORTAM22 NPC CONF.xlsm."
[121] *Id.*
[122] Staff Tables 5 and 6, above.

[redacted] **[END CONFIDENTIAL]** MWh[123] compared to the final 2021 TAM. However, the average cost decreased from **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per MWh.[124] The Company states the reduction is primarily due to a reduction in overall mining costs at the Trapper mine.[125] The Company also asserts that the decision to enter into a new coal supply agreement with the Trapper mine is prudent.[126]

**Q. Does Staff agree with the Company's cost calculations?**

A. Generally, yes. Other than a small difference in unit fuel cost,[127] the Company's explanation is consistent with Staff calculated variances.[128] The prudence of the Trapper Mine agreement is addressed in the testimony of Staff witness Ms. Rose Anderson (Staff/700).

**Q. What are the Company's assertions regarding the benefits of owning the Trapper mine?**

A. In response to parties' inquiries, the Company states the following:

> Coal pricing under the new agreement with the affiliated Trapper mine for the Craig plant coal supply is also considered least-cost, least-risk. Due to mine ownership, coal is purchased at cost and a decision to forego Trapper coal for any other source could lead to increased cost of early closure and the acceleration of reclamation activities.[129]

[123] *Id.*
[124] *Id.*
[125] PAC/200, Ralston/22.
[126] PAC/200, Ralston/2; PAC/200, Ralston/9-10.
[127] The Craig plant fuel cost included in the final 2021 TAM is **[BEGIN CONFIDENTIAL]** $[redacted]/**[END CONFIDENTIAL]**MMBtu not $[redacted]/**[END CONFIDENTIAL]** MMBtu. Staff review of the Company's cost comparisons indicate the lower figure includes spot purchases.
[128] Staff Table 2 above.
[129] Staff/602, Fox/4 (PacifiCorp's response to Staff DR 73).

> The coal purchased from the affiliated Trapper mine can flex within a contractually specified range and will be determined based on the annual needs of the mine owners.[130]
>
> All decisions relating to the annual nomination and tonnage deliveries are made in accordance with the annual budgeting process and is reviewed and approved by the owners of the Trapper mine, in accordance with the Trapper CSA. The owners of the Trapper mine hold quarterly meetings with the mine to review mine plans, mine budgets, cost forecasts, and all other relevant information pertaining the operation of the mine.[131]

**Q. Is Staff recommending power cost dollar adjustments for the Craig plant?**

A. Not at this time. See the testimony of Staff Witness Ms. Rose Anderson (Staff/700, Issue 3) for Staff's recommendation regarding minimum take levels.

## COLSTRIP

**Q. Please summarize the Company's filing regarding the Colstrip plant.**

A. Fuel costs in the 2022 TAM decreased from $16.8 million to $14.5 million[132] and energy output decreased from **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** MWh[133] compared to the final 2021 TAM. However, the average cost increased from **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per MWh.[134] The Company states that the cost increase is "primarily due to an increase in the contract indices and to a lower volume of tier 2 coal being purchased."[135]

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[130] *Id.*
[131] Staff/602, Fox/13 (PacifiCorp's response to Sierra Club DR 1.30).
[132] Staff Tables 5 and 6, above.
[133] *Id.*
[134] *Id.*
[135] PAC/200, Ralston/22-23.

**Q. Does the filing include new supply contracts for this plant?**

A. No.

**Q. Is Colstrip subject to a minimum take requirement?**

A. Yes, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** tons[136] which is equivalent to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** MMbtu.[137] The Company states that iterative modeling was necessary to meeting the minimum take requirement in 2022.[138] Fuel burned in the filed case is **[BEGIN CONFIDENTIAL]** [redacted][139] **[END CONFIDENTIAL]** MMbtu which is slightly higher than the contract minimum.

**Q. Please discuss the price variance.**

A. Coal cost per ton increased **[BEGIN CONFIDENTIAL]** [redacted].[140] **[END CONFIDENTIAL]** The coal cost increase is somewhat offset by a lower burn rate resulting in a net increase in cost per MWh of **[BEGIN CONFIDENTIAL]** [redacted].[141] **[END CONFIDENTIAL]**

**Q. Is Staff recommending power cost adjustments for the Colstrip plant?**

A. No. Not at this time.

[136] Staff/602, Fox/11 (PacifiCorp response to Sierra Club DR 1.12 and Attach SC 1.12 CONF.xlsx).
[137] Staff/602, Fox/2 (PacifiCorp response to Staff DR 71 and OPUC 71-2 CONF Attach.xlsb).
[138] Staff/602, Fox/1 (PacifiCorp response to Staff DR 66).
[139] Workpaper "ORTAM22 NPC CONF.xlsm."
[140] PAC/200, Ralston/22
[141] Staff Table 4 above.

## HAYDEN

**Q. Please summarize the Company's filing regarding the Hayden plant.**

A. Fuel costs in the 2022 TAM decreased from $14.7 million to $11.4 million[142] and energy output decreased from **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** MWh[143] compared to the final 2021 TAM. However, the average cost increased from **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per MWh.[144] The Company states that "Under the terms of the January 1, 2018 reopener, the coal prices escalate on a fixed annual schedule from 2018 through 2022 and are no longer subject to market indices."[145]

**Q. Does the filing include new supply contracts for this plant?**

A. No.

**Q. Is Hayden subject to a minimum take requirement?**

A. Yes, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** tons[146] which is equivalent to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** MMbtu.[147] The Company states that iterative modeling was necessary to meeting the minimum take requirement in 2022.[148] Fuel burned in the filed case is **[BEGIN CONFIDENTIAL]** [redacted][149] **[END CONFIDENTIAL]** MMbtu which is slightly higher than the contract minimum.

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[142] Staff Tables 5 and 6, above.
[143] *Id.*
[144] *Id.*
[145] PAC/200, Ralston/22.
[146] Staff/602, Fox/11 (PacifiCorp response to Sierra Club DR 1.12 and Attach SC 1.12 CONF.xlsx).
[147] Staff/602, Fox/2 (PacifiCorp response to Staff DR 71 and OPUC 71-2 CONF Attach.xlsb).
[148] Staff/602, Fox/1 (PacifiCorp response to Staff DR 66).
[149] Workpaper "ORTAM22 NPC CONF.xlsm."

**Q. Does Staff have concerns with PacifiCorp's forecast of Hayden dispatching at a minimum take level?**

A. No. The average cost per MWh for Hayden is well above the system average coal fuel cost and also higher than the average cost per MWh for all resources in 2022. Operation at the minimum level benefits ratepayers.

**Q. Is Staff recommending power cost adjustments for the Colstrip plant?**

A. No, not at this time.

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

A. Yes.

CASE: UE 390
WITNESS: JOHN FOX

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

## STAFF EXHIBIT 601

## Witness Qualifications Statement

**June 9, 2021**

**WITNESS QUALIFICATIONS STATEMENT**

| | |
|---|---|
| NAME: | John L. Fox |
| EMPLOYER: | Public Utility Commission of Oregon |
| TITLE: | Senior Financial Analyst<br>Energy Rates, Finance and Audit Division |
| ADDRESS: | 201 High Street SE. Suite 100<br>Salem, OR. 97301 |
| EDUCATION: | I hold a Bachelor of Science degree in Business Administration / Accounting from the University of Oregon (1989). I also completed the Certificate in Public Management program at Willamette University (2010).<br><br>I have been licensed as a Certified Public Accountant in Oregon since 1991. Maintaining active status has required a minimum of 80 hours continuing professional education every two years. |
| EXPERIENCE: | From 1989 to 1999 I was in general practice with several CPA firms in Southern Oregon and the Mid-Willamette Valley. My tax experience includes individuals, trusts and estates, qualified retirement plans, and extensive corporate, partnership, and LLC work. Accounting experience during this time includes client write up, compilation and review, and significant audit and attest work.<br><br>I have been employed in the executive branch of Oregon state government since 1999. My experience prior to joining the Commission staff includes 3 years as a cost accountant, 11 years as a senior budget analyst, and 4 years in an oversight role as a budget team lead.<br><br>I have extensive experience in capital construction and financing, complex cost modeling, rate development, fiscal projections, expenditure analysis, and cost control for programs with biennial revenues between $100 million and $300 million. |
| PRIOR DOCKETS: | I have provided testimony as a Staff witness in the following OPUC proceedings; UE 335, UE 374, UG 344, UG 347, UG 366, UG 388, UG 389, UG 390, UM 1992, UM 2004, UM 2026. |

CASE: UE 390
WITNESS: JOHN FOX

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 602

## Exhibits in Support
## Of Opening Testimony

## June 9, 2021

UE 390 / PacifiCorp
May 7, 2021
OPUC Data Request 66

**OPUC Data Request 66**

Please refer to PAC/100, Webb/30. Regarding the statement "iterative GRID runs may be necessary to ensure that coal burn volumes are consistent with minimum take requirements across the coal fleet":

(a) Please identify the number of iterative runs underlying the filed coal fuel burn expense of $543.4 million found in PAC/102, Webb/5and identify the work papers where the iterations can be found.

(b) Please provide a narrative explanation of how removal of the "must run" setting has affected the iterative process.

(c) Please identify any coal units which cleared their respective minimum purchase obligations without iterative adjustment of the incremental coal price input.

**Response to OPUC Data Request 66**

(a) The iterative runs are not processed into reports that can be provided since the net power costs (NPC) are both preliminary and incomplete (only the annual fuel consumption totals are evaluated). Typically, there are somewhere between five and 20 iterative runs, given that the goal is to achieve a forecasted fuel consumption very close to the minimum purchase obligation at several plants, and that there is a certain amount of switching between units that has to be accounted for when adjusting the prices.

(b) The effect is no different than the effect of any other change to a constraint. The process itself and the goal of that process both remain the same.

(c) In the initial filing of the 2022 transition adjustment mechanism (TAM), the coal units requiring adjustment to meet the minimum take obligation are Colstrip, Hayden, and Huntington. The Craig, Dave Johnston, Hunter, Jim Bridger, Naughton, and Wyodak coal units required no adjustment.

UE 390 / PacifiCorp
May 7, 2021
OPUC Data Request 71

**OPUC Data Request 71**

Please refer to PAC/200, Ralston/5. Regarding the statement "The negotiations for the new agreements were based upon a generation forecast that was part of the overall fueling budget for the Company":

(a) Please provide a narrative explanation of how the overall fueling budget is developed and its relationship to the annual TAM filing.

(b) Please provide a copy of the 2022 overall fueling budget or reference where it can be found in the TAM work papers.

**Response to OPUC Data Request 71**

(a) PacifiCorp's finance department calculates net power costs (NPC) over the 10-year business planning horizon based on projected data using the Generation and Regulation Initiative Decision Tool (GRID). The overall fueling budget is developed by obtaining the thermal availability including planned maintenance, variable operation and maintenance (O&M) unit costs, minimum load levels and heat rate input/output curves from thermal plant management. Incremental fuel costs and minimum take constraints are obtained, including volumes available at those incremental prices. PacifiCorp loads the data into GRID and runs the model using these inputs. These results are reviewed for reasonableness by comparing them to expected targets based on historical coal generation volumes adjusted for forecasted changes in load, anticipated system resources, renewables, and plant retirements.

The business planning generation forecast is run for a different purpose and at a different time of year than GRID runs for ratemaking purposes such as the transition adjustment mechanism (TAM). The purpose of the business plan GRID run is to try to capture recent market trends and volatility that could impact the forecast year whereas the ratemaking GRID runs try to capture more normalized results. The costs associated with the new coal supply agreements (CSA) that were negotiated and signed using the reviewed GRID results are included in the TAM.

(b) Please refer to Confidential Attachment OPUC 71-1 and Confidential Attachment OPUC 71-2, which provide the generation forecast that was used when negotiating and signing the new agreements. This includes the PacifiCorp's overall fueling budget that was relied upon for those new agreements.

UE 390 / PacifiCorp
May 7, 2021
OPUC Data Request 71

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

UE 390 / PacifiCorp
May 7, 2021
OPUC Data Request 73

**OPUC Data Request 73**

Please refer to PAC/200, Ralston/10. Regarding the statement "The new contracts ensure that customers will receive the lowest price coal available, that plants will be dispatched economically in the near-term, and that the Company retains as much flexibility as possible," please provide evidence to support these assertions.

(a) Lowest price coal available.

(b) Plants will be dispatched economically in the near-term.

(c) Company retains as much flexibility as possible.

**Response to OPUC Data Request 73**

(a) Coal pricing under the new coal supply agreements for the Dave Johnston and Hunter plants' fuel supply were obtained through a competitive request for proposals process. Potential coal sources were invited to participate and provide bids in this process. The company then executed agreements with entities that provided the least-cost, least-risk proposals. Coal pricing under the new agreement with the affiliated Trapper mine for the Craig plant coal supply is also considered least-cost, least-risk. Due to mine ownership, coal is purchased at cost and a decision to forego Trapper coal for any other source could lead to increased cost of early closure and the acceleration of reclamation activities.

(b) Coal pricing under the new coal supply agreements generally declined (and in some cases significantly declined) which improves the individual plant's dispatch position in comparison to other market alternatives.

(c) In the case of the two new Hunter agreements, the price of coal declined substantially with no increase in minimum take commitment. There was no change to the minimum take commitment under the Dave Johnston agreements, Powder River Basin agreements are typically take-or-pay. The coal purchased from the affiliated Trapper mine can flex within a contractually specified range and will be determined based on the annual needs of the mine owners.

UE 390 / PacifiCorp
May 21, 2021
OPUC Data Request 113

**OPUC Data Request 113**

**CONFIDENTIAL REQUEST - Coal Fuel Burn Expense**
Regarding details in the filed case (ORTAM22 NPC CONF) and the 2021 final TAM (_Final ORTAM21 Fin Nov NPC CONF -TB and Pryor Constant):

(a) Please provide a detailed narrative explanation of the operational reasons underlying the year over year variances in burn rate for each coal plant summarized in the following table:

**[CONFIDENTIAL BEGINS]**

| | 2021 | 2022 | % Chg. |
|---|---|---|---|
| Colstrip | [redacted] | [redacted] | [redacted] |
| Craig | [redacted] | [redacted] | [redacted] |
| Dave Johnston | [redacted] | [redacted] | [redacted] |
| Hayden | [redacted] | [redacted] | [redacted] |
| Hunter | [redacted] | [redacted] | [redacted] |
| Huntington | [redacted] | [redacted] | [redacted] |
| Jim Bridger | [redacted] | [redacted] | [redacted] |
| Naughton | [redacted] | [redacted] | [redacted] |
| Wyodak | [redacted] | [redacted] | [redacted] |

**[CONFIDENTIAL ENDS]**

(b) Please explain why the burn rate for the Wyodak plant appears to be structurally higher than the other plants.

**Confidential Response to OPUC Data Request 113**

(a) All of the changes to the burn rates (heat rates) are forecast values for both 2021 and 2022. These are based on historical performance, and adjusted for future years based on degradation, maintenance schedules, and generation levels. The average annual forecast burn rates are calculated using curves developed to cover the entire load range. Heat rates are typically best at loads above 85 percent and increase for lower loads. The heat rate, or burn rate, for 50 percent load is about 5 percent to 10 percent higher than the unit's best efficiency point. At 10 percent of maximum load, heat rate can increase by 50 percent, however since the load is reduced it will affect the average annual heat rate by a lesser amount.

Please refer to the information below for each of the plants listed in the table above:

Docket No. UE 390

UE 390 / PacifiCorp
May 21, 2021
OPUC Data Request 113

**[CONFIDENTIAL BEGINS]**

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

UE 390 / PacifiCorp
May 21, 2021
OPUC Data Request 113

[redacted]

**[CONFIDENTIAL ENDS]**

(b) Wyodak utilizes an air-cooled condenser. It is the only coal-fired unit in the fleet with this type of condenser. The air-cooled condenser is less efficient at cooling the steam passing through the turbine than a cooling tower or a once through water cooled condenser. Therefore, the turbine was designed to operate at a higher backpressure. This higher backpressure decreases the total available energy that can be extracted from the steam and decreases the efficiency of the unit by design

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

UE 390 / PacifiCorp
May 7, 2021
Sierra Club Data Request 1.2

**Sierra Club Data Request 1.2**

For each of the Company's coal units please provide the following cost characteristics by month from January 2019 through the present. If not using the units as per below, indicate the units for each characteristic.

(a) Hourly Net generation (MWh).

(b) Operational or maximum available capacity (MW).

(c) Minimum economic available capacity (MW).

(d) Heat rate (MMBtu/MWh).

(e) Fixed operations and maintenance (O&M) costs (total $).

(f) Variable O&M costs (not including fuel cost) ($/MWh).

(g) Variable fuel cost – dispatch tier ($/MWh).

(h) Variable fuel cost – costing tier ($/MWh).

(i) Fixed fuel cost ($).

(j) Any non-capital coal unit cost not included in the above categories ($).

(k) Any capital coal unit cost not included in the above categories ($).

(l) Please explain the use of different dispatch tiers in GRID and provide a description of the cost elements included in each of the above cost categories.

**Response to Sierra Club Data Request 1.2**

(a) Please refer to Confidential Attachment SC 1.2-1, which provides actual hourly generation for PacifiCorp's coal-fuel generation plants for calendar years 2019 and 2020, and 2021 (January 2021 through March 2021). Note: calendar year 2021 information is preliminary, subject to change.

(b) PacifiCorp will supplement this response with the appropriate information by May 12, 2021.

(c) PacifiCorp will supplement this response with the appropriate information by May 12, 2021.

UE 390 / PacifiCorp
May 7, 2021
Sierra Club Data Request 1.2

(d) Please refer to Confidential Attachment SC 1.2-4.

(e) PacifiCorp objects to this request on the grounds that the information sought is outside the scope of this proceeding and that this request is not reasonably calculated to lead to the discovery admissible evidence. Fixed operations and maintenance costs for the company's coal plants are not included in the Company's net power costs (NPC) and are therefore not relevant to the transition adjustment mechanism (TAM) proceeding.

(f) Please refer to Confidential Attachment SC 1.2-4.

(g) Please refer to Confidential Attachment SC 1.2-4.

(h) Please refer to Confidential Attachment SC 1.2-3.

(i) PacifiCorp objects to this request on the grounds that it is vague and ambiguous. It is unclear to the Company what the term "fixed fuel cost ($)" refers to. The Company assumes that the intended reference to "fixed fuel costs ($)" is intended to request coal fuel costs that PacifiCorp considers unavoidable. Based on the foregoing assumption, the Company responds as follows:

The minimum volumes that are required for purchase are based upon an annual purchase amount over the contract year. Please refer to the Company's response to Sierra Club Data Request 1.12, specifically Confidential Attachment SC 1.12 which provides annual contract volume minimums for coal supplies and transportation. PacifiCorp does not track actual fuel cost by contractual minimum and additional coal, but by total volume delivered

(j) PacifiCorp objects to this request on the grounds that it is vague and ambiguous. It is unclear what the term "non-capital coal unit cost" refers to. The Company assumes that the intended reference to "non-capital coal unit cost" is intended to request any coal unit costs not categorized by the Company as either "capital costs" or "O&M costs" (whether variable or fixed). Based on the foregoing assumption, the Company responds as follows:

All coal costs have been provided in the categories above.

(k) PacifiCorp objects to this request on the grounds that the information sought is outside the scope of this proceeding and that this request is not reasonably calculated to lead to the discovery of admissible evidence. Capital costs are not included in the Company's NPC and are therefore not relevant to the current TAM proceeding.

UE 390 / PacifiCorp
May 7, 2021
Sierra Club Data Request 1.2

(l) The Generation and Regulation Initiative Decision Tool (GRID) utilizes two different price tiers in the modeling of the Company's thermal plants; the (1) "dispatch tier," and the (2) "costing tier."

(1) The "dispatch tier" costs are the incremental costs to operate PacifiCorp's coal plants. The incremental cost is the change in cost to generate additional generation from each power plant. The incremental costs include the cost to purchase additional fuel, the incremental heat rate (efficiency) to operate the plant, and the variable operations and maintenance expense. GRID dispatches individual resources on a marginal or incremental cost basis, to optimize the dispatch of the Company's existing system in the most economic manner while accounting for system constraints.

(2) The "costing tier" is the average annual unit price for fuel expense. The average cost of coal includes all of the cost of coal purchased under existing coal supply agreements or from company mining operations. GRID uses the costing tier price multiplied by the coal volumes to arrive at the total coal fuel expense.

Confidential information is provided subject to Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

UE 390 / PacifiCorp
May 7, 2021
Sierra Club Data Request 1.12

**Sierra Club Data Request 1.12**

For each coal contract (including affiliated mines) held and in force by the Company:

(a) Identify the mine or supplier of the coal.

(b) Identify the plant(s) to which the coal is delivered.

(c) Identify if the contract is take-or-pay, liquidated damages, or fully variable. If the contract takes another form that is functionally different than take-or-pay, liquidated damages, or variable cost, specify the form of the contract and provide a note describing the contractual obligation.

(d) Specify the minimum tonnage requirement, or any tier volume constraints.

(e) Specify the coal price in $/ton, including any tiers or other pricing structure.

(f) Specify the coal heat content.

(g) Identify the state and end date of each contract.

**Response to Sierra Club Data Request 1.12**

(a) Please refer to Confidential Attachment SC 1.12 which provides a summary table providing coal supply agreements (CSA) and transportation contracts listing supplier or transporter, plant, contract type (take-or-pay, liquidated damages, etc.), state, term end, and minimum tonnage requirement.

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

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

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

(e) Please refer to the Company's response to Sierra Club Data Request 1.8.

(f) Please refer to the Company's response to Sierra Club Data Request 1.8.

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

UE 390 / PacifiCorp
May 7, 2021
Sierra Club Data Request 1.12

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

UE 390 / PacifiCorp
May 7, 2021
Sierra Club Data Request 1.30

**Sierra Club Data Request 1.30**

For PacifiCorp's jointly-owned coal mines supplying the Company's coal plants, describe how the Company coordinates with its co-owners to make decisions regarding whether to include take-or-pay or liquidated damages provisions in the applicable coal supply contracts. Identify the specific coal mines and the plants supplied for which the Company's process applies.

**Response to Sierra Club Data Request 1.30**

The Trapper Mine is an affiliated mine that provides coal to PacifiCorp's ownership interest in Craig Unit 1 and Craig Unit 2 at the Craig Station. PacifiCorp has 29.14 percent interest in the Trapper Mine. There are no "take-or-pay or liquidated damage provisions in the Trapper coal supply agreement (CSA). The Trapper CSA has a flexible annual nomination range for tonnage volumes. All decisions relating to the annual nomination and tonnage deliveries are made in accordance with the annual budgeting process and is reviewed and approved by the owners of the Trapper mine, in accordance with the Trapper CSA. The owners of the Trapper mine hold quarterly meetings with the mine to review mine plans, mine budgets, cost forecasts, and all other relevant information pertaining the operation of the mine.

Bridger Coal Company (BCC) is an affiliate mine, owned 66.7 percent by Pacific Minerals Inc. (PMI), a subsidiary of PacifiCorp, and owned 33.3 percent by Idaho Energy Resources Co. (IERCO), a subsidiary of Idaho Power Company (IPC). In addition to the mine ownership, PacifiCorp owns 66.7 percent of the Jim Bridger plant and is also the operator of the plant, while IPC owns the remaining 33.3 percent share of the plant. Bridger Coal provides coal under a long-term CSA to the Jim Bridger plant. The CSA remains in effect to facilitate business transaction with Bridger Coal's joint owner, IPC. All mine operation decisions such as mine planning, annual production levels, annual coal deliveries, budgeting, capital acquisitions, reclamation, personnel, permitting, etc. are made by the Mine Management Committee which consists of representatives from PacifiCorp, IPC and BCC's leadership team. The Mine Management Committee holds regular meetings with Bridger Coal to discuss and approve decisions being executed by the BCC. Decisions made by the Mine Management Committee ultimately benefit the plant owners by providing additional flexibility in terms of coal production, coal deliveries, and total costs to the plant.

UE 390 / PacifiCorp
June 1, 2021
Sierra Club Data Request 2.17

**Sierra Club Data Request 2.17**

During the May 14, 2021 Staff Workshop, PacifiCorp stated that the informational average cost GRID run: uses average costs to dispatch the units; after the optimal dispatch and fuel consumption were determined by the model, the fuel consumption level is used to recalculate total and average fuel costs (reflecting contractual pricing structure and obligations); and an additional run with the average cost is performed. With respect to that informational run:

(a) Please confirm or deny the steps identified above and provide any additional detail that is not captured, including PacifiCorp's reasoning behind this iterative methodology.

(b) Please provide the average costs that are used as an input of the first run and explain how they are derived for each coal plant, particularly for coal plants with multiple coal supply agreements and/or multiple pricing tiers;

(c) Please provide the dispatch level of each coal plant from the first run;

(d) Please provide the coal burn expenses of the first run prior to including the take-or-pay penalties or liquidated damages;

(e) Please identify the take-or-pay penalties or liquidated damages associated with each coal supply agreement;

(f) Please provide the average cost values after they have been re-calculated and used as input for the second run;

(g) Please provide the dispatch level and coal burn expenses of the second run and confirm that these are the final ones (included in the work paper of the informational run, zz_ORTAM22_Avg Fuel Cost Final CONF);

(h) Please explain whether the penalty associated with reducing fuel consumption at the Jim Bridger plant is associated with the Bridger Coal Company or Black Butte contract and why;

(i) Please explain how would the coal burn expense would change if coal consumption was reduced from the Bridger Coal Company;

(j) Please confirm that total NPC would be lower if the reduction in the Jim Bridger coal consumption in the average cost run was not assumed to trigger a take-or-pay minimum from Black Butte, but rather reduced coal consumption from the Bridger coal mine.

UE 390 / PacifiCorp
June 1, 2021
Sierra Club Data Request 2.17

**Confidential Response to Sierra Club Data Request 2.17**

(a) Confirmed.

(b) Please refer to the Confidential Attachment SC 2.17 for the fuel prices used as "costing tier" prices in the run described in the first step of the process as outlined above ("uses average costs to dispatch the units"). The costs are based on average (costing tier) prices in the run that produced "ORTAM22 NPC CONF.xlsm," which was included in the concurrent work papers in this proceeding.

(c) Please refer to the dispatch level provided in file "zz_ORTAM22_Avg Fuel Cost Final CONF," which was referred to in subpart g of this request. The costing tier price has no impact on the Generation and Regulation Initiative Decision Tool's (GRID) dispatch, therefore the burns are unchanged after the re-averaging.

(d) Please refer to the final coal costs provided in file "zz_ORTAM22_Avg Fuel Cost Final CONF." That is the only run that includes the requested cost components.

(e) The take-or-pay penalties and liquidated damages for the average cost dispatch study are as follows:

Colstrip **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]** in liquidated damages.

Huntington **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]** in take-or-pay penalties.

(f) Please refer to the Confidential Attachment SC 2.17 (tab "Subpart f").

(g) Confirmed. Please refer to file "zz_ORTAM22_Avg Fuel Cost Final CONF," which includes both dispatch levels and expenses.

(h) There is no penalty associated with the reduced fuel consumption at the Jim Bridger plant. The cost increases are due to the reduced volume of coal delivered from Bridger Coal Company (BCC). There was also a reduction of coal purchased from Black Butte mine in the average cost dispatch study, as there is no contract for 2022 from Black Butte mine, there were no liquidated damages associated with this reduction. The average cost dispatch study does a have the deferred tons from the Black Butte mine from 2021 to 2022.

(i) Please refer to the Company's response to subpart (h) above.

(j) Denied. Please refer to the Company's response to subpart (h) above. There is no assumption of any liquidated damages from Black Butte mine in this study.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

CASE: UE 390
WITNESS: Rose Anderson

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 700

# Opening Testimony

**June 09, 2021**

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

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

**Q. Please describe your educational background and work experience.**

A. My witness qualification statement is found in Exhibit Staff/701.

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

A. The purpose of my testimony is to present Staff's analysis of the Economic Coal Cycling Study and the economics of PacifiCorp's recent coal contract minimum take levels.

**Q. Did you prepare any exhibits for this docket?**

A. Yes. In addition to Exhibit Staff/701, I prepared Exhibit Staff/702 (PacifiCorp's responses to Data Requests) and Exhibit Staff/703 (PacifiCorp's confidential responses to Data Requests).

**Q. How is your testimony organized?**

A. My testimony is organized as follows:

## ISSUE 1, ECONOMIC COAL CYCLING STUDY

**Q. Please provide a background on PacifiCorp's Economic Coal Cycling Study (Coal Cycling Study or Study.)**

A. In the Stipulation in Docket No. UE 375 (2021 TAM), PacifiCorp agreed to provide a study on "the costs and benefits of economic cycling including the non-fuel cost impacts by March 1, 2021."[1] In Opening Testimony PacifiCorp reports that it sent a copy of its completed Study to parties to the 2021 TAM.[2] PacifiCorp has also included a copy of its Coal Cycling Study as an attachment to the testimony of David G. Webb.[3]

**Q. Please summarize the Coal Cycling Study.**

A. The Coal Cycling Study is based on a GRID model run using the input data from the 2021 TAM. In the Study, "must run" assumptions for all of the Company's coal plants have been turned off, allowing the coal units to cycle off whenever GRID expects that their operation would be uneconomic. The study finds that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** However, PacifiCorp reports that the generation plan resulting from this model run could not be reliably used to serve load, since it includes an unrealistic number of emergency purchases.[4]

[1] UE 375 - Stipulation at 8.
[2] PAC/100, Webb/14.
[3] PAC/107.
[4] PAC/100, Webb/14.

Emergency Purchases in GRID, PacifiCorp explains, "are the result of modeling resource shortages and occur when resources in an area of the Company's system are fully dispatched, and / or transmission into the area is insufficient to meet the load in that area."[5] In Opening Testimony, PacifiCorp reports that, in the Coal Cycling Study, "Since emergency purchases are not actual transactions available to the Company, the modeling result reflected a solution that did not reflect actual operations and could not reliably serve load."[6]

**Q. What is Staff's reaction to the Coal Cycling Study?**

A. Staff would like to share two reactions to the Study. First, Staff appreciates the Company's work on the Study and considers it a step toward determining whether PacifiCorp could reduce power costs for customers by cycling its coal plants. However, the study is inadequate for identifying whether economic cycling at one or more coal units may be able to create savings for customers through the reduction of annual net power costs. PacifiCorp has a responsibility to its customers to look further into this possibility. The results of the Study, along with the generally unfavorable market environment for coal generation, indicate that cycling one or more coal unit(s) off **[BEGIN CONFIDENTIAL]** [redacted], **[END CONFIDENTIAL]** may prove to be a reasonable course of action.

[5] Staff/702, Anderson/1. (PacifiCorp's response to Staff DR 61).
[6] PAC/100, Webb/14.

Second, Staff has an unresolved question regarding the quantity of emergency purchases in the Study, as compared to the 2022 TAM. Staff's understanding of the Coal Cycling Study is that it turned off "must run" assumptions for coal units and kept all other assumptions the same as in the 2021 TAM. The result was **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** as compared to the 2021 TAM. [7] However, in the 2022 TAM, making the same adjustment by turning off the "must run" setting has apparently only resulted **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in emergency purchases as compared to the counterfactual study with "must run" turned on.[8,9] Staff is uncertain why the change in emergency purchases resulting from turning off the "must run" setting would be so dramatically different in the 2022 TAM, as compared to the Economic Coal Cycling Study just one year earlier.

Staff's hypothesis is that the dramatic improvement in emergency purchases in the 2022 TAM may be a result of the changes in GRID assumptions made in the 2022 TAM and described in PacifiCorp's Opening Testimony.[10] If this hypothesis is correct, then the Company has already shown that the Economic Coal Cycling Study can easily be improved with a few modeling changes already implemented in the 2022 TAM.

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[7] PAC/107, Webb/2.
[8] PAC/102, Webb/4.
[9] Staff/703. PacifiCorp workpaper "SL02 ORTAM22_xCoal Cycling CONF"
[10] PAC/100, Webb/15-16.

**Q. What is Staff's recommendation regarding economic cycling moving forward?**

A. PacifiCorp should perform a follow-up study that seeks to identify potential cost savings from economic coal cycling as part of a reliable generation plan.

**Q. Why is a follow-up study warranted?**

A. While Staff appreciates the modeling performed by the Company in this initial Study, it is not a full and rigorous treatment of economic cycling opportunities. A follow-up Economic Cycling Study is essential to understanding whether economic cycling at one or more additional coal units is a reasonable way to create savings for customers. The existing Coal Cycling Study does not provide an answer to this important question.

**Q. Do you have a specific recommendation regarding the future modeling?**

A. Yes. The Coal Cycling Study allowed any coal unit to cycle off at any time, resulting in an unreasonably high amount of emergency purchases in GRID.[11] A next step toward identifying economic cycling opportunities should be to look into economic cycling in a way that meets the requirements of a reliable generation plan. This could be done by reducing the number of coal units that are allowed to cycle off at a given time, by looking for available short-term capacity contracts or other resources that can provide shoulder season capacity at a lower cost than coal, and/or by utilizing a new model that is able to consider reliability in its economic cycling decisions. PacifiCorp's reply to

[11] PAC/100, Webb/14.

Staff DR 165 indicates that the AURORA model may be able to consider reliability when economically cycling units.[12]

**Q. What if this model is not capable of identifying units for economic cycling?**

A. If PacifiCorp cannot find a model capable of considering reliability while identifying which coal units to cycle, then PacifiCorp could reduce the number of plants that are considered for cycling off at any given time. PacifiCorp could evaluate economic cycling only for the unit(s) or plant(s) that are expected to provide the least value to the system during shoulder months. Value to the system could be estimated by considering multiple factors including ramp rate, total ramping ability in MW, variable operating costs, ancillary services, and historical EIM revenues.

**Q. Please summarize your recommendation.**

A. PacifiCorp should perform a follow-up economic cycling study that seeks to identify additional opportunities for cost savings through economic coal cycling. Following the conclusion of the 2022 TAM, PacifiCorp should be required to both solicit feedback from Staff and other interested stakeholders and then complete a follow-up study prior to the next TAM.

[12] Staff/702, Anderson/2.

## ISSUE 2: MINIMUM TAKE LEVELS IN PACIFICORP'S NPC FORECAST

**Q. In the final Order in the 2021 TAM, the Commission requested that parties discuss whether minimum take levels should be included in power cost modeling, or should be removed to allow coal plants to generate at levels more consistent with market dynamics. What is Staff's position regarding modeling of minimum take levels in power cost dockets?**

A. Generally speaking, minimum take levels are creatures of contract, and therefore, should be reflected in rates to the extent that the contract itself is prudent. If a minimum take contract provision in a coal supply agreement is not prudent, then Staff finds that it would be appropriate to remove that minimum take level from power cost modeling as one possible remedy to the Company's imprudence for entering into the contract. However, in general, minimum take levels are actual constraints that the Company faces, and if they were prudently agreed to, they should be included in power cost modeling.

Staff does not advocate for exclusion of most historical coal contract minimum take levels in PacifiCorp's NPC forecast at this time, with the exception of the Huntington contract and some of the new coal contracts.

As discussed further below, my testimony recommends removing minimum take assumptions from the coal modeling associated with three of the five new coal contracts in the 2022 TAM,[13] as well as the most recent Huntington

[13] A total of five coal contracts are included for review for the first time in this TAM for coal supply to Dave Johnston, Hunter and Craig.

contract,[14] based on the Company's failure to demonstrate that it appropriately analyzed minimum take levels when determining whether and to what extent to enter into coal supply agreements with minimum take provisions.

[14] The Huntington coal contract was introduced by the Company in UM 1712, although the Commission declined to consider the reasonableness of the contract in that proceeding.

**ISSUE 3: MINIMUM TAKE PROVISIONS IN PACIFICORP'S COAL CONTRACTS**

**Q. Please explain what a minimum take requirement is.**

A. A minimum take requirement, or 'take or pay' agreement, is a contractual agreement to purchase a certain amount of coal or else pay full price for the coal, even if it's not delivered.[15] These agreements change the economics of coal generation by setting the incremental cost of coal burned at zero until the minimum take level is reached.[16] This is because a specific quantity of coal is effectively paid for ahead of time, before the Company knows whether it will be needed for generation. In PacifiCorp's Opening Testimony, the Company states that nearly all coal contracts include minimum take requirements because without them, a coal supplier would be required to make a large investment with no assurance that it would sell any coal.[17]

Another interesting quality of the take or pay agreements in PacifiCorp's recent contracts at Dave Johnston, Hunter, Craig, and Huntington is that they **[BEGIN HIGHLY CONFIDENTIAL]** [redacted]

[15] Staff/702, Anderson/3. (PacifiCorp's response to Sierra Club DR 1.5).
[16] Ibid.
[17] PAC/200, Ralston/6.

[redacted][18] **[END HIGHLY CONFIDENTIAL]**

**Q. How has PacifiCorp modeled minimum take requirements in GRID?**

A. When a unit fails to generate at or above its minimum take level in the initial GRID run, PacifiCorp has explained that it must adjust the coal cost input downward at that unit and iteratively re-run the model until the model selects generation levels consistent with minimum take levels.[19] For example, this iterative adjustment process was required to bring generation levels for Colstrip, Hayden, and Huntington up to minimum take levels in the 2022 TAM modeling.[20]

**Q. Please describe how PacifiCorp determined minimum take levels in its new coal contracts and the Huntington coal supply agreement.**

A. PacifiCorp has explained in its Opening Testimony, and in subsequent discovery responses, that its coal contract negotiations around minimum take levels are informed by generation forecasts that are "part of the overall fueling budget for the company."[21] Additionally, the Company has explained that, before it is used in contract negotiations, this fueling budget forecast is 'reviewed for reasonableness' by comparing it to 'expected targets' which are

[18] Staff was able to review the coal contracts but not to make copies or take verbatim notes.
[19] PAC/100, Webb/30.
[20] Staff/702, Anderson/5. (PacifiCorp's response to Staff DR 66).
[21] PAC/200, Ralston/5.

based on historical generation volumes, adjusted for "expected changes in load, anticipated system resources, renewables, and plant retirements."[22,23]

**Q. What are Staff's concerns about PacifiCorp's contract negotiations around minimum take levels?**

A. After reviewing discovery responses from PacifiCorp, Staff is concerned because, although the business plan generation forecast looks 10 years into the future, the response to one of Staff's data requests indicates that the generation forecasts used to support minimum take decisions at the new coal contracts do not look more than **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** years into the future.[24,25] Additionally, as discussed in my testimony below, the forecasts mostly appear not to adequately consider **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Staff has general concerns about the fueling budget generation forecast being used to support PacifiCorp's coal contract negotiations. Staff is doubtful that the forecast as used to inform negotiations and the 'review for reasonableness' described by PacifiCorp are rigorous enough to determine the best minimum take level for a given unit over the entire duration of a coal contract.

[22] Staff/702, Anderson/6. (PacifiCorp's response to Staff DR 71).
[23] Staff/702, Anderson/8. (PacifiCorp's response to Staff DR 157).
[24] Staff/702, Anderson 6. (PacifiCorp's response to Staff DR 71).
[25] Staff/703. (Attachments to PacifiCorp's response to Staff DR 71).

Staff finds that, especially given the uncertain economics of coal, any modeling that informs contract negotiations needs to be performed with the sole intention of identifying the optimal generation levels for a plant over the expected contract term. The use of the fueling budget generation forecast does not seem to fit this purpose.

**Q. What is Staff's recommendation regarding the coal generation forecasts used to inform coal contract negotiations?**

A. In order to show that any minimum take levels included in a coal supply agreement are prudent, PacifiCorp must show that it has thoroughly evaluated the most economic levels of coal generation, including economic cycling possibilities, prior to and while engaging in coal contract negotiations around minimum take levels. This prevents ratepayers from incurring costs unnecessarily when PacifiCorp's minimum take provisions cause its coal units to dispatch at times that would otherwise be uneconomic. Therefore, if PacifiCorp cannot demonstrate during the 2022 TAM that its forecasts meet the following requirements, the Company should make improvements to its generation forecast used to inform coal contract negotiations.

The forecast used to inform negotiations should:

1. Cover the entire duration of a coal contract,
2. Include the resource buildout from the Company's most recent Integrated Resource Plan, and
3. Consider opportunities to create savings for customers by cycling coal units or plants off during the off-peak season. This could be done by

including the results of a recent economic cycling study into the forecast, or by creating the forecast in a model that can effectively consider economic cycling.

Prior to designing an updated forecasting methodology, PacifiCorp should participate in discussion(s) with Staff and stakeholders and accept suggestions for implementing the improvements.

After developing a forecasting methodology with these improvements, and before the filing of the next TAM, the Company should provide a stakeholder workshop explaining in detail how the forecasting methodology has been improved. Finally, the next TAM filing should provide a summary of this process and the improved methodology.

## DAVE JOHNSTON, HUNTER, AND CRAIG COAL CONTRACTS

**Q. What are the new coal contracts included in this TAM?**

A. PacifiCorp has included in the 2022 TAM a total of five new coal supply agreements for its Dave Johnston, Hunter, and Craig plants. A more detailed summary of these contracts can be found in PacifiCorp's Opening Testimony, and in the testimony of Staff Witness Mr. John Fox (Staff/600, Issue 2).[26]

**Q. What is Staff's position on the contract length and minimum take levels of these new contracts?**

A. Generally speaking, Staff is supportive of limiting coal contract length. Shorter contract length provides flexibility for the operation of the coal units, and provides one way to reduce the risk of these contracts to customers.

Regarding minimum take levels, the analysis that informed these contract decisions generally suffers from the same problems identified by Staff above. Staff does not find evidence that PacifiCorp has engaged in a robust analysis seeking to identify economic generation levels for each of the plants for the duration of the coal contracts, and considered that forecast prior to and during negotiating the contracts, which include minimum take provisions. In fact, based on the Company's fueling budget generation forecast workbooks provided to Staff, forecasts that informed negotiations for several of the contracts do not appear to look **[BEGIN CONFIDENTIAL]** [redacted]

[26] PAC/200, Ralston/2-10.

[redacted].[27,28] **[END CONFIDENTIAL]**

The fueling budget generation forecast that PacifiCorp used to support its negotiations around the new coal contracts does not appear suited to the job of identifying optimal economic generation levels for the coal plants for years to come. This is unacceptable. The Company should be seeking to reduce power costs for customers with its minimum take agreements.

Further, upon review of the coal contracts, Staff noted that **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** Staff is continuing to investigate this contract feature, and is concerned that it is not supported by the workpapers provided in recent discovery responses.

**Q. What is your assessment of minimum take levels in the Dave Johnston contract?**

A. PacifiCorp's Dave Johnston contract is a perfect example of Staff's concern regarding the Company's business plan fuel forecast. The Dave Johnston contracts are **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** but the forecast that informed this contract negotiation was apparently **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

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[27] Staff/702, Anderson/6. (PacifiCorp's response to Staff DR 71).
[28] Staff/703. (PacifiCorp's response to Staff DR 71, Attachment 1).

forecast.[29,30] This is not forward-looking enough to consider potential changes to market conditions and new resource buildout during the contract's full length, and there is no indication that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** were considered in the Dave Johnston forecast.

**Q. What is your assessment of minimum take levels in the Hunter contract?**

A. The analysis for the Hunter generation forecast appears to be somewhat more robust, utilizing a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** with additional sensitivities to inform the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** new contracts.[31,32] In addition, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].**

**Q. What is your assessment of minimum take levels in the Craig contract?**

A. The new Craig coal contract is a five-year agreement, and once again PacifiCorp's negotiations appear to have been based on a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** forecast of generation.[33] Staff is also concerned that PacifiCorp agreed to a minimum take requirement at this plant at all, given that the Trapper mine is an "affiliate captive mine

[29] Staff/703. (PacifiCorp's response to Staff DR 71, Attachment 1).
[30] Staff/702, Anderson/9. (PacifiCorp's response to Sierra Club Data Request 1.13, part a).
[31] Staff/703. (PacifiCorp's response to Staff DR 71, Confidential Attachment 2).
[32] PAC/200, Ralston/7.
[33] Staff/703. (PacifiCorp's response to Staff DR 71, Confidential Attachment 1).

owned by three of the five Craig plant owners."[34] Staff requests the Company explain in Reply Testimony why it has agreed to be bound to a minimum take level at a mine where it is one of the owners, instead of agreeing to divide its share of costs over the tons of coal it actually needs in a given year.

**Q. Was generation at any of the plants with new coal contracts iteratively adjusted to meet a minimum take requirement in the 2022 TAM?**

A. No. Hunter, Craig, and Dave Johnston did not require iterative adjustments to meet minimum take requirements in the 2022 TAM, indicating that GRID dispatched them at or above 2022 minimum take levels based on economics. While this reassures Staff that the 2022 minimum take levels in these contracts were set somewhat appropriately for 2022, the minimum take levels could eventually become binding constraints.

**Q. What is Staff's recommendation regarding the new coal contracts?**

A. PacifiCorp has not demonstrated that the analysis informing its negotiations for these units was a robust attempt to identify the economic generation levels that would be optimal over the contract timeframe, **[BEGIN CONFIDENTIAL]** [redacted] [**END CONFIDENTIAL]**. Unless PacifiCorp can prove it has performed a robust analysis consistent with these expectations, Staff recommends the removal of the minimum take level assumptions for Dave Johnston and Craig as modeled in Oregon power cost filings moving forward.

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[34] PAC/200, Ralston/22.

It may be that, in a future TAM proceeding following development of a more rigorous methodology for forecasting economic levels of generation at its coal units, the improved methodology could be used to set minimum take levels for Craig and Dave Johnston. Staff would evaluate the merits of this approach in a future proceeding, but notes that it would help reduce risk for the Company while providing ratepayers with the benefit of a more reasonable estimate of minimum take levels that should have been reflected in the coal supply agreements from the outset.

Staff is continuing to look into the Hunter forecast. Since it appears to be more robust and appropriate, Staff does not recommend an adjustment or modeling change for Hunter at this time.

**Q. What is Staff's understanding of how the minimum take agreements can be removed for the purpose of power cost modeling in the future?**

A. Essentially, PacifiCorp should 1) refrain from adding a minimum take assumption to the modeling for applicable plants, and 2) model the applicable plants as having variable fuel costs equal to the price of coal, exactly as it would model them if it had negotiated the new coal contracts at the current price with no minimum take agreements.

**Q. Does this recommendation require a dollar adjustment in the 2022 TAM?**

A. No. Because Dave Johnston and Craig did not require an iterative adjustment to meet minimum take levels in the 2022 TAM,[35] no dollar adjustment is required.

## HUNTINGTON

**Q. Please provide background on the Huntington coal contract.**

A. The Huntington coal contract was initially brought to the Commission in Docket No. UM 1712, regarding the Deer Creek Mine closure. In its initial application, PacifiCorp requested the Commission find the Huntington contract to be prudent.[36] However the Commission declined to provide pre-approval, and made it clear that the contract was not included in its assessment of the benefits of the Deer Creek Mine closure:

> Accordingly, we take no action as to the reasonableness of the Huntington and Hunter plants' CSAs at this time, including the risks imposed by the take-or-pay provision. PacifiCorp may seek recovery of the fuel costs associated with the CSAs in future power cost proceedings.[37]

In the 2016 TAM, PacifiCorp mentioned the Huntington contract in Opening Testimony,[38] however the contract does not appear to have been discussed any further in that proceeding.

**Q. What are Staff's concerns regarding the Huntington contract?**

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[35] Staff/702, Anderson/5. (PacifiCorp's response to Staff DR 66).
[36] PacifiCorp's Application for Approval of the Deer Creek Mine Transaction in Docket No. UM 1712.
[37] *In re PacifiCorp*, OPUC Docket No. UM 1712, Order No. 15-161 (May 27, 2015).
[38] UE 296 - PAC/300, Larsen/4.

A. The implications of failing to sufficiently assess generation levels are much more troubling with respect to the Huntington contract than to the new contracts, which are shorter in duration. The Huntington contract began approximately five years ago and will not expire until **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]** This makes the Huntington contract PacifiCorp's **[BEGIN CONFIDENTIAL]** [redacted][39,40] **[END CONFIDENTIAL]** Staff is concerned that this contract may have been informed by a short-sighted generation forecast, in the same way that the new contracts appear to have been. However, PacifiCorp's responses to Staff discovery on this matter show that the Company has not retained any of the workpapers for analysis performed before negotiating the Huntington contract.[41]

PacifiCorp bears the burden of proving that its Huntington contract minimum take levels were decided prudently, based on what PacifiCorp knew or should have known at the time the contract was executed. Until PacifiCorp can demonstrate that the minimum take was set prudently, Huntington minimum take levels should not be included in power cost modeling.

**Q. What would have been included in a robust consideration of economic generation levels at Huntington?**

A. In Staff's opinion, a robust analysis of economic generation levels at Huntington would have included a long-term generation forecast that

[39] Staff/703. (PacifiCorp's confidential response to Sierra Club DR 1.12).
[40] Staff/702, Anderson/14. (Sierra Club DR 1.12).
[41] Staff/702, Anderson/10. (PacifiCorp's response to Staff DR 154).

considered the long-term resource buildout in the Company's most recent Integrated Resource Plan. The forecast would have been designed for the purpose of determining the most economic generation levels at Huntington over the entire duration of the contract, and it would not have assumed any minimum take levels for Huntington after the expiration of its current contract. It would have considered the possibility of economic cycling or early retirement.

**Q. Please explain how the minimum take level at Huntington is currently harming customers.**

A. The Huntington plant already requires iterative adjustments in the 2022 TAM because GRID would not choose to dispatch the plant to its minimum take levels otherwise.[42] This is true in the as-filed case with "must run" requirements turned off **[BEGIN CONFIDENTIAL]** [redacted].[43] **[END CONFIDENTIAL]** Already, about five years after the contract was signed, PacifiCorp has to manually increase the dispatch level at Huntington so that the minimum take quantity of coal can be utilized. This indicates to Staff that the minimum take levels in the Huntington contract were not calibrated appropriately for the economic realities even a few years into the future.

**Q. What does Staff recommend regarding the Huntington plant in Oregon power cost dockets?**

[42] Staff/702, Anderson/5. (PacifiCorp's response to Staff DR 66).
[43] Staff/703. (PacifiCorp's response to Staff DR 163, attachment).

A. PacifiCorp has not demonstrated that its generation forecast used to select minimum take levels in its Huntington coal contract was well-suited for that purpose. For this reason, ratepayers should not bear the entire cost of the uneconomic dispatch at Huntington for the duration of the Huntington contract. Staff recommends removing the minimum take requirement at Huntington in future TAM proceedings for purposes of forecasting NPC unless the Company can prove that its analysis used to negotiate minimum take levels was prudent.

Alternatively, if the Company develops a robust forecasting methodology for future minimum take provisions in coal supply agreements, then it may be appropriate to use the forecasting methodology to set a new, prudently determined minimum take level at Huntington for TAM modeling purposes.

For the 2022 TAM, Staff recommends an adjustment that represents the value lost by customers who pay for excess coal generation at Huntington instead of purchasing power at market prices or using lower cost generation. This would be calculated as the quantity generated at Huntington in GRID before iterative adjustments ($Q_1$), minus the quantity after iterative adjustments ($Q_2$), times the difference between the average Low Load Hour (LLH) market price at Mid-C and Palo Verde during the off-peak season in the 2022 TAM ($P_1$) and the cost of coal at Huntington ($P_2$), or, $(Q_1 – Q_2) * (P_1 – P_2)$. This downward adjustment should approximate the value lost to customers due to the minimum take agreement at Huntington. Staff's preliminary calculation results in a dollar adjustment of **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] **[END CONFIDENTIAL]** on an Oregon-allocated basis. [44, 45, 46]

Alternatively, PacifiCorp could re-run the GRID model without minimum take assumptions at Huntington and the results could be used to make an adjustment.

**Q. Is it reasonable for the Commission to require a change to the modeling of the Huntington contract now, several years after it was signed and included in rates?**

A. Yes. At the time that the Company executed the Huntington coal supply agreement, it was aware of concerns about minimum take provisions in coal contracts and the impact on economics for the Company's coal generating units in the long-term.[47] Nevertheless, the Company executed the agreement. The Commission's prudence standard judges prudence based on what the Company knew or should have known at the time the decision was made.[48] While the Commission may have approved power costs with the full minimum take level at Huntington in the past, in this year's TAM it has become clear that there is little reason for confidence in the analysis used to support the minimum take level in the Huntington coal contract. The Company has been unwilling or unable to provide supporting evidence otherwise.

[44] Staff/702, Anderson/12. (PacifiCorp's response to Staff DR 162 provided $Q_1$ and $Q_2$).
[45] See PacifiCorp's 2020 FERC Form 1 for Huntington cost per MWh, accessed at https://apps.puc.state.or.us/edockets/docket.asp?DocketID=17653.
[46] This calculation used PAC's Average 2022 market prices at Palo Verde and Mid C during off-peak months as forecast in the 2022 TAM.
[47] Order No. 15-161 at 10-12.
[48] Order No 12-493 at 25-27.

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

A. Yes.

CASE: UE 390
WITNESS: ROSE ANDERSON

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 701

# Witness Qualifications Statement

**June 9, 2021**

**WITNESS QUALIFICATION STATEMENT**

| | |
|---|---|
| NAME: | Rose Anderson |
| EMPLOYER: | Public Utility Commission of Oregon |
| TITLE: | Senior Economist<br>Energy Resources and Planning Division |
| ADDRESS: | 201 High Street SE. Suite 100<br>Salem, OR. 97301 |
| EDUCATION: | Master of Science, Agriculture and Resource Economics, University of California Davis, Davis, CA<br><br>Bachelor of Arts, International Political Economy<br>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 planning dockets and rate cases. I have participated in OPUC rate cases including UE 374, 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 OPUC I was a Research Associate at McCullough Research for two years. My responsibilities included economic analysis of energy markets and generators. |

CASE: UE 390
WITNESS: ROSE ANDERSON

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

## STAFF EXHIBIT 702

## Exhibits in Support
## Of Opening Testimony

## June 9, 2021

**OPUC Data Request 61**

Please refer to PAC/100, Webb/14. Regarding the statement "Since emergency purchases are not actual transactions available to the Company, the modeling result reflected a solution that did not reflect actual operations and could not reliably serve load", please explain the difference between emergency purchases and other system balancing purchases.

**Response to OPUC Data Request 61**

Emergency Purchases, in the Generation and Regulation Initiative Decision Tool (GRID), are the result of modeling resource shortages and occur when resources in an area of the Company's system are fully dispatched, and / or transmission into the area is insufficient to meet the load in that area.

Balancing Purchases, in GRID, are model driven forecasted market interactions that are not associated with any specific counterparties. Balancing purchases are calculated based on the system balancing energy and hourly prices.

**OPUC Data Request 165**

**Coal Cycling**
The Economic Coal Cycling Study identified reliability issues when GRID is allowed to economically cycle all of the company's coal units. Does PacifiCorp expect that it will be possible for the Aurora model to identify economic cycling opportunities that do not cause reliability issues? For example, is Aurora able to make dispatch and cycling choices while still being required to meet requirements for reserves and reliability?

**Response to OPUC Data Request 165**

Referencing Confidential Exhibit PAC/107 (Economic Coal Cycling Study), the Company responds as follows:

Please refer to the direct testimony of Company witness, David G. Webb, specifically page 16, line 17 through 20 which states "GRID models more economic cycling than can occur in actual operations. Allowing GRID to increase economic cycling exacerbates the inherent differences between system optimization modeled in GRID and system optimization that can be realized in actual operations."

AURORA is expected to identify economic cycling opportunities. Since dispatch decisions are performed daily, AURORA should be able to meet reliability and ancillary services requirements. However, as with the Generation and Regulation Initiative Decision Tool (GRID), due to perfect foresight, the decisions taken by AURORA may similarly exacerbate the differences between model output and what can be realized in actual operations.

**Sierra Club Data Request 1.5**

With respect to the dispatch and costing tiers of the Company's coal units in NPC:

(a) Please explain the use of different dispatch or costing price tiers in GRID and what each represents.

(b) Please explain and provide a numeric example for how the dispatch and costing tiers are related to the total unit price of coal for a fixed price or take-or-pay fuel contract.

(c) Please explain and provide a numeric example for how the dispatch and costing tiers are related to the total unit price of coal for a fuel contract with liquidated damages (i.e., damages less than the total cost of fuel).

(d) Please explain and provide a numeric example for how the dispatch tier and costing tiers are related to the total unit price of coal for a fuel contract with no fixed terms or liquidated damages.

(e) For each of the company's coal units, please provide the calculations used to derive the dispatch and costing tier. Please provide all associated work papers used to calculate the two tiers.

**Response to Sierra Club Data Request 1.5**

(a) Please refer to the Company's response to Sierra Club Data Request 1.2, subpart (l).

(b) The take-or-pay provisions in PacifiCorp's coal supply agreements (CSA) require the payment for the coal even if it is not delivered or used for generation, therefore the fuel portion of the marginal cost of generation in that price tier is zero. The Company does not use the average price as a dispatch price in short-term forecasts because the cost of coal in a take-or-pay volume tier is not avoidable.

For example, suppose a CSA had a provision with a minimum take-or-pay volume of 1 million tons. The incremental price for volumes between zero and 1 million tons would be zero because the take-or-pay volumes are treated as a previously incurred cost. Suppose further that the CSA set a price for the first 1 million tons at $2 per million British thermal units ($/MMBtu), and any purchases above 1 million tons were $1/MMBtu. The incremental price above the take-or-pay volume of 1 million tons would be $1/MMBtu. Assuming that the Company purchased 2 million tons, the average or "costing tier" price in the Generation and Regulation Initiative Decision Tool (GRID) would be

$1.50/MMBtu, and the incremental or "dispatch tier" price would be $1/MMBtu.

(c) Liquidated damages provisions provide for a payment, less than the full price of coal, to be due if PacifiCorp fails to take the minimum contract volume. The Company accounts for liquidated damages in its dispatch analysis by recognizing that these costs will be incurred if the units are not dispatched at a level that consumes coal above the contractual minimums.

For example, suppose the same CSA example in the Company's response to subpart (b) above had a liquidated damages provision in conjunction with the minimum volume of 1 million tons. Therefore, instead of the Company having a full take-or-pay provision and being obligated to pay $2/MMBtu for any shortfall of volumes below 1 million tons, the liquidated damages provision called for a payment of $0.25/MMBtu for any shortfall. Therefore, the "dispatch tier" price would be $1.75/MMBtu for volumes between zero tons and 1 million tons. The "dispatch tier" for volumes over 1 million tons would be $1.00/MMBtu. If the Company purchased 2 million tons, the "costing tier" price would remain at $1.50/MMBtu.

(d) Leaving aside the complexities that accompany multiple tiers, in an instance where there is a single tier with no minimum take and no maximum, the costing tier and dispatch tier would be identical.

(e) The "dispatch tiers" used in GRID for purposes of the 2022 transition adjustment mechanism (TAM) are determined via an iterative process to arrive at a fuel consumption number that satisfies the minimum purchase obligations of contracts with such provisions. As such, there is no closed form calculation and no work papers to provide. Please refer to the confidential work papers supporting the direct testimony of Company Witness, Dana M. Ralston for details on the calculation of costing tier prices.

**OPUC Data Request 66**

Please refer to PAC/100, Webb/30. Regarding the statement "iterative GRID runs may be necessary to ensure that coal burn volumes are consistent with minimum take requirements across the coal fleet":

(a) Please identify the number of iterative runs underlying the filed coal fuel burn expense of $543.4 million found in PAC/102, Webb/5and identify the work papers where the iterations can be found.

(b) Please provide a narrative explanation of how removal of the "must run" setting has affected the iterative process.

(c) Please identify any coal units which cleared their respective minimum purchase obligations without iterative adjustment of the incremental coal price input.

**Response to OPUC Data Request 66**

(a) The iterative runs are not processed into reports that can be provided since the net power costs (NPC) are both preliminary and incomplete (only the annual fuel consumption totals are evaluated). Typically, there are somewhere between five and 20 iterative runs, given that the goal is to achieve a forecasted fuel consumption very close to the minimum purchase obligation at several plants, and that there is a certain amount of switching between units that has to be accounted for when adjusting the prices.

(b) The effect is no different than the effect of any other change to a constraint. The process itself and the goal of that process both remain the same.

(c) In the initial filing of the 2022 transition adjustment mechanism (TAM), the coal units requiring adjustment to meet the minimum take obligation are Colstrip, Hayden, and Huntington. The Craig, Dave Johnston, Hunter, Jim Bridger, Naughton, and Wyodak coal units required no adjustment.

**OPUC Data Request 71**

Please refer to PAC/200, Ralston/5. Regarding the statement "The negotiations for the new agreements were based upon a generation forecast that was part of the overall fueling budget for the Company":

(a) Please provide a narrative explanation of how the overall fueling budget is developed and its relationship to the annual TAM filing.

(b) Please provide a copy of the 2022 overall fueling budget or reference where it can be found in the TAM work papers.

**Response to OPUC Data Request 71**

(a) PacifiCorp's finance department calculates net power costs (NPC) over the 10-year business planning horizon based on projected data using the Generation and Regulation Initiative Decision Tool (GRID). The overall fueling budget is developed by obtaining the thermal availability including planned maintenance, variable operation and maintenance (O&M) unit costs, minimum load levels and heat rate input/output curves from thermal plant management. Incremental fuel costs and minimum take constraints are obtained, including volumes available at those incremental prices. PacifiCorp loads the data into GRID and runs the model using these inputs. These results are reviewed for reasonableness by comparing them to expected targets based on historical coal generation volumes adjusted for forecasted changes in load, anticipated system resources, renewables, and plant retirements.

The business planning generation forecast is run for a different purpose and at a different time of year than GRID runs for ratemaking purposes such as the transition adjustment mechanism (TAM). The purpose of the business plan GRID run is to try to capture recent market trends and volatility that could impact the forecast year whereas the ratemaking GRID runs try to capture more normalized results. The costs associated with the new coal supply agreements (CSA) that were negotiated and signed using the reviewed GRID results are included in the TAM.

(b) Please refer to Confidential Attachment OPUC 71-1 and Confidential Attachment OPUC 71-2, which provide the generation forecast that was used when negotiating and signing the new agreements. This includes the PacifiCorp's overall fueling budget that was relied upon for those new agreements.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

**OPUC Data Request 157**

**Coal Supply Agreements**
In PacifiCorp's response to Staff DR 72, the Company explained that the GRID model results that inform its coal contract decisions are,

> "reviewed for reasonableness by comparing them to expected targets based on historical coal generation volumes adjusted for forecasted changes in load, anticipated system resources, renewables, and plant retirements".

Please provide more detail on this review process, including the PacifiCorp teams that reviewed the GRID results, and the number of years into the future for which the reviewers determined the model results to be reasonable.

**Response to OPUC Data Request 157**

PacifiCorp objects to this request as outside the scope of this proceeding, overly broad, cumulative, and not reasonably calculated to lead to admissible evidence. Without waiving the foregoing objection, PacifiCorp responds as follows:

The finance, fuel supply and energy supply management (ESM) groups review 10-year business plan coal generation forecasts for all 10 years of the 10-year business plan horizon.

The coal generation levels are reviewed compared to prior budget and compared to historical actuals. The review is performed at both the total coal generation level and at the individual resource level.

Individual coal plant forecasts are also reviewed for reasonableness considering the coal supply agreement (CSA) minimum take levels, maximum take levels and price change tier levels as well as in comparison to their historical generation and prior budgeted generation.

**Sierra Club Data Request 1.13**

Please identify and provide any new coal supply agreements that have been executed since the last TAM proceeding (UE 375).

(a) For any identified coal supply agreements that have been executed since the last TAM proceeding (UE 375), please identify and provide the business planning forecasts for coal consumption that were used in negotiating these contracts.

**Response to Sierra Club Data Request 1.13**

As discussed in the direct testimony of Dana M. Ralston, PAC/200, page 2, line 19, there are five new coal supply agreements (CSA) that have been executed since the 2021 Transition Adjustment Mechanism (TAM), docket UE 375:

- Dave Johnston Plant – Peabody North Antelope Rochelle and Peabody Caballo (Please refer to the direct testimony of Mr. Ralston, PAC/200, page 3, lines 5 through 7)

- Hunter Plant - Wolverine and Bronco (Please refer to the direct testimony of Mr. Ralston, PAC/200, page 7, lines 3 through 5)

- Craig – Trapper (Please refer to the direct testimony of Mr. Ralston, PAC/200, page 9, lines 9 through 11)

(a) Please refer to the Company's response to OPUC Data Request 71, specifically Confidential Attachment OPUC 71-1, which was the business planning forecast developed December 9, 2020 and used for the Dave Johnston and Craig final contract negotiations.

For the Hunter plant contracts, please refer to Confidential Attachment OPUC 71-2 for the generation forecast modeling, which was completed on June 22, 2020, and that modeling assessed expected output over scenarios that spanned a range of potential future conditions. A review of the status of key inputs relative to the June 22, 2020 scenarios was completed on December 10, 2020.

**OPUC Data Request 154**

**Coal Supply Agreements**
In Pac's response to Staff DR 72, the Company explained that the GRID model is used to inform negotiations on its coal contracts.

(a) Please provide work papers, model inputs, and model outputs for the GRID model run(s) that the Company used to inform its most recently signed Huntington coal contract.

(b) Please provide work papers, model inputs, and model outputs for the GRID model run(s) used to inform the Dave Johnston, Hunter, and Craig coal contracts introduced in this TAM filing.

Please provide the work papers, inputs, and outputs in electronic, Excel format with formulae and references intact.

**Response to OPUC Data Request 154**

PacifiCorp objects to this request as outside the scope of this proceeding, overly broad, cumulative, and not reasonably calculated to lead to admissible evidence. Without waiving the foregoing objection, PacifiCorp responds as follows:

(a) The Company no longer has the work papers, model inputs, or model outputs for the Generation and Regulation Initiative Decision Tool (GRID) run performed in 2014 for the 10-year business plan year starting January 1, 2015. General department budgeting materials have a six-year retention. The prudence of the transaction was reviewed by the Public Utility Commission of Oregon (OPUC) along with the benefits to customers in executing the Huntington coal supply agreement (CSA) in Docket UM 1712. Greater detail on the economics of this transaction was provided in that proceeding. For ease of reference, please refer to Confidential Attachment OPUC 154-1, which provides a copy of PacifiCorp's application in Docket UM 1712.

(b) The CSAs for Dave Johnston and Craig relied upon forecasts generated in the 10-year business plan finalized in 2020, and a GRID update ran in December 2020. The update ran in December 2020 updated the variable operations and maintenance (O&M) costs at the Jim Bridger facility, updated price curves and updated transmission topology in the Wyoming area. Please refer to Confidential Attachment OPUC 154-2, which provides work papers, model inputs, and model outputs for the relevant GRID run. For the Hunter CSA, please refer to Confidential Attachment OPUC 154-3, which provides the work papers, model inputs, and model outputs for the relevant GRID run.

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**OPUC Data Request 162**

**Coal Supply Agreements**
Please provide the monthly generation levels at each coal unit in the 2022 TAM (with "must run" constraints turned off):

(a) Before iteratively adjusting the model to meet minimum take requirements, and

(b) After the iterative adjustments for minimum take.

**Response to OPUC Data Request 162**

(a) Please refer to Confidential Attachment OPUC 162.

(b) Please refer to Confidential Attachment OPUC 162.

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**OPUC Data Request 163**

**Coal Supply Agreements**
See Pac/100, Web/17. Please provide the monthly generation levels at each coal unit in the "counterfactual" study with "must run" constraints turned on:

(a) Before iteratively adjusting the model to meet minimum take requirements, and

(b) After the iterative adjustments for minimum take.

**Response to OPUC Data Request 163**

The Company assumes the reference to "Web" is intended to be a reference to Company witness, David G Webb. Based on the foregoing assumption, the Company responds as follows:

(a) Please refer to Confidential Attachment OPUC 163.

(b) Please refer to Confidential Attachment OPUC 163.

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**Sierra Club Data Request 1.12**

For each coal contract (including affiliated mines) held and in force by the Company:

(a) Identify the mine or supplier of the coal.

(b) Identify the plant(s) to which the coal is delivered.

(c) Identify if the contract is take-or-pay, liquidated damages, or fully variable. If the contract takes another form that is functionally different than take-or-pay, liquidated damages, or variable cost, specify the form of the contract and provide a note describing the contractual obligation.

(d) Specify the minimum tonnage requirement, or any tier volume constraints.

(e) Specify the coal price in $/ton, including any tiers or other pricing structure.

(f) Specify the coal heat content.

(g) Identify the state and end date of each contract.

**Response to Sierra Club Data Request 1.12**

(a) Please refer to Confidential Attachment SC 1.12 which provides a summary table providing coal supply agreements (CSA) and transportation contracts listing supplier or transporter, plant, contract type (take-or-pay, liquidated damages, etc.), state, term end, and minimum tonnage requirement.

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

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

(d) Please refer to the Company’s response to subpart (a) above.

(e) Please refer to the Company’s response to Sierra Club Data Request 1.8.

(f) Please refer to the Company’s response to Sierra Club Data Request 1.8.

(g) Please refer to the Company’s response to subpart (a) above.

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# Confidential Staff Exhibit 703

**Consisting of electronic files:**

**Attach SC 1.12, Attach 1, CONFIDENTIAL**

**OPUC 71-1 CONF Attach**

**OPUC 71-2 CONF Attach**

**OPUC 162 CONF Attach**

**OPUC 163 CONF Attach**

**SL02 ORTAM22_xCoal Cycling CONF**

## Is

## Filed in electronic format

CASE: UE 390
WITNESSES: CURTIS DLOUHY

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

## STAFF EXHIBIT 800
## EIM Model and Market Caps
## REDACTED

## Opening Testimony

## June 9, 2021

**Q. Please each state your name and occupation.**

A. My name is Curtis Dlouhy. I am a Senior Economist within the Energy Rates, Finance and Audit (ERFA) Division of the Public Utility Commission of Oregon (Commission or OPUC).

**Q. What is your common business address?**

A. 201 High Street SE, Suite 100, Salem, OR 97301.

**Q. Describe your educational background and work experience.**

A. My educational background and work experience are set forth in my Witness Qualification Statement, provided as Exhibit Staff/801.

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

A. I am responsible for the analysis of two separate inputs into PacifiCorp's (PAC or Company) GRID model in Docket No. UE 390:

1. Energy Imbalance Market (EIM) Benefits Model; and
2. Market Capacity Limits.

**Q. Have you issued data requests (DRs) in this rate case?**

A. Yes. I issued Data Requests 13-18 as part of my investigation into the two issues outlined above.

**Q. How is your testimony organized?**

A. I organize my testimony as follows:



**Q. Did you prepare exhibits in support of your opening testimony?**

A. Yes. I prepared the following exhibits:

Staff/801 ..................................................................... Witness Qualifications
Staff/802 ........................... Data Responses in Support of Opening Testimony
Staff/803 ........................................ Exhibits in Support of Opening Testimony
Staff/804 .................................. Attachment in Support of Opening Testimony

**Q. Can you summarize your overall recommendations on these two issues?**

A. Yes. I recommend making some changes to the Company's method of forecasting EIM benefits and rejecting the Company's proposal to adjust the way it calculates market caps in GRID. These two changes result in a decrease of company-wide forecasted EIM benefits of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** and an increase of forecasted off-system sales of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, respectively. On an Oregon-allocated basis, these adjustments result in an increase to NPC of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** with regards to EIM benefits and a decrease to NPC of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for market caps.

**ISSUE 1 – EIM ENERGY TRANSFER BENEFITS REGRESSION MODEL**

**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 deals with the regression model used to forecast energy transfer benefits.[1]

**Q. Please provide an overview of your testimony.**

A. In this section of testimony, I will answer the following questions:

- What are EIM energy transfer benefits and how are they calculated?
- What are the four regressions used by the Company to forecast future EIM energy transfer benefits, and how are they used to forecast a final transfer benefit amount?
- What should an econometrician keep in mind when setting up regressions, particularly in the context of energy transfer benefits?
- Do I recommend any changes to the Company's model, and if so, how do the changes affect the Company's NPC?

I recommend adjustments to one of the Company's regressions used to model export benefits from to better reflect econometric norms. This results in an adjustment of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** to the Company system wide, or **[BEGIN**

[1] See Staff/100, Issue 2 for discussion of GHG benefits and flex reserve benefits.

**CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** on an Oregon-allocated basis.

**Q. What is the Company's projected energy transfer benefit for the 2022 TAM?**

A. The Company's system-wide EIM transfer benefits are **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** out of the Company's **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** total EIM benefits, which also include GHG benefits and flex reserve. EIM and GHG benefits included in the 2022 TAM are **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, which is an increase of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** over the 2021 TAM.

**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.

CAISO's method to determine energy transfer benefits to the utility is calculated by subtracting the cost paid for energy and transmission from the counterfactual cost of the utility generating the same amount of energy on its own. CAISO claims that it has saved its members over one billion dollars collectively since forming in late 2014.[2]

While the broad intuition remains the same, it should be noted that the Company and CAISO differ in the particulars of how to calculate historic EIM benefits. Rather than constructing a counterfactual study, the Company compares actual costs incurred to actual compensation for energy.

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

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

**Q. Does Staff have any concerns with PacifiCorp's methodology for calculating historic EIM benefits, which is used to inform forecast energy transfer benefits?**

A. No. As detailed in Staff/100, Staff is satisfied with the Company's current method for calculating historic EIM benefits. However, I do have concerns with the way historic EIM benefits are used to model forecast EIM benefits through the market fundamentals model.

**Q. Please describe the market fundamentals model that the Company uses to calculate EIM transfer benefits in the 2022 TAM.**

A. PacifiCorp's market fundamentals model is based on four separate regressions estimated using Ordinary Least Squares (OLS) whose results are

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[2] See https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx.

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
- PACW Imports

The regressions are estimated using monthly data on historic energy transfer benefits and market characteristics from January 2015 through January 2021, with the exception of the PACE Import model whose data begin in December 2015.

**Q. Please explain the flow of the model and how it is used to forecast energy transfer benefits.**

A. The general flow of the model can be summarized as follows:

1. For each of the four regions above, a regression is estimated to predict average daily energy transfer benefits for each month.
2. The regression and expected future prices are used to forecast the average daily transfer benefits for each month and model.
3. The results of the forecasts are multiplied by the number of days in each month.
4. All the forecasted values are added together to produce a final energy transfer benefits forecast.

**Q. What are regressions and OLS, and how are they normally utilized?**

A. A regression is a linear representation of the relationship between one or more independent variables (e.g. drivers of the forecast) and a dependent variable (e.g. the energy transfer benefit). Ordinary least square (OLS) is the most widely used way to statistically estimate a regression. OLS relies on six assumptions to work correctly, but there are countless methods to fix violations of these six assumptions. I will highlight the assumptions and fixes that are relevant to this testimony.

**Q. Does the Company use the same regression to forecast EIM benefits for each separate region described above?**

A. No. The regressions for all four scenarios are set up differently.

**Q. Do you believe that all four regressions should be set up in the same way?**

A. In theory, the four regressions are modeling the same process and should be responding in similar manners. In practice, some price signals that are important to one market are not relevant to another market. It is therefore up to the modeler to find the optimal set of regressors to forecast future EIM benefits.

**Q. How should a modeler determine the optimal set of regressors to be used in a regression used to forecast?**

A. There is general sequence of steps that a modeler should keep in mind when setting up a regression to forecast:

1. Find a set of variables that seem like they should affect the dependent variable of the regression.
2. Perform inquiry into whether it whether each variable actually matters in the model. Exclude the variables that don't matter in order to create the most efficient model.
3. Properly transform the variables so that the relationship between the model inputs and the model output is linear. This step will be addressed later in testimony.

These should not be interpreted as firm rules, but rather a broad summary when setting up a regression on sparse data. As data sets become larger, efficient modelling becomes less of a concern.

**Q. How big are the data sets used to forecast EIM benefits?**

A. Each of the four data set contains no more than 73 data points, which are sufficiently small enough that finding efficient models is an important concern.

**Q. How do you determine which model performs better for forecasting purposes?**

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 mode. For the purposes of this testimony, I've chosen to focus on the Adjusted R-Squared for a few reasons:

- Backcasting requires the modeler to throw out data and see how the model performs in predicting past values. As I've previously stated, each of these models only has at most 73 monthly data points and I have concerns about omitting data with so few observations.
- R-Squared measures how well a model fits and will necessarily rise as the number of inputs rises. 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.
- Adjusted R-Squared is similar to R-Squared in that it measures model fit, but it penalizes a model that has a lot of useless parameters. This makes it easier to compare models with different number of parameters while still being intuitive like R-squared.

**Q. Does the Company provide the code used to estimate EIM benefits?**

A. Yes. As requested by Staff Data Request 13, the Company provided the code it uses to forecast EIM benefits using the coding language R.[3] The results of this estimation are then put into the Company's GRID model.

[3] Staff/802, Dlouhy/1.

**Q. Do you believe that there is reason to further probe into PacifiCorp's EIM Benefit Model?**

A. Yes. I found two things that initially caused concern in PacifiCorp's EIM benefit model:

1. Inconsistencies in the modelling technique used in the two import models and the two export models.
2. Potential estimation problems introduced into the model by the modelling choice for the error term.

**Q. What inconsistencies do you see in the Company's EIM Benefits Model?**

A. I became suspicious of the Company's data transformation choices in its four separate EIM benefits models. Particularly, I noted that the Company transformed its variables using natural logs and exponentiation in its import regressions while relying on polynomial transformations in its two export regressions. Given that these four models are essentially modeling the same process, I found the decision to use two very distinct sets of transformations concerning.

**Q. Why is it necessary to transform the variables in the first place?**

A. OLS can only be used to estimate models that are linear in parameters, but oftentimes variables are not related linearly. For example, traffic congestion does not get worse linearly with each car that enters a highway. Instead, suppose traffic still flows very well with few cars but gets *exponentially* worse with each car added, meaning that the first car in traffic affects traffic much differently than the thousandth car. This is not a linear relationship.

This means that using OLS to estimate the effects of cars on traffic congestion will not work properly. Thankfully, OLS functions correctly if the data can be transformed so that the relationship between variables is indeed linear. In the case of the cars on traffic, a model estimating the effect of the number of cars on the natural log of traffic congestion will work perfectly fine if the true relationship between the raw variables is indeed exponential.

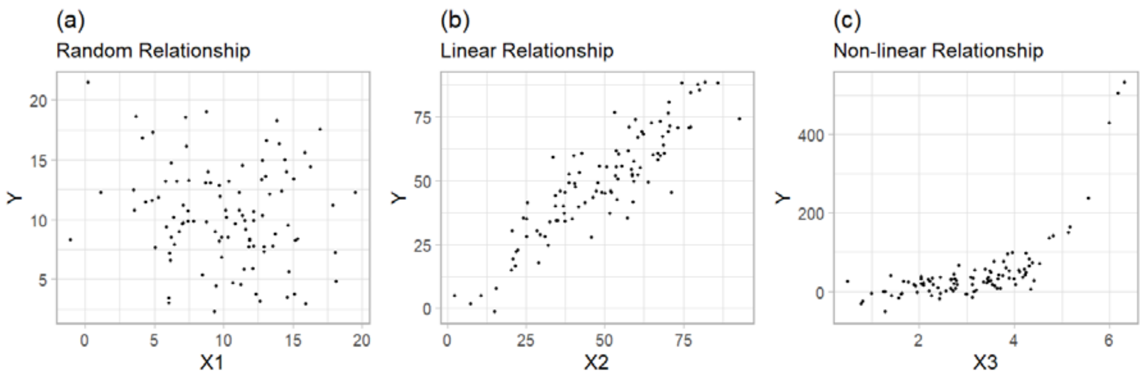
**Q. Can you demonstrate the difference between variables with no relationship, a linear relationship, and a non-linear relationship?**

A. Yes. In Figure 1, I recreate the three scenarios above by simulating data. In Panel (a), I model two variables that do not appear related. You can see clearly that the relationship between $X_1$ and Y appears to be random. This means that the two variables are not related and $X_1$ should not be used to model Y.

In Panel (b), I model two variables that are linearly related. While it does not appear that $X_2$ can *perfectly* predict Y, we can clearly see that a line can be cleanly drawn to approximate the relationship. Therefore, $X_2$ should be included in a regression used to predict Y in its current form.

In Panel (c), I model two variables that are non-linearly related. Like the relationship in Panel (b), it looks like a curve can be drawn to represent the relationship between $X_3$ and Y, meaning that $X_3$ has power in predicting Y. However, OLS requires all relationships to be linear, so $X_3$ must be transformed before it is put into a regression.

***Figure 1: Random, Linear and Non-Linear Relationships***




**Q. How does a modeler know how to properly transform a variable?**

A. A quick and easy way to check if a variable should be transformed is to plot the variables' relationships to each other. If it appears that the variables form a line, then no transformation is needed. If instead the relationship does not form a line, then the variable should be transformed in some way. While it is up to the modeler to choose the correct transformation, there are some rules of thumb that econometricians generally follow when transforming variables.

**Q. What rules of thumb should be followed when transforming variables and preparing a model?**

A. In econometrics, log transformations are generally the preferred way to handle relationships that appear exponential. While there are other ways to handle these, log transformations have a couple desirable properties:

- If the error terms of the underlying raw data have a lognormal distribution, then the log-transformed data will have a normal distribution, which is another necessary assumption for OLS.

- Log transformations in theory will allow a variable to range from negative infinity to positive infinity, whereas other similar ones, such as the square root transformation, do not.
- Log transformations have clean elasticity interpretations if needed.

When setting up a model, the econometrician should be sure to include only variables and transformations of variables that are relevant to the model. Inclusion of irrelevant variables can mitigate the predictive power of the model. This is a particularly salient problem when models have few observations, like each of the regressions in the Company's energy transfer benefits model.

**Q. What is an error term?**

A. Simply put, an error term is just the difference between what a model forecasts and what actually happens. Because perfect foresight does not exist, all models will have some forecasting error, called the error term and often denoted by $\varepsilon$. This is not necessarily a bad thing, and without getting into specifics, OLS actually *uses* this error term to form its best statistical approximation of the regression. A key assumption of OLS is that all errors are independent from each other, and OLS can produce inaccurate estimates if this assumption does not hold.

**Q. How can error terms introduce estimation problems and what problems are relevant to the Company's energy transfer benefits model?**

A. While this assumption may seem innocuous, it is worth pointing out that a number of real-life scenarios can violate this. At issue in this testimony, errors can often be *serially correlated.* In laypersons' terms, errors exhibit serial autocorrelation if a forecasting error in one time period is related to the forecasting error in the ensuing time period. See Exhibit 804 for a more detailed description of serial correlation.[4]

**Q. How can these problems with the error term be addressed?**

A. Serial correlation is nothing new to time-series econometrics, and methods exist to identify and address it. It can be identified by using the Durbin-Watson statistic, and two commonly used methods to correct for serial autocorrelation, the Praiss-Winsten method and the Cochrane-Orcutt method, have pre-built programs in many statistical packages. PacifiCorp uses the Durbin-Watson statistic to show that serial autocorrelation exists in its regressions and corrects for it using the Cochrane-Orcutt method. See Exhibit 804 for a description of both methods and how to implement them in Stata, a common statistical coding language.[5]

**Q. What are the four regressions used by the Company to forecast EIM benefits?**

A. The four regressions that the Company estimates are:

**[BEGIN CONFIDENTIAL]**

[redacted]

[4] Staff/804, Dlouhy/2-13.
[5] Staff/804, Dlouhy/16, 31.

[redacted] $g$ [redacted] $g$ [redacted]

**[END CONFIDENTIAL]**

I would like to reiterate that all variables are measured at the monthly level.

All four regressions are estimated in R.

**Q. What do each of the variables signify?**

A. Each of the variables are defined as the following:

**[BEGIN CONFIDENTIAL]**

[redacted]

[redacted]

**[END CONFIDENTIAL]**

**Q. What were your main concerns when conducting analysis on the EIM benefits models?**

A. My largest concern was that the four regressions were all set up differently. In conducting analysis, I individually scrutinized each variable to determine its relevance to each regression and the method by which the variables are transformed.

I would like to note that econometrically speaking, there is no harm in including an irrelevant variable in a regression on a large data set, but doing so in a regression over smaller data sets such as these will substantially lower the predictive power. For this reason, my recommended models will leave out variables that are not relevant. The models currently used by the Company follow this convention as well.

**Q. Are there any areas where you believed the Company correctly set up its regression models?**

A. Yes. I am satisfied with the model specification for the PACE and PACW Import models in their current form. I conducted the following analysis to confirm the right modeling choices were made across all four regressions and made the following conclusion:

- Checked the relationship between the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** and all four regressions. I found that the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** only mattered in the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.
- Checked that there was indeed serial autocorrelation in the error term that needed to be addressed in the models and that the Company properly addressed it. I found that PacifiCorp's use of the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** to eliminate the serial autocorrelation is effective and led to nearly identical results to the similar Prais-Winsten technique.
- Checked the predictive power of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. If $ln(Gas\ Prices)$ is put into the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** model, its coefficient estimate is not statistically significant at the 10 percent level, which is generally thought of as the minimum standard to call a variable "statistically significant." A scatterplot of the relationship between **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** confirms that it does not belong in either Import model.
- Despite the unorthodox transformations in **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, I found that the

Company's model fit the data dramatically better than the more traditional econometric technique of transforming data using logs. Although some inadvisable transformations could be used to generate a model with approximately the same fit as the Company's current regression, I could not find an alternate regression that bettered the Company's while still utilizing common combinations of data transformations. I includes the regression fit tables and a plot demonstrating the predicted values of both the Company's model and my alternate model using log transformations in Confidential Exhibit 803 to highlight this.[6] Note that the R-Square and Adjusted R-Square are much higher in the Company's current model and that the Company's current model matches historical data much more closely.

**Q. Do you identify any problems with any of the four regressions listed above?**

A. Yes. As noted, the preferred econometric way to address data relationships that appear exponential is to transform variables using logs for reasons described above. While it is not unheard of to use squared values as regressors, I have never encountered a regression in an academic journal where both the independent and dependent variables are raised to different powers to achieve a linear relationship. This is not to say that all non-linear relationships *must* be addressed by using some form of a log transformation, but rather, that using logs has been the preferred transformation choice.

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[6] Staff/803, Dlouhy/1-2.

**Q. Is there any reason to transform the variables in the way the Company did in its two Export regressions even though it would be likely rejected by an academic journal?**

A. Yes. Ultimately, the goal of any econometric model is to model the process that generates the data. All else being equal, log transformations are better than the odd combination of transformations chosen by the Company because they are much more econometrically sound. However, if an unorthodox method to transform variables is drastically more effective at forecasting than a more econometrically sound method, then the unorthodox method is ultimately more useful. As stated before, this is why I do not recommend any changes to the Company's **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]**

**Q. How do you advocate that the Company address this inconsistency?**

A. I propose reconfiguring the Company's **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** to instead rely on log transformations rather than **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Through its own model experimentation, I found the following models to both better adhere to econometric norms while still providing the predictive power necessary to accurately forecast EIM benefits:

**[BEGIN CONFIDENTIAL]**

[redacted]

**[END CONFIDENTIAL]**

**Q. What evidence do you have that this regression better represents the EIM benefits for [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]?**

A. I determined that this regression is better than the Company's current regression for four reasons:

1. This model is more consistent with the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** and the Company provided no reason that these models should differ in theory.
2. Log transformations are more econometrically sound than the current mix of square roots and squared terms that the Company currently employs.
3. The model fit of my proposed regression is notably higher than the Company's while still using the same number of regressors, as determined by the two models' R-square and Adjusted R-square. See Exhibit 803 for a full comparison of model fits between the Company's and my **[BEGIN CONFIDENTIAL]** [redacted].[7] **[END CONFIDENTIAL]**
4. My proposed regression also forecasts EIM benefits as well as, if not better than, the regression chosen by the Company, as demonstrated in Figure 2. In Figure 2, notice that for most months, both PAC's and my models forecast the daily EIM benefits about the same for most

[7] Staff/803, Dlouhy/1-3.

periods. Also notice that my model fits benefits far more accurately during large spikes, particularly the spike in the middle of 2020.

**[BEGIN CONFIDENTIAL]**

***Figure 2: Comparison of PACE Export Models***

[redacted]

**[END CONFIDENTIAL]**

**Q. How do your proposed alternate regressions change the Company's forecasted energy transfer benefit?**

A. The change to the PACE Export model lowers the Company's total energy transfer benefit by approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. On an Oregon-allocated basis, this amounts to a reduction of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

**Q. What adjustment do you propose for the Company's proposed energy transfer benefit in the 2022 TAM?**

A. I recommend lowering the Company's energy transfer benefits by **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** and **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** on an Oregon-allocated basis.

**Q. How would your recommended change affect Net Power Costs (NPC)?**

A. NPC would increase by **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** on an Oregon basis, because energy transfer benefits act as an offset to NPC.

## ISSUE 2 – MARKET CAPACITY LIMITS

**Q. Please provide an overview of your testimony relating to this issue, including your recommended adjustment.**

A. In this section, I address the following issues relating to PacifiCorp's market capacity limits in its GRID model:

- What are market capacity limits (market caps) and why are they needed in GRID?
- How has PacifiCorp traditionally modeled market caps, and why was that method chosen?
- How has PacifiCorp proposed to change its market caps, and what are the merits of its proposed change?
- How have I analyzed market caps, and what adjustments do I recommend?

I recommend reducing the Company's net power costs by **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, or **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** on an Oregon-allocated basis. This recommendation is based on rejecting the Company's proposal to change the way market caps are calculated and maintaining the previously approved method for calculating market caps.

**Q. What are market capacity limits (market caps) and how do they factor into the Company's GRID model?**

A. As described in the Company's opening testimony, the GRID model assumes that all markets have unlimited market depth and are not burdened by load requirements, transmission constraints, market illiquidity or changing market prices. In reality, all of these things matter, leading the Company to place an ad hoc market cap on market activity to proxy for these concerns.[8]

**Q. How many markets does the Company trade in?**

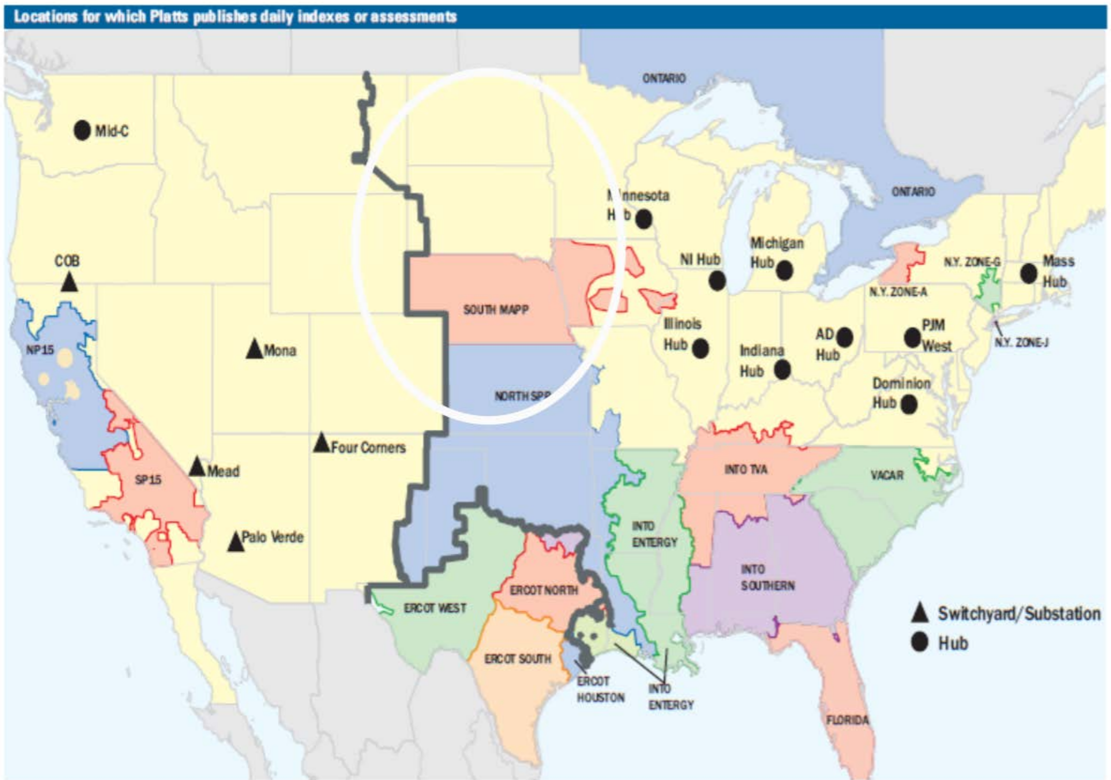
A. The Company operates in six market hubs, which are Mona, California-Oregon Border (or COB), Four Corners, Mid-Continental (or Mid-C), Palo Verde, and Mead.

**Q. Where are each of these trading hubs located?**

A. The six trading hubs are located throughout the western interconnection. I include a map of major trading hubs in the US in Figure 3.

[8] PAC/100, Webb/9.

*Figure 3: US Electricity Market Hubs*[9]




**Q. How important are each of these markets with regards to the Company's overall power cost?**

A. Table 1 presents the total sales made at each hub 2013-2020. Since 2013, over $1.3 billion of off-system sales have taken place at the Palo Verde hub, which makes it responsible for over half of all off-system sales in that period. There is still a significant amount of sales at each hub, with each hub having at least $130 million over the same interval.

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[9] This figure can be found on slide 3 at the following URL: https://www.spp.org/documents/31489/trading%20hub%20discussion1.pdf.

**[BEGIN CONFIDENTIAL]**

***Table 1: Total Off-System Sales 2013-2020[10]***

| Hub | Sales |
|---|---|
| COB | [redacted] |
| Four Corners | [redacted] |
| Mead | [redacted] |
| Mid Columbia | [redacted] |
| Mona | [redacted] |
| Palo Verde | [redacted] |

**[END CONFIDENTIAL]**

**Q. How has the Company traditionally modeled market caps prior to this filing?**

A. The Company based its market caps on "the highest of four most recently available relevant averages for each trading hub, each month, and differentiated by on- and off-peak hours."[11] This has been done since being authorized as part of the 2013 TAM.[12] I will refer to this approach as the "maximum of averages" throughout the rest of this testimony.

**Q. How does the Company propose that market caps be calculated in the 2022 TAM?**

A. Rather than use the maximum of averages value over the last four years, the Company proposes that the market cap at each hub be calculated as the *average* of the average monthly capacity at each hub differentiated by on-

[10] Values in Table 1 compiled from the workbook "2013-2020 Combined STF CONF".
[11] PAC/100, Webb/10.
[12] *In re PacifiCorp*, OPUC Docket No. UE 245, Order No. 12-409 at 7-8 (Oct. 29, 2012).

and off-peak hours.[13] I will refer to this as the "average of averages" technique throughout the rest of this testimony.

**Q. Why does the Company feel the need to model the market caps in this way rather than the method it has employed since 2013?**

A. The Company noted in its most recent rate case that GRID has chronically over-forecasted off-system sales. This analysis was corroborated by Staff's analysis and the acknowledged by the Commission in UE 374.[14] The Commission suggested that PacifiCorp may be able to make targeted forecast adjustments to remedy specific issues with its under-recovery.[15]

**Q. Please summarize your analysis of market caps as a part of this docket.**

A. In analyzing this issue, I did the following:

- Reviewed the Commission's original treatment of market caps when the issue first came up in the 2013 TAM.
- Investigated the Company's claims that the current system to determine market caps leads to a repeated under-recovery of net power costs.
- Formed a recommendation on how the Company should implement market caps into its current GRID model and its future AURORA model.

[13] PAC/100, Webb/10-11.
[14] *In re PacifiCorp*, OPUC Docket No. UE 374, Order No. 20-473 at 129-131 (Dec. 18, 2020).
[15] PAC/100, Webb/10-11.

- Adjusted the Company's workpapers with my recommended market caps and made the necessary adjustments to the 2022 TAM.

**Q. How has the Commission previously treated market caps in PacifiCorp's GRID model?**

A. The Commission approved the use of the "maximum of averages" approach upon approval in the 2013 TAM and the Company has used this approach since then.

**Q. What were Staff's previous arguments supporting the current structure to model market caps in GRID?**

A. In the 2013 TAM under Docket No. UE 245, Staff noted that market caps are an inherently unrealistic restriction on off-system sales and should not even be in the model in the first place.[16] In its opening testimony, Staff advocates against using "average of averages" technique, stating that may unnecessarily restrict sales at a trading hub when the sales are actually possible.[17]

To correct for this, Staff proposed two possible amendments to the GRID model. At the time, Staff supported not imposing a market cap at all, as doing so does not truly reflect how the Company transacts in the market.[18] If the Commission at the time did not agree with this recommendation, Staff

[16] UE 245 - Staff/100, Schue/20.
[17] UE 245 - Staff/100, Schue/15.
[18] UE 245 - Staff/100, Schue/16-17.

proposed the "maximum of averages" approach as an alternative acceptable method to implement market caps in GRID.[19]

**Q. Did PacifiCorp make similar arguments in the 2013 TAM that it uses to justify its proposal in this case?**

A. Yes. In the 2013 TAM, the Company claimed that modeling market caps using the "average of averages" method would help offset the over-forecasting of sales.[20] Staff noted that while sales were indeed over-forecasted, hourly sales varied dramatically and imposing unrealistic constraints on the model should not be the way to address this shortcoming.[21]

**Q. Do you still think that this argument is relevant in the 2022 TAM?**

A. Yes, the argument remains relevant. Even if the Company's model is not properly forecasting its off-system sales, I believe that the best solution is to make the model more realistic instead of imposing increasingly fallacious assumptions to counter other model shortcomings. In its current state, GRID does not reflect this reality; further lowering the market cap does not bring GRID closer to a market that reflects how participants interact with each other.

Additionally, I would like to point out the Company had intended to implement its new AURORA model in the 2022 TAM and that the Company will use AURORA beginning with the 2023 TAM. AURORA is a much more sophisticated model than GRID that can accommodate more subtlety in

[19] *Id.*
[20] UE 245 - Staff/100, Schue/14.
[21] UE 245 - Staff/100, Schue/14-15.

modeling off-system sales. I do not believe it is the appropriate to move from the more realistic “maximum of averages” to the “average of averages” given that it is an inferior method and this is the Company’s last year to use the GRID model for its NPC forecast.

**Q. Will switching over to AURORA help mitigate some of the Company’s forecasting issues for off-system sales?**

A. I believe that AURORA can and should be allowed to operate under the same market cap constraints that its predecessor GRID model had in order to determine if it does a better job of forecasting the Company’s off-system sales, and that adopting a change to market caps in the current TAM would present an obstacle to this. Although I do not want to constrain future decision-making by mandating that AURORA use the current market caps, I find it improper to adjust the market caps downward at this time. In response to Data Request 16, the Company claimed that Aurora would continue to make the same forecasting errors without providing any concrete evidence. The Company says:

**[BEGIN CONFIDENTIAL]**

[redacted]

[redacted][22]

**[END CONFIDENTIAL]**

I find this to be an unfair representation of AURORA's expected capabilities. In the 2022 TAM, the Company identifies that two reasons that GRID needs market caps are "transmission constraints" and "static assumptions about market prices that prevent the Company from making sales at the forecasted price."[23] A quick scan of the front page of Energy Exemplar's AURORA website advertises three model features that addresses these concerns: dynamic and volatile markets, uncertainty analysis, and nodal pricing. While my practical experience with Aurora is limited at this point, I have attended workshops with Energy Exemplar employees who have demonstrated that AURORA is indeed capable of implementing these features. I include a screenshot of Energy Exemplar's website in Figure 4 to illustrate this point, with these features highlighted. For these added reasons, I once again recommend maintaining the "maximum of averages" approach.

[22] Staff/802, Dlouhy/3.
[23] PAC/100, Webb/9.

***Figure 4: AURORA Website Homepage***

Energy Exemplar

ENGLISH SOLUTIONS RESOURCES TRAINING NEWS ABOUT US CONTACT US CLIENT LOGIN

Electric modeling software with that focuses on fast results and ease of use.

## The Electric Modeling Forecasting and Analysis Software to Save Time and Money

Aurora is the electric modeling forecasting and analysis software that is trusted, easy to learn and user-focused. Its integrated databases, quickly customizable changes and user-friendly interface deliver outcomes at the speed your organization needs. Aurora enables the highest level of software integration, model control and ease of data exchange, saving you time and money. Time-saving features include user-definable screens, reports and graphs; robust scenario management; automated data inputs; and full user access to all inputs and outputs.

This market modelling software delivers the capability to produce price forecasts, value analysis, uncertainty analysis and automated system functionality. It also includes one of the finest databases available.

Aurora was developed to model a dynamic and volatile marketplace. Whether its wind and solar modeling, storage integration and long-term expansion, nodal FTR analysis or ancillary services, Aurora electricity forecasting and analysis can help your organization make confident decisions.

Aurora is backed industry leading customer support. Our dedicated support experts work to ensure that every customer succeeds.

*"I tell people in my industry that they had better look at customer support. At the end of the day, if they choose a solution that doesn't have good customer support, it will be them in the hot seat. Energy Exemplar by far has the best support." Senior Planner/Economist, Large Utility*

*"The dedicated support staff at Energy Exemplar provides the best customer service I have ever seen."*

**Q. The Company cited the Commission's Order in the general rate case UE 374 and Staff's analysis that the Company has under-recovered off-system sales as reason to reopen the issue of market caps. Did the Company leave out any important arguments when referencing Staff's analysis cited in the UE 374 order?**

A. Yes. The Company neglected to mention that Staff also concluded that GRID also over-forecasts purchases from market hubs using GRID.[24] Therefore, the over-forecasting of sales lamented by the Company is at least partially offset by the over-forecasting of purchases that the Company fails to mention. This is another reason why I recommend the continued use of the "maximum of averages" approach used since the 2013 TAM.

**Q. Do you attempt to conduct any other analysis concerning market caps?**

A. Yes. In Confidential Staff Data Request 15, I requested that the Company provide me with 20 years of actual off-system sales as well as GRID-forecasted off-system sales.[25] Although the "maximum of averages" market cap methodology was implemented in 2013, I hoped to compare forecasted and actual sales both before and during the "maximum of averages" market cap regime in order to determine whether it appears that the market caps indeed had any effect on the claimed disparity between the Company's actual and forecasted off-system sales.

[24] UE 374 - Staff/2400, Gibbens/20-21.
[25] Staff/802, Dlouhy/2.

The Company objected to this request, provided the workpapers needed to find this difference from the 2013 TAM onward, and directed me to the resources to conduct its own analysis. Further, the Company noted that the workpapers it directed me to use are not perfectly comparable because **[BEGIN CONFIDENTIAL]** [redacted][26] **[END CONFIDENTIAL]**

Because I received information that neither encompasses a long enough timeline nor answers the question I hoped to ask, I was not able to properly answer this question.

**Q. Did you attempt to find the difference between GRID-forecasted sales and actual sales since the imposition of market caps in 2013 to the best of its abilities?**

A. Yes. Using the sources provided by the Company in response to Staff Data Request 15, I compared the total annual actual off-system sales to the GRID forecasted sales. The results of this comparison are contained below in Figure 5. Since 2016, actual off-system sales have been higher than projected every year. As pointed out in the Company's response to Staff Data Request 15, I understand that GRID does not account for the offsetting purchases and sales that actually happen in the marketplace. However, the Figure below, which uses the best data identified by the

[26] Staff/802, Dlouhy/2.

Company, leads me to believe that the Company's concerns of under-recovery are overstated.

**[BEGIN CONFIDENTIAL]**

***Figure 5: Projected vs. Actual Off-System Sales*[27]**

[redacted]

**[END CONFIDENTIAL]**

**Q. How do you recommend that the Company adjust its GRID model?**

A. I recommend that PacifiCorp continue using the "maximum of averages" method to calculate the off-system sales in the 2022 TAM.

**Q. How do market caps change when using the "maximum of averages" approach instead of the "average of averages" approach?**

A. Under PacifiCorp's proposed "average of averages" approach, the mean market cap is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. When using the currently approved "maximum of averages" approach,

[27] Figure compiled from the "2013-2020 Combined STF CONF" workpaper and the workpapers sent in response to Data Request 15. See Staff/802, Dlouhy/2.

which I support, the mean market cap rises by **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. It is worth reiterating that market caps are calculated for both on- and off-peak periods, so each market has two caps. I include a more detailed difference of the Company's and my proposed market caps below in Table 2:

**[BEGIN CONFIDENTIAL]**

***Table 2: Average Market Cap by Hub & On/Off Peak (MW)[28]***

| Hub | Company's Market Cap | Staff's Market Cap | Difference |
|---|---|---|---|
| COB HLH | [redacted] | [redacted] | [redacted] |
| Four Corners HLH | [redacted] | [redacted] | [redacted] |
| Mid-Columbia HLH | [redacted] | [redacted] | [redacted] |
| Mona HLH | [redacted] | [redacted] | [redacted] |
| Palo Verde HLH | [redacted] | [redacted] | [redacted] |
| Mead HLH | [redacted] | [redacted] | [redacted] |
| COB LLH | [redacted] | [redacted] | [redacted] |
| Four Corners LLH | [redacted] | [redacted] | [redacted] |
| Mid-Columbia LLH | [redacted] | [redacted] | [redacted] |
| Mona LLH | [redacted] | [redacted] | [redacted] |
| Palo Verde LLH | [redacted] | [redacted] | [redacted] |
| Mead LLH | [redacted] | [redacted] | [redacted] |

**[END CONFIDENTIAL]**

**Q. How do you calculate its recommended adjustment to the 2022 TAM to reflect the "maximum of averages" approach to market caps?**

A. I calculate its recommended adjustment by modifying the Company's workpapers created by the GRID model by replacing the Company's market caps based on the "average of averages" technique with my preferred

[28] Table compiled from Staff adjustments to "ORTAM22 Dir_Market Capacity DEC20 CONF" workpaper.

"maximum of averages" technique. The Company has provided a version of the model under the "maximum of averages" scenario in the "GRID_Market Caps" tab of the workpaper titled "ORTAM22 Dir_Market Capacity DEC20 CONF." The Company notes that the change from the "maximum of averages" method to the "average of averages" method will add approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** to the Company's Net Power Costs, which amounts to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** on an Oregon-allocated basis.

**Q. On May 25, 2021, PacifiCorp issued a set of corrections to the 2022 TAM, including a change to its market caps. How does this change your analysis?**

A. Upon seeing the Company's correction to its market cap methodology, I reviewed its calculation of its proposed market caps. In its filing, the Company noted that it erroneously omitted sales from January 2020 through June 2020. I found that changing the date range did very little to change the market caps calculated by the "maximum of averages" approach, particularly at the large Palo Verde hub. For this reason, I see no reason to change its adjustment.

**Q. Are there any other reasons to reject the Company's upcoming corrections to market caps in its rebuttal testimony?**

A. Yes. The six additional months that the Company wants to use to calculate market caps largely occurred during the onset of the COVID-19 pandemic. This period was notable for the exceptionally sharp drop in energy demand as many people began working from home. I believe that using off-system sales from January 2020 through June 2020 to calculate market caps will artificially deflate the Company's suggested market cap and lead to further distortions that I advocated against earlier in this section. While the change was negligible in the "maximum of averages" approach, I am concerned that the effects will be far more pronounced in the "average of averages" approach.

**Q. In its issues list, the Commission expressed a desire to learn about how the changes in market caps affect the volume of sales at each market cap and the unit cost of sales.[29] Have you conducted analysis to answer either of these questions?**

A. To fully answer to all the items concerning market caps on the Commission's Issues List would likely include a full run of the Company's GRID model to both:

- See which Company assets are dispatched under each market cap regime, and
- See which hubs and times the GRID-forecasted sales will occur at.

Given timing constraints, I performed back-of-the envelope calculations to communicate the scale of the added sales and where I expect them to occur. I would like to reiterate that that the calculation below are preliminary.

[29] UE 390 – Commission's Issues List, Page 3 (May 21, 2021).

According to the workpaper "2013-2020 Combined STF CONF," the weighted average sales price across the six market hubs in 2020 was **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per MWh, and my adjustment to market caps reduces off-system sales by **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. This implies that my adjustment would raise off-system sales by approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** MWh. The Company states that GRID assumes unlimited market depth,[30] so I expect these added sales would likely be distributed proportionally to the changes in market caps across each of the six market hubs presented in Table 2. I will continue to refine my response to this request as well as PacifiCorp's response in its reply testimony.

**Q. What is your recommended adjustment to the 2022 TAM with regards to market caps?**

A. I recommend reducing the Company's net power costs by **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** and **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** on an Oregon-allocated basis.

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

A. Yes.

[30] PAC/100, Webb/9.

CASE: UE 390
WITNESS: CURTIS DLOUHY

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

## STAFF EXHIBIT 801

## Witness Qualification

## June 9, 2021

**WITNESS QUALIFICATION STATEMENT**

| | |
|---|---|
| NAME: | Curtis Dlouhy |
| EMPLOYER: | Public Utility Commission of Oregon |
| TITLE: | Senior Economist<br>Energy Rates, Finance, and Audit Division |
| ADDRESS: | 201 High St. SE Ste. 100<br>Salem, OR 97301-3612 |
| EDUCATION: | PhD, Economics<br>University of Oregon,<br>Eugene, OR<br><br>Master of Science, Economics<br>University of Oregon,<br>Eugene, OR<br><br>Bachelor of Arts, Economics & Math<br>Nebraska Wesleyan<br>University, Lincoln, NE |
| EXPERIENCE: | I have been employed by the Oregon Public Utility Commission (OPUC) since June 2020 in the Energy Rates, Finance, and Audit Division. 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, and UE 390(ongoing).<br><br>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 covered various 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 cost and economic analysis for the Graduate Teaching Fellows Federation as a member of their contract bargaining team. |

CASE: UE 390
WITNESS: CURTIS DLOUHY

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 802

# Data Requests in Support Of Opening Testimony

# June 9, 2021

**Pages 1-3 are confidential and**

**IS CONFIDENTIAL AND SUBJECT TO**

**PROTECTIVE ORDER NO. 21-086**

CASE: UE 390
WITNESS: CURTIS DLOUHY

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 803

## Exhibits in Support
## Of Opening Testimony

**June 9, 2021**

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**PROTECTIVE ORDER NO. 21-086**

CASE: UE 390
WITNESS: CURTIS DLOUHY

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 804

## Attachment in Support
## Of Opening Testimony

## June 9, 2021

# ECON2228 Notes 10

Christopher F Baum

Boston College Economics

2014–2015

# Chapter 12: Serial correlation and heteroskedasticity in time series regressions

What will happen if we violate the assumption that the errors are not *serially correlated*, or *autocorrelated*? We demonstrated that the OLS estimators are unbiased, even in the presence of autocorrelated errors, as long as the explanatory variables are strictly exogenous.

This is analogous to our results in the case of heteroskedasticity, where the presence of heteroskedasticity alone does not cause bias nor inconsistency in the OLS point estimates. However, following that parallel argument, we will be concerned with the properties of our interval estimates and hypothesis tests in the presence of autocorrelation.

OLS is no longer BLUE in the presence of serial correlation, and the OLS standard errors and test statistics are no longer valid, even asymptotically. Consider a first-order Markov error process:

$$u_t = \rho u_{t-1} + e_t, \ |\rho| < 1 \tag{1}$$

where the $e_t$ are uncorrelated random variables with mean zero and constant variance.

What will be the variance of the OLS slope estimator in a simple $y$ on $x$ regression model? For simplicity let us center the $x$ series so that $\bar{x} = 0$. Then the OLS estimator will be:

$$b_1 = \beta_1 + \frac{\sum_{t=1}^{T} x_t u_t}{SST_x}$$

where $SST_x$ is the sum of squares of the $x$ series.

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In computing the variance of $b_1$, conditional on $x$, we must account for the serial correlation in the $u$ process:

$$\begin{aligned}
Var\left(b_1\right) &= \frac{1}{SST_x^2} Var\left(\sum_{t=1}^{T} x_t u_t\right) \\
&= \frac{1}{SST_x^2}\left(\begin{array}{c} \sum_{i=1}^{T} x_t^2 Var(u_t) + \\ 2\sum_{t=1}^{T-1}\sum_{j=1}^{T-1} x_t x_{t-j} E\left(u_t u_{t-j}\right) \end{array}\right) \\
&= \frac{\sigma^2}{SST_x} + 2\left(\frac{\sigma^2}{SST_x^2}\right)\sum_{t=1}^{T-1}\sum_{j=1}^{T-1} \rho^j x_t x_{t-j}
\end{aligned}$$

where $\sigma^2 = Var(u_t)$ and we have used the fact that $E\left(u_t u_{t-j}\right) = Cov\left(u_t u_{t-j}\right) = \rho^j \sigma^2$ in the derivation.

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Notice that the first term in this expression is merely the OLS variance of $b_1$ in the absence of serial correlation. When will the second term be nonzero? When $\rho$ is nonzero, and the $x$ process itself is autocorrelated, this double summation will have a nonzero value.

As nothing prevents the explanatory variables from exhibiting autocorrelation (and in fact many explanatory variables take on similar values through time) the only way in which this second term will vanish is if $\rho$ is zero, and $u$ is not serially correlated. In the presence of serial correlation, the second term will cause the standard OLS variances of our regression parameters to be biased and inconsistent.

In most applications, when serial correlation arises, $\rho$ is positive, so that successive errors are positively correlated. In that case, the second term will be positive as well. Recall that this expression is the true variance of the regression parameter; OLS will only consider the first term. In that case OLS will seriously underestimate the variance of the parameter, and the $t-$statistic will be much too high.

If on the other hand $\rho$ is negative, so that successive errors result from an "overshooting" process, then we may not be able to determine the sign of the second term, since odd terms will be negative and even terms will be positive. Surely, though, it will not be zero. Thus the consequence of serial correlation in the errors, particularly if the autocorrelation is positive, will render the standard $t-$ and $F-$statistics useless.

# Serial correlation in the presence of lagged dependent variables



A case of particular interest, even in the context of simple $y$ on $x$ regression, is that where the explanatory variable is a lagged dependent variable. Suppose that the conditional expectation of $y_t$ is linear in its past value: $E(y_t|y_{t-1}) = \beta_0 + \beta_1 y_{t-1}$. We can always add an error term to this relation, and write it as

$$y_t = \beta_0 + \beta_1 y_{t-1} + u_t \tag{2}$$

Let us first assume that the error is “well behaved,” i.e. $E\left(u_t|y_{t-1}\right)=0$, so that there is no correlation between the current error and the lagged value of the dependent variable. In this setup the explanatory variable cannot be strictly exogenous, since there is a contemporaneous correlation between $y_t$ and $u_t$ by construction.

In evaluating the consistency of OLS in this context we are concerned with the correlation between the error and $y_{t-1}$, not the correlation with $y_t,\ y_{t-2}$, and so on. In this case, OLS would still yield unbiased and consistent point estimates, with biased standard errors, as we derived above, even if the $u$ process was serially correlated.

But it is often claimed that the joint presence of a lagged dependent variable and autocorrelated errors, OLS will be inconsistent. This arises, as it happens, from the assumption that the *u* process in (2) follows a particular autoregressive process, such as the first-order Markov process in (1). If this is the case, then we do have a problem of inconsistency, but it is arising from a different source: the misspecification of the dynamics of the model.

If we combine (2) with (1), we really have an $AR(2)$ model for $y_t$, since we can lag (2) one period and substitute it into (1) to rewrite the model as:

$$\begin{aligned} y_t &= \beta_0 + \beta_1 y_{t-1} + \rho\left(y_{t-1} - \beta_0 - \beta_1 y_{t-2}\right) + e_t \\ &= \beta_0 (1-\rho) + (\beta_1 + \rho)\, y_{t-1} - \rho\beta_1 y_{t-2} + e_t \\ &= \alpha_0 + \alpha_1 y_{t-1} + \alpha_2 y_{t-2} + e_t \end{aligned} \tag{3}$$

so that the conditional expectation of $y_t$ properly depends on two lags of $y$, not merely one. Thus the estimation of (2) via OLS is indeed inconsistent, but the reason for that inconsistency is that $y$ is correctly modelled as $AR(2)$.

The $AR(1)$ model is seen to be a dynamic misspecification of (3). As is always the case, the omission of relevant explanatory variables will cause bias and inconsistency in OLS estimates, especially if the excluded variables are correlated with the included variables. In this case, that correlation will almost surely be meaningful.

To arrive at consistent point estimates of this model, we merely need add $y_{t-2}$ to the estimated equation. That does not deal with the inconsistent interval estimates, which will require a different strategy.

# Testing for first-order serial correlation



As the presence of serial correlation invalidates our standard hypothesis tests and interval estimates, we should be concerned about testing for it. First let us consider testing for serial correlation in the $k-$variable regression model with strictly exogenous regressors, which rules out, among other things, lagged dependent variables.

The simplest structure which we might posit for serially correlated errors is $AR(1)$, the first order Markov process, as given in (1). Let us assume that $e_t$ is uncorrelated with the entire past history of the $u$ process, and that $e_t$ is homoskedastic. The null hypothesis is $H_0$ : $\rho = 0$ in the context of (1).

If we could observe the $u$ process, we could test this hypothesis by estimating (1) directly. Under the maintained assumptions, we can replace the unobservable $u_t$ with the OLS residual $v_t$. Thus a regression of the OLS residuals on their own lagged values,

$$v_t = \kappa + \rho v_{t-1} + \epsilon_t, t = 2, ...T \tag{4}$$

will yield a $t-$ test. That regression can be run with or without an intercept, and the `robust` option may be used to guard against violations of the homoskedasticity assumption. It is only an asymptotic test, though, and may not have much power in small samples.

A very common strategy in considering the possibility of $AR(1)$ errors is the *Durbin–Watson* test, which is also based on the OLS residuals:

$$DW = \frac{\sum_{t=2}^{T} (v_t - v_{t-1})^2}{\sum_{t=1}^{T} v_t^2} \tag{5}$$

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Simple algebra shows that the *DW* statistic is closely linked to the estimate of $\rho$ from the large-sample test:

$$\begin{aligned} DW &\simeq 2\,(1-\hat{\rho}) \\ \hat{\rho} &\simeq 1-\frac{DW}{2} \end{aligned} \tag{6}$$

The relationship is not exact because of the difference between $(T-1)$ terms in the numerator and $T$ terms in the denominator of the *DW* test.

The difficulty with the *DW* test is that the critical values must be evaluated from a table, since they depend on both the number of regressors ($k$) and the sample size ($n$), and are not unique: for a given level of confidence, the table contains two values, $d_L$ and $d_U$. If the computed value falls below $d_L$, the null is clearly rejected. If it falls above $d_U$, there is no cause for rejection. But in the intervening region, the test is inconclusive. The test cannot be used on a model without a constant term, and it is not appropriate if there are any lagged dependent variables.

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In the presence of one or more lagged dependent variables, an alternative statistic may be used: *Durbin's h* statistic, which merely amounts to augmenting (4) with the explanatory variables from the original regression. This test statistic may readily be calculated in Stata with the `estat durbinalt` command.

# Testing for higher-order serial correlation



One of the disadvantages of tests for $AR(1)$ errors is that they consider precisely that alternative hypothesis. In many cases, if there is serial correlation in the error structure, it may manifest itself in a more complex relationship, involving higher-order autocorrelations; e.g. $AR(p)$. A logical extension to the test described in (4) and the Durbin "h" test is the *Breusch–Godfrey* test, which considers the null of nonautocorrelated errors against an alternative that they are $AR(p)$.

This test can readily be performed by regressing the OLS residuals on $p$ lagged values, as well as the regressors from the original model. The test is the joint null hypothesis that those $p$ coefficients are all zero, which can be considered as another $T \times R^2$ Lagrange multiplier (LM) statistic, analogous to White's test for heteroskedasticity.

The test may easily be performed in Stata using the `estat bgodfrey` command. You must specify the lag order $p$ to indicate the degree of autocorrelation to be considered. If $p = 1$, the test is essentially Durbin's "h" statistic.

An even more general test often employed on time series regression models is the Box–Pierce or Ljung–Box *Q statistic*, or "portmanteau test," which has the null hypothesis that the error process is "white noise," or nonautocorrelated, versus the alternative that it is not well behaved.

The "Q" test evaluates the autocorrelation function of the errors, and in that sense is closely related to the Breusch–Godfrey test. That test evaluates the conditional autocorrelations of the residual series, whereas the "Q" statistic uses the unconditional autocorrelations.

The “Q” test can be applied to any time series as a test for “white noise,” or randomness. For that reason, it is available in Stata as the command `wntestq`. This test is often reported in empirical papers as an indication that the regression models presented therein are reasonably specified.

Any of these tests may be used to evaluate the hypothesis that the errors exhibit serial correlation, or nonindependence. But caution should be exercised when their null hypotheses are rejected. It is very straightforward to demonstrate that serial correlation may be induced by simple misspecification of the equation. For instance, if you model a relationship as linear when it is curvilinear, or when it represents exponential growth, the linear form is misspecified.

Many time series models are misspecified in terms of inadequate dynamics: that is, the relationship between $y$ and the regressors may involve many lags of the regressors. If those lags are mistakenly omitted, the equation suffers from misspecification bias, and the regression residuals will reflect the missing terms. In this context, a visual inspection of the residuals is often useful.

User-written Stata routines such as `tsgraph`, `sparl` and particularly `ofrtplot` should be employed to better understand the dynamics of the regression function. Each may be located and installed with Stata's `ssc` command, and each is well documented with on-line help.

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```
. summarize rs r20
    Variable |       Obs        Mean    Std. Dev.       Min        Max
-------------+--------------------------------------------------------
          rs |       526    7.651513    3.553109   1.561667      16.18
         r20 |       526    8.863726    3.224372       3.35      17.18
. eststo, ti("OLS VCE"):regress D.rs LD.r20, vsquish
      Source |       SS       df       MS              Number of obs =     524
-------------+------------------------------           F(  1,   522) =   52.88
       Model |  13.8769739     1  13.8769739           Prob > F      =  0.0000
    Residual |  136.988471   522  .262430021           R-squared     =  0.0920
-------------+------------------------------           Adj R-squared =  0.0902
       Total |  150.865445   523  .288461654           Root MSE      =  .51228
------------------------------------------------------------------------------
        D.rs |      Coef.   Std. Err.      t    P>|t|     [95% Conf. Interval]
-------------+----------------------------------------------------------------
         r20 |
         LD. |   .4882883   .0671484     7.27   0.000      .356374    .6202027
       _cons |   .0040183    .022384     0.18   0.858    -.0399555    .0479921
------------------------------------------------------------------------------
(est1 stored)
```

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# Breusch–Godfrey and Q tests

```
. predict double eps, residual
(2 missing values generated)
. estat bgodfrey, lags(6)
Breusch-Godfrey LM test for autocorrelation
```

| lags(p) | chi2 | df | Prob > chi2 |
|---|---|---|---|
| 6 | 17.237 | 6 | 0.0084 |

```
                         H0: no serial correlation
. wntestq eps
Portmanteau test for white noise

 Portmanteau (Q) statistic =    82.3882
 Prob > chi2(40)           =     0.0001
```

# Correcting for serial correlation with strictly exogenous regressors



As OLS cannot provide consistent interval estimates in the presence of autocorrelated errors, how should we proceed? If we have strictly exogenous regressors (in particular, no lagged dependent variables), we may be able to obtain an appropriate estimator through transformation of the model.

If the errors follow the $AR(1)$ process in (1), we determine that $Var(u_t) = \sigma_e^2 / \left(1 - \rho^2\right)$. Consider a simple $y$ on $x$ regression with autocorrelated errors following an $AR(1)$ process. Then simple algebra will show that the *quasi-differenced* equation

$$(y_t - \rho y_{t-1}) = (1 - \rho)\,\beta_0 + \beta_1\,(x_t - \rho x_{t-1}) + (u_t - \rho u_{t-1}) \qquad (7)$$

will have nonautocorrelated errors, as the error term in this equation is in fact $e_t$, by assumption well behaved.

This *quasi-differencing* transformation can only be applied to observations 2, ..., $T$, but we can write down the first observation in static terms to complete that, plugging in a zero value for the time-zero value of $u$.

This extends to any number of explanatory variables, as long as they are strictly exogenous; we just quasi-difference each, and use the quasi-differenced version in an OLS regression.

How can we employ this strategy when we do not know the value of $\rho$? It turns out that the *feasible generalized least squares (GLS)* estimator of this model merely replaces $\rho$ with a consistent estimate, $\hat{\rho}$. The resulting model is asymptotically appropriate, even if it lacks small sample properties.

We can derive an estimate of $\rho$ from OLS residuals, or from the calculated value of the Durbin–Watson statistic on those residuals. Most commonly, if this technique is employed, we use an algorithm that implements an iterative scheme, revising the estimate of $\rho$ in a number of steps to derive the final results.

One common methodology is the *Prais–Winsten* estimator, which makes use of the first observation, transforming it separately. It may be used in Stata via the `prais` command. That same command may also be used to employ the *Cochrane–Orcutt* estimator, a similar iterative technique that ignores the first observation. In a large sample, it will not matter if one observation is lost. This estimator can be executed using the `corc` option of the `prais` command.

We do not expect these estimators to provide the same point estimates as OLS, as they are working with a fundamentally different model. If they provide similar point estimates, the FGLS estimator is to be preferred, as its standard errors are consistent. However, in the presence of lagged dependent variables, more complicated estimation techniques are required.

An aside on first differencing. An alternative to employing the feasible GLS estimator, in which a value of $\rho$ inside the unit circle is estimated and used to transform the data, would be to *first difference* the data: that is, transform the left and right hand side variables into differences. This would indeed be the proper procedure to follow if it was suspected that the variables possessed a *unit root* in their time series representation.

If the value of $\rho$ in (1) is strictly less than 1 in absolute value, first differencing approximates that value, since differencing is equivalent to imposing $\rho = 1$ on the error process. If the process's $\rho$ is quite different from 1, first differencing is not as good a solution as applying the FGLS estimator.

Also note that if you difference a standard regression equation in $y$, $x_1, x_2$... you derive an equation that does not have a constant term. A constant term in an equation in differences corresponds to a *linear trend* in the levels equation. Unless the levels equation already contains a linear trend, applying differences to that equation should result in a model without a constant term.

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```
. eststo, ti("GLS VCE"): prais D.rs LD.r20, nolog vsquish

Prais-Winsten AR(1) regression -- iterated estimates

      Source |       SS           df       MS      Number of obs   =       524
-------------+----------------------------------   F(  1,    522)  =     25.73
       Model |  6.56420242         1  6.56420242   Prob > F        =    0.0000
    Residual |  133.146932       522   .25507075   R-squared       =    0.0470
-------------+----------------------------------   Adj R-squared   =    0.0452
       Total |  139.711134       523    .2671341   Root MSE        =    .50505

------------------------------------------------------------------------------
        D.rs |      Coef.   Std. Err.      t    P>|t|     [95% Conf. Interval]
-------------+----------------------------------------------------------------
         r20 |
         LD. |   .3495857    .068912     5.07   0.000     .2142067    .4849647
       _cons |   .0049985   .0272145     0.18   0.854    -.0484649    .0584619
-------------+----------------------------------------------------------------
         rho |   .1895324
------------------------------------------------------------------------------
Durbin-Watson statistic (original)    1.702273
Durbin-Watson statistic (transformed) 2.007414
(est2 stored)
```

# Robust inference in the presence of autocorrelation

Just as we utilized the “White” heteroskedasticity-consistent standard errors to deal with heteroskedasticity of unknown form, we may generate estimates of the standard errors that are robust to both heteroskedasticity and autocorrelation.

Why would we want to do this rather than explicitly take account of the autocorrelated errors via the feasible generalized least squares estimator described earlier? If we doubt that the explanatory variables may be considered strictly exogenous, then the FGLS estimates will not even be consistent, let alone efficient.

Also, FGLS is usually implemented in the context of an AR(1) model, since it is much more complex to apply it to a more complex AR structure. But higher-order autocorrelation in the errors may be quite plausible. Robust methods may take account of that behavior.

The methodology to compute what are often termed heteroskedasticity- and autocorrelation-consistent (*HAC*) standard errors was developed by Newey and West; thus they are often referred to as *Newey–West* standard errors.

Unlike the White standard errors, which require no judgment to calculate, the Newey–West standard errors must be calculated conditional on a choice of maximum lag. They are calculated from a distributed lag of the OLS residuals, and one must specify the longest lag at which autocovariances are to be computed. Normally a lag length exceeding the periodicity of the data will suffice; e.g. at least 4 for quarterly data, 12 for monthly data, etc.

The Newey–West (HAC) standard errors may be readily calculated for any OLS regression using Stata's `newey` command. You must provide the "option" `lag( )`, which specifies the maximum lag order, and your data must be `tsset` (that is, known to Stata as time series data).

As the Newey-West formula involves an expression in the squares of the residuals which is identical to White's formula (as well as a second term in the cross-products of the residuals), these robust estimates subsume White's correction. Newey-West standard errors in a time series context are robust to both arbitrary autocorrelation (up to the order of the chosen lag) as well as arbitrary heteroskedasticity.

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# Computation of Newey–West standard errors

```
. eststo, ti("Newey-West"): newey D.rs LD.r20, lag(6) vsquish
Regression with Newey-West standard errors          Number of obs  =        524
maximum lag: 6                                      F(  1,    522) =      35.74
                                                    Prob > F       =     0.0000

                            Newey-West
        D.rs        Coef.   Std. Err.       t     P>|t|     [95% Conf. Interval]

         r20
         LD.     .4882883    .0816725     5.98    0.000      .3278412    .6487354
       _cons     .0040183    .0256542     0.16    0.876     -.0463799    .0544166

(est3 stored)
```

# Comparison of OLS, GLS, Newey–West estimates

```
. esttab, nonum mti se star(* 0.1 ** 0.05 *** 0.01)
```

| | OLS VCE | GLS VCE | Newey-West |
|---|---|---|---|
| LD.r20 | 0.488*** | 0.350*** | 0.488*** |
| | (0.0671) | (0.0689) | (0.0817) |
| _cons | 0.00402 | 0.00500 | 0.00402 |
| | (0.0224) | (0.0272) | (0.0257) |
| N | 524 | 524 | 524 |

Standard errors in parentheses
* p<0.1, ** p<0.05, *** p<0.01

# Heteroskedasticity in the time series context

Heteroskedasticity can also occur in time series regression models; its presence, while not causing bias nor inconsistency in the point estimates, has the usual effect of invalidating the standard errors, $t-$statistics, and $F-$statistics, just as in the cross-sectional case.

As the Newey–West standard error formula subsumes the White (robust) standard error component, if the Newey–West standard errors are computed, they will also be robust to arbitrary departures from homoskedasticity. However, the standard tests for heteroskedasticity assume independence of the errors, so if the errors are serially correlated, those tests will not generally be correct.

It thus makes sense to test for serial correlation first (using a heteroskedasticity–robust test if it is suspected), correct for serial correlation, and then apply a test for heteroskedasticity.

In the time series context, it may be quite plausible that if heteroskedasticity—variations in volatility in a time series process—exists, it may itself follow an autoregressive pattern. This can be termed a dynamic form of heteroskedasticity, in which Engle's *ARCH* (autoregressive conditional heteroskedasticity) model applies.

The simplest ARCH model, the ARCH(1), may be written as:

$$\begin{aligned} y_t &= \beta_0 + \beta_1 z_t + u_t \\ E\left(u_t^2 | u_{t-1}, u_{t-2}, \ldots\right) &= E\left(u_t^2 | u_{t-1}\right) = \alpha_0 + \alpha_1 u_{t-1}^2 \end{aligned}$$

The second line is the conditional variance of $u_t$ given that series' past history, assuming that the $u$ process is serially uncorrelated. As conditional variances must be positive, this only makes sense if $\alpha_0 > 0$ and $\alpha_1 \geq 0$. We can rewrite the second line as:

$$u_t^2 = \alpha_0 + \alpha_1 u_{t-1}^2 + \upsilon_t$$

which then appears as an autoregressive model in the squared errors, with stability condition $\alpha_1 < 1$. When $\alpha_1 > 0$, the squared errors contain positive serial correlation, even though the errors themselves do not.

If this sort of process is evident in the regression errors, what are the consequences? First of all, OLS are still BLUE. There are no assumptions on the conditional variance of the error process that would invalidate the use of OLS in this context.

But we may want to explicitly model the conditional variance of the error process, since in many financial series the movements of volatility are of key importance (for instance, option pricing via the standard Black–Scholes formula requires an estimate of the volatility of the underlying asset's returns, which may well be time–varying).

Estimation of ARCH models, of which there are many flavors, with the most common extension being Bollerslev's GARCH (generalized ARCH), may be performed via Stata's `arch` command. Tests for ARCH, which are based on the squared residuals from an OLS regression, are provided by Stata's `estat archlm` command.

## Test for ARCH effects

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```
. regress D.rs LD.r20, vsquish
```

| Source | SS | df | MS |
|---|---|---|---|
| Model | 13.8769739 | 1 | 13.8769739 |
| Residual | 136.988471 | 522 | .262430021 |
| Total | 150.865445 | 523 | .288461654 |

| | |
|---|---|
| Number of obs = | 524 |
| F( 1, 522) = | 52.88 |
| Prob > F = | 0.0000 |
| R-squared = | 0.0920 |
| Adj R-squared = | 0.0902 |
| Root MSE = | .51228 |

| D.rs | Coef. | Std. Err. | t | P>\|t\| | [95% Conf. | Interval] |
|---|---|---|---|---|---|---|
| r20 | | | | | | |
| LD. | .4882883 | .0671484 | 7.27 | 0.000 | .356374 | .6202027 |
| _cons | .0040183 | .022384 | 0.18 | 0.858 | -.0399555 | .0479921 |

```
. estat archlm, lag(6)
LM test for autoregressive conditional heteroskedasticity (ARCH)
```

| lags(*p*) | chi2 | df | Prob > chi2 |
|---|---|---|---|
| 6 | 13.361 | 6 | 0.0377 |

H0: no ARCH effects *vs.* H1: ARCH(*p*) disturbance

# Estimation of ARCH(1)

```
. arch D.rs LD.r20, vsquish nolog arch(1)
ARCH family regression
Sample: 1952m5 - 1995m12                          Number of obs   =       524
Distribution: Gaussian                            Wald chi2(1)    =     50.57
Log likelihood = -370.6064                        Prob > chi2     =    0.0000
```

| D.rs | Coef. | OPG Std. Err. | z | P>\|z\| | [95% Conf. | Interval] |
|---|---|---|---|---|---|---|
| rs | | | | | | |
| r20 | | | | | | |
| LD. | .4458543 | .0626973 | 7.11 | 0.000 | .3229699 | .5687387 |
| _cons | -.0081822 | .0235846 | -0.35 | 0.729 | -.0544071 | .0380427 |
| ARCH | | | | | | |
| arch | | | | | | |
| L1. | .3888359 | .0729199 | 5.33 | 0.000 | .2459155 | .5317562 |
| _cons | .1819778 | .0085672 | 21.24 | 0.000 | .1651864 | .1987692 |

## Estimation of GARCH(1,1)

Docket No UE 390

Staff/804
Dlouhy/48

```
. arch D.rs LD.r20, vsquish nolog arch(1) garch(1)
ARCH family regression
Sample: 1952m5 - 1995m12                        Number of obs     =        524
Distribution: Gaussian                          Wald chi2(1)      =      54.58
Log likelihood = -368.9344                      Prob > chi2       =     0.0000
```

| D.rs | Coef. | OPG Std. Err. | z | P>\|z\| | [95% Conf. | Interval] |
|---|---|---|---|---|---|---|
| rs | | | | | | |
| r20 | | | | | | |
| LD. | .4524499 | .0612444 | 7.39 | 0.000 | .332413 | .5724867 |
| _cons | -.0169603 | .0224823 | -0.75 | 0.451 | -.0610247 | .0271041 |
| ARCH | | | | | | |
| arch | | | | | | |
| L1. | .3843838 | .0727441 | 5.28 | 0.000 | .241808 | .5269595 |
| garch | | | | | | |
| L1. | -.0770956 | .0200969 | -3.84 | 0.000 | -.1164847 | -.0377064 |
| _cons | .2037547 | .0120402 | 16.92 | 0.000 | .1801563 | .227353 |

CASE: UE 390
WITNESS: SCOTT GIBBENS

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 900

# Opening Testimony

**June 9, 2021**

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

A. My name is Scott Gibbens. I am the Policy and Economic Analysis Manager employed in the Strategy and Integration Division of the Public Utility Commission of Oregon (OPUC or Commission). 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/901.

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

A. I discuss the 2022 TAM filing and Staff's analysis of the issues. Specifically, I will discuss Staff's review of and recommended Commission action regarding: load forecast and cost allocation, wind capacity factors and production tax credit (PTC) forecasts, and the Nodal Pricing Model.

**Q. How is your testimony organized?**

A. My testimony is organized as follows:

## ISSUE 1: LOAD FORECAST AND ALLOCATION

**Q. How does PacifiCorp's Load Forecast in the 2022 TAM compare to last year's 2021 TAM Load Forecast?**

A. Oregon's load is estimated to increase by 0.5 percent, or 75 GWh, from 2021 to 2022. Oregon load is forecasted to be 15,295 GWh in 2022. Due to forecasted load growth, PacifiCorp anticipates $3.3 million more than expected will be collected in NPC based on rates approved in the 2021 TAM, and has included this amount in the overall rate change for the 2022 TAM, as a reduction to NPC.[1]

**Q. How does Oregon's load forecast differ from other jurisdictions in the Company's service territory?**

A. The difference in Oregon's forecasted load between 2021 and 2022 of 0.5 percent is the largest increase in PacifiCorp's service territory.[2] Utah is the only other state expected to have an increase in energy load at 0.2 percent.[3] While all other state's loads are forecast to decrease by 2.5 percent, collectively. PacifiCorp's total load is expected to decrease by 0.6 percent from 2021 to 2022.[4] The change in Oregon load relative to other jurisdictions results in a change to Oregon's allocation of load. Oregon's system energy (SE) allocation factor changes from 25.105 to 25.369 percent and the system generation (SG) allocation factor changes from 26.023 to 26.482 percent.[5] Staff has reviewed

[1] PAC/101, Webb/1, line 46.
[2] Non-confidential Company Workpaper Webb/Allocation Factors
[3] Ibid.
[4] Ibid.
[5] PAC/101, Webb/1, columns "Factors CY 2021", and "Factors CY 2022".

the Company's updated allocation factors and finds them to be reasonable and consistent. This change in allocation results in an increase to Oregon allocated NPC of $4.8 million.[6]

**Q. How are the allocation factors calculated?**

A. The SE allocation factor is the ratio of each state's total weather-normalized energy at input divided by the total weather-normalized energy at input for the year. So as a state demands relatively more energy than other states, the SE factor will increase. The system capacity (SC) allocation factor is based on each state's contribution to the 12 monthly coincident peaks (CP). So as a state's demand increases during the monthly coincident peak, the SC factor for that state will increase. The SG factor, used to allocated generation and transmission costs, is a weighted average of 75 percent of the SC and 25 percent of the SE factors for each state.

**Q. How did Staff analyze this issue?**

A. Staff reviewed the Company's workpapers related to load forecast to ensure proper calculation of the impact. Staff focused on the load forecasts that exhibited the largest changes. Staff traditionally does not produce a full model replication of the Company's load forecast in every power cost filing, but Staff finds the forecasts reasonable on a short-term basis. Additionally, Staff notes that the Company filed a general rate case in 2020, wherein Staff performed a full model replication to further identify any potential concerns with the forecast

[6] Calculated by multiplying allocation factors from 2021 with NPC costs from 2022 and taking difference from 2022 Oregon allocated NPC.

methodology. Staff ensured that the Company had performed the same methodology in this TAM to ensure fair and consistent rates.

**Q. Does Staff propose an adjustment to Load Forecasting?**

A. No, at this time Staff has no proposed adjustments for this issue.

**Q. Does Staff propose an adjustment to the allocation factors?**

A. No. The allocation factors are consistent with the 2020 Protocol.

## ISSUE 2: WIND AND PTC FORECASTS

**Q. Please provide a background for this issue.**

A. In UE 339, PacifiCorp proposed to change the forecast methodology for the wind projects owned by the Company. Specifically, PacifiCorp proposed to change a fixed capacity factor for the life of the asset based on the generation forecasts used to determine the prudence of the project to a forecast based on a rolling 48 months of historical generation.[7] Ultimately, parties settled on a 50/50 methodology which utilizes fifty percent historical actuals, and fifty percent original P50 forecast, for a one-year basis.[8]

In UE 356, the parties agreed to a three-pronged approach that ensured customers received the benefits of economic investments related to the EV 2020 repowering projects and New Wind projects. For non-repowered wind projects, the same 50/50 methodology was utilized. For repowered wind facilities, the economic analysis from February 2018 is used to calculate the capacity factors. For all new wind facilities, the economic analysis used to justify the investment will be used in the TAM. As part of the agreement, no party will propose any changes to the wind capacity factors until the 2025 TAM.

**Q. Has the Company complied with the UE 356 stipulated methodology?**

A. Yes. Staff reviewed the Company's workpapers and found that the Company has properly included the wind capacity factors from the varying sources based on the vintage of the wind project. Only two projects have substantially

[7] PAC/100, Wilding/34.
[8] *In re PacifiCorp*, OPUC Docket No. UE 339, Order 18-421 at 4 (October 26, 2018).

differentiated generation and PTC forecasts compared to the final 2021 TAM forecast, Pryor Mountain and TB Flats Wind II, both of which were not fully operational by January 1, 2021. Because these projects either are or anticipated to be at full capacity by January 1, 2022, it is reasonable that their forecasts have increased. This customer protection helps to ensure that customers receive the benefits they were expecting for the next four years at a minimum. Staff notes that due to the increase in the level of wind generation from the wind repowering and new wind projects, net power costs are roughly $300 million less on a total Company basis than they otherwise would have been.

**Q. The Commission's first Issues List requests feedback about PacifiCorp's reporting in its initial filing on PTCs and NPC savings realized, and whether it is transparent and useful for tracking the benefits of new projects.**

A. Staff views PacifiCorp's reporting as consistent with applicable reporting requirements.[9] However, still finds that it would be beneficial if PacifiCorp were also required to provide a comparison between the forecasted NPC benefits of the Company owned-wind projects and the benefit forecasts made to justify the investment.

**Q. Does Staff have a recommendation for reporting requirements?**

A. Yes. As stated in Staff/100, Issue 1, Staff recommends the Commission direct the Company to continue to provide a discussion of the PTC and NPC benefits

[9] Staff/100, Enright/17, line 18.

of its Company-owned renewable resources, and to also include a comparison to the benefit forecasts made to justify the investment, matching the dates used in the capacity factor methodology currently approved by the Commission.

## ISSUE 3: NODAL PRICING MODEL

**Q. What is a nodal pricing model (NPM)?**

A. Nodal Pricing is a way of finding separate equilibrium prices for a vast number of locations within a given system. The model uses supply, demand, and transmission constraints to calculate the locational marginal price (LMP) at nodes on the system. Each node represents the physical location on the transmission system where energy is injected by generators or withdrawn by loads. Under a nodal pricing model, each of PacifiCorp's six states would have its own metered load boundaries (and associated price) and a day-ahead locational marginal price associated with each of PacifiCorp resources. Due to different states within PacifiCorp's service territory pursuing different energy policies, a way to separately track each state's power costs based on load and generator was necessary. Accordingly, PacifiCorp sought a third party that would operate a dispatch engine to optimize PacifiCorp's day-ahead resources and create transparent nodal pricing to enable precise power cost tracking.

**Q. Did PacifiCorp set forth potential benefits of NPM, in addition to allocation of power costs, in the 2020 Protocol?**

A. Yes. In Appendix D to the 2020 Protocol, PacifiCorp's Nodal Pricing Model Memorandum of Understanding, PacifiCorp states that "in addition to providing a method to allocate NPC, the NPM potentially offers the following benefits from using the CAISO market optimization tool:

- It provides more granular dispatch information resulting in anticipated operational cost savings.

- It allows PacifiCorp to leverage CAISO's independence as a third party market provider.
- It guarantees that the solution outcome is consistent with the CAISO EIM market solution since it is using the same exact tool and input data.
- It leverages the effort and money used to build and maintain a complex and granular Real-time network model that is used in the actual market run.

It utilizes the same schedule data for internal and external resources informing the potential for unscheduled loop flows and is informative when performing congestion management and potentially enforcing physical flow transmission constraints."[10]

**Q. When did PacifiCorp implement the NPM in its operations?**

A. The service began on January 15, 2021, and is expected to be utilized to track power costs starting in 2024.

**Q. Why did PacifiCorp choose CAISO to run its NPM?**

A. Many of the optimization systems necessary to run a nodal pricing model already exist in CAISO's "Total Market Model," which creates an LMP at the many different nodes and market hubs within its market. Further PacifiCorp has already integrated much of its system to operate within the Western EIM which

[10] 2020 Protocol, Appendix D at Exhibit B (UM 1050 – PacifiCorp Initial Filing at Exhibit PAC/101).

is also operated by CAISO. The NPM will use the same tool, network model, and input data as the EIM and any potential enhanced day-ahead market.

**Q. How is the NPM used?**

A. The NPM produces an advisory dispatch of PacifiCorp's system on a day-ahead basis which the Company utilizes in its day-ahead planning operations. Once the interim period of the 2020 multi-state protocol is over, PacifiCorp expects to utilize the NPM to track power costs beginning in 2024. PacifiCorp is currently in the process of implementing AURORA for forecasting power costs using a NPM in order to match the forecasts and actuals once the switch is made in 2024.

**Q. Why is Staff raising this issue now?**

A. Although the NPM will not be used to track power costs until 2024, customers began paying for the new model January 1, 2021. This includes an $8.4 million annual service fee paid to CAISO to perform the nodal pricing model service.[11] Apart from allowing the Company to better track costs and assign them on a more granular level, the model also represents a new dispatch algorithm. Staff believes that this more complex dispatch system, which is better integrated with CAISO's EIM, will provide cost savings through a more optimal solution to generation dispatch regardless of the fact that the model will not be used to track power costs until 2024.

**Q. Why does a nodal dispatch provide cost savings?**

[11] *In re PacifiCorp*, OPUC Docket No. UE 375, Staff/100, Gibbens/9, line 13.

A. PacifiCorp's old operational dispatch was based on a zonal model, which defines areas of limited transmission constraints and connects the zones via transmission constraints between them. Within each zone, the generation-weighted averages contributing to the constraints between each zone are the same. Under a nodal model dispatch, each individual generator is assigned a separate contribution to transmission constraints. This leads to a better-informed model that can optimize to a higher level of precision. In 2010, ERCOT changed from zonal to nodal dispatch and estimated consumer savings at $5.6 billion over the following 10 years.[12]

**Q. Has Staff raised this issue before?**

A. Yes, in the 2021 TAM, Staff raised a similar concern. The Company stated that GRID already captured the expected benefits of a superior dispatch logic in the NPM.

**Q. Is GRID a zonal or nodal model?**

A. GRID is a zonal model. The Company had hoped to perform its power cost forecast using AURORA, a nodal model, to match its new dispatch logic; however, due to delays from COVID-19, the Company was unable to make this transition and instead used GRID for forecasting NPC in 2022.

**Q. Does Staff believe that GRID already captures the benefits inherent in a switch from a zonal to a nodal model?**

A. No. By its nature, GRID has perfect foresight; however, perfect planning is not what provides the cost savings associated with the nodal model. It is instead

[12] http://www.ercot.com/news/releases/show/349

the ability to identify the impact each generator has on the overall system, something that is not built into GRID. It is akin to the difference in understanding between using a magnifying glass and a microscope to study something. GRID does not operate on the same granular level that a nodal model would.

**Q. What is Staff's recommended adjustment for this issue?**

A. Although the tracking and forecasting of costs using a nodal pricing model are not set to ensue until 2024 per the 2020 Protocol, the efficiency gains resulting from the new dispatch logic should be passed onto customers in 2022 NPC rates, particularly in light of the fact that customers are paying costs related to the NPM in rates. Because PacifiCorp contests that the benefits are not realized in the current TAM forecast rates, it has not quantified the operational benefits, despite its representations about NPM operational benefits in the 2020 Protocol. In at least one other circumstance where anticipated benefits were difficult or impossible to quantify, the Commission approved matching costs with benefits in rates. When PacifiCorp initially joined the EIM, the Commission set costs as benefits as equal in rates.[13] As such, Staff's primary recommendation is that the NPC forecast be decreased by $8.4 million to account for the benefits of the NPM model, to match the incremental costs paid by customers.

[13] *In re PacifiCorp*, OPUC Docket No. UE 287, Order No. 14-331 at Appendix A, page 4, lines 16-21 (October 1, 2014).

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

A. Yes.

CASE: UE 390
WITNESS: SCOTT GIBBENS

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 901

# Witness Qualifications Statement

**June 9, 2021**

**WITNESS QUALIFICATION STATEMENT**

| | |
|---|---|
| NAME: | Scott Gibbens |
| EMPLOYER: | Public Utility Commission of Oregon |
| TITLE: | Senior Economist<br>Energy Rates, Finance and Audit |
| ADDRESS: | 201 High St. SE Ste. 100<br>Salem, OR 97301-3612 |
| EDUCATION: | Bachelor of Science, Economics, University of Oregon<br>Masters of Science, Economics, University of Oregon |
| EXPERIENCE: | I have been employed at the Oregon Public Utility Commission (Commission) since August of 2015. My current responsibilities include analysis and technical support for electric power cost recovery proceedings with a focus in model evaluation. I have been the power cost team manager since January 2017. I have worked on the following power cost dockets: PAC UE 307, UE 309, UE 323, UE 327, UE 339, UE 344, UE 356, UE 361, and current UE 375 and UE 379. PGE UE 308, UE 310, UE 319, UE 329, UE 335, UE 346, UE 359, UE 362, and current UE 377. IPC UE 301, 305, UE 314, UE 320, UE 333, UE 336, UE 350, UE 354, UE 366, and current UE 376. I've also performed analysis and review on a variety of other issues at the Commission. I have reviewed issues and made recommendations to the Commission in the following general rate cases: AVA UG 325, UG 366 and current UG 389; NWN UG 344, and current UG 388; PAC current UE 374; PGE UE 319, and UE 335; and CNG UG 305, UG 347 and current UG 390. Prior to working for the OPUC I was the operations director at Bracket LLC. My responsibilities at Bracket included quarterly financial analysis, product pricing, cost study analysis, and production streamlining. Previous to working for Bracket, I was a manager for US Bank in San Francisco where my responsibilities included coaching and team leadership, branch sales and campaign oversight, and customer experience management. |