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June 30, 2021

Via Electronic Filing

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

RE: Docket No. UE 391– In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, 2022 Annual Power Cost Update Tariff (Schedule 125).

Attached are documents for Staff Opening Testimony

Exhibit 100-106 Enright,
Confidential Exh 100 (3-6, 9-11, 14-16, 19-20 , 22, 24, 28, 31-34, 37-38, 43, 45-16),
Confidential Exh 102 (1, 10-11, 14, 18-20, 22, 25) and
Confidential Exh 103

Exhibit 200-204 Cohen, Confidential Exh 200 (3-11, 14-22), (Exh 203 Attach A and B)
Exhibit 300-305 Hanhan, Confidential Exh 300 (2, 4-8), (Exh 303, 304 & 305 electronic)
Exhibit 400-405 Fjeldheim, Confidential Exh 400 (2-4, 6 & 10), Exh 402, 403 and 404
Exhibit 500-503 Zarate, Confidential Exh 500 (7) & Exh 50
Exhibit 600-602 Fox, Confidential Exh 600 (3 & 7 & Exh 602
Exhibit 700-702 Dlouhy
Exhibit 800-801 Max St. Brown and
Exhibit 900-901 Gibbens, Confidential Exh 900 (8, 10 & 12)

/s/ Kay Barnes
Kay Barnes
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CERTIFICATE OF SERVICE

UE 391

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 30th day of June, 2021 at Salem, Oregon

/s/ Kay Barnes

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UE 391- SERVICE LIST

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CASE: UE 391
WITNESS: MOYA ENRIGHT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

Opening Testimony

June 30, 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 Staff/101.

Q. What is the purpose of your testimony?

A. First as Staff's summary witness, I present an overview of Portland General Electric Company's (PGE or Company) 2022 Annual Update Tariff (AUT) filing, putting PGE's forecasted Net Variable Power Costs (NVPC) into perspective by contrasting them with the final forecast of NVPC in the 2021 AUT. I also present a summary of the dollar effect of Staff's adjustments before introducing the Staff members providing testimony and the forecasted expenses and revenues, modelling issues, and other issues they address. Finally, I present a summary of the adjustments and recommendations made by Staff, including hyperlinks to where each topic is discussed in this filing.

Second, I address several elements of PGE's filing, including PGE's compliance with the AUT guidelines and previous AUT orders; extended planned outages at the Pelton Round Butte facility; PGE's forecast of Energy Imbalance Market (EIM) benefits; forecasted changes to NVPC associated with the repowering project at the Faraday hydro facility; and forced outage rates for Colstrip, Carty, and Beaver.

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. PGE's responses to Staff DRs, including relevant attachments
- Staff/103. PGE workpapers relied on for Staff's analysis
- Staff/104. California Carbon Allowance and California Carbon Offset prices
- Staff/105. Documents detailing REC use in CARB compliance
- Staff/106. EIM Grid Management Charges for years 2018 through 2020.

Q. How is your testimony organized?

A. My testimony is organized as follows:

OVERVIEW OF 2022 AUT FILING

Q. Please summarize PGE's 2022 AUT filing.

A. The Company has forecasted 2022 Net Variable Power Costs (NVPC) of $511.8 million in its initial filing. This is an increase of approximately $53.9 million, or 11.8 percent, over the final 2021 NVPC forecast.[1] PGE points to a 78MWa load increase, plus higher costs associated with contract and market energy purchases and sales as drivers of the change. PGE also notes that proposed modelling enhancements (listed on pages 7 and 8 of this section) increase NVPC by $12.4 million.[2]

Q. How have the Company's expenses changed since last year's filing?

A. The 2022 forecast shows the Company spending more on natural gas and contract power purchases than in the previous year, with a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in expenses related to wholesale market purchases. See Confidential Figure 1 below for a comparison of expenses forecasted by PGE in this AUT, and forecasted expenses in the final NVPC forecast for the 2021 AUT.

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1 PGE/100, Vhora–Outama–Batzler/1, line 16 - 18.
2 PGE/100, Vhora–Outama–Batzler/9, line 5 - 7.

[BEGIN CONFIDENTIAL]

[redacted]

Figure 1 - Confidential Expenses in $ millions for each source[3]

[END CONFIDENTIAL]

The increased spending on contract power purchases is driven by a significant **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in the average purchase cost per MWh **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. The Company is currently forecasting that it will purchase **[BEGIN CONFIDENTIAL]** [redacted] **[BEGIN CONFIDENTIAL]** power from contracts compared with the previous year, however Staff understands that newly signed contracts may be added to this amount in the scheduled updates. Notwithstanding, the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in the MWh amount of purchases through contracts, the overall $ expense associated with contract purchases is **[END CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[4]

[3] Staff/102, Enright/1, Confidential Attachment A to PGE Response to Staff DR 42.
[4] Staff/102, Enright/1, Confidential Attachment A to PGE Response to Staff DR 42.

Q. What is the Company's projected fuel mix and how does it track with NVPC?

A. The Company's forecast of power generation from different sources as a percentage of its total power requirement is shown in Confidential Figure 2.

[BEGIN CONFIDENTIAL]

[redacted]

Figure 2 - Confidential Breakdown of forecasted generation by fuel type[5]

[END CONFIDENTIAL]

The initial 2022 forecast shows an increase in natural gas generation and a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in wholesale purchases, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** a change seen in the 2021 forecast. As mentioned previously, forecasted contract purchases also **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

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5 Staff/102, Enright/11, Confidential Attachment A to PGE Response to Staff DR 102, and Staff/103, Enright/8, PGE Confidential workpaper "#2022 AUT-00l"

Another interesting trend to note is the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** generation to meet load in 2021 and 2022 following the decommissioning of the Boardman coal fired generator.

Q. How has the load forecast affected this year's filing?

A. The Company has forecasted a 0.4 percent increase in load compared with its 2021 filing.[6] The load forecast, and the Company's considerations relating to Covid-19 are discussed further in Staff/800, Issue 1.

Q. Did Staff find any issues with the filing?

A. Yes. Staff noted a few errors in the filing, the majority of which were corrected by PGE through either an errata filing, email communication, discovery, or the workshop held with Staff in May 2021. This included:

1) The dollar impact of the Pelton Round Butte outage and ownership change were incorrectly reported as increasing NVPC by $3.6 and $9.3 million respectively in the Company's initial filing. This was corrected in discovery to $3.1 and $8.9 million respectively.[7,8]

2) The Company's description of the Pelton Round Butte outage listed an outage at Round Butte Unit 1.[9] This was corrected to Unit 2 by PGE in discovery.[10]

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6 PGE/100, Vhora-Outama-Batzler/10, lines 17 - 18.
7 Staff/102, Enright/2 - 3, PGE Response to Staff DR 60, and Staff/102, Enright/16 - 17, PGE Response to Staff DR 116.
8 Staff notes that this value will be revised further in-line with updates to the Company's OFPC.
9 PGE/100, Vhora-Outama-Batzler/42, lines 1 - 3.
10 Staff/102, Enright/12 - 13, PGE Response to Staff DR 114.

3) The Company's description of its EIM GHG benefits model incorrectly describes the steps included in the model. This was corrected through a red-line version of the testimony provided to Staff by PGE via email.[11]
4) As has already been clarified on the record through an errata filing by PGE,[12] the Company initially stated that it had included a $0.6 million benefit to customers from Production Tax Credits earned by the Faraday plant,[13] when in fact a $0 benefit was included in the Company's initial filing. The Company expressed its intent to include a value once more data became available.[14]

Q. Does the Company include modelling changes in this filing?

A. Yes. The Company has proposed several modelling enhancements. PGE has indicated that it expects to submit a general rate case filing shortly after the AUT filing,[15] and that if it does not file a general rate case, PGE will remove the proposed modeling enhancements from this filing.

Q. What modelling changes does PGE propose?

A. The Company proposes changes related to the following:

1) Lydia 2.0 hourly price and wind shaping model (Staff/200, Issue 2)
2) EIM energy transfer benefits forecasting model (Staff/100, Issue 2)
3) Gas optimization modelling (Staff/400, Issue 2)

11 Staff/102, Enright/26, red-line correction provided to Staff by PGE on June 8th 2021 via email.
12 PGE/100, Vhora-Outama-Batzler/49 - 50, lines 22 and 1 - 3 (errata filing, dated May 28, 2021).
13 PGE/100, Vhora-Outama-Batzler/49, lines 22 (initial filing dated April 1, 2021).
14 PGE/100, Vhora-Outama-Batzler/49 - 50, lines 22 and 1 - 3 (errata filing, dated May 28, 2021).
15 PGE/100, Vhora–Outama–Batzler/9, lines 14 - 18.

4) Variable Energy Resources (VER) System Optimization Modeling (Staff/700, Issue 1)

Q. What other issues does Staff address in its opening testimony?

A. Staff addresses the impact to forecasted NVPC related to the following issues:

1) Extended planned maintenance in 2022 at Pelton Round Butte facility (Staff/100, Issue 1)
2) Pelton Round Butte ownership change (Staff/200, Issue 3)
3) Faraday Repowering Project (Staff/100, Issue 3)
4) Transmission revenue and BPA transmission costs (Staff/300, Issue 1)
5) Beaver Modernization Project (Staff/400, Issue 3)
6) QF energy tracker (Staff/500, Issue 1)
7) Headwater Benefits Study (Staff/500, Issue 3)
8) Aggregation of Blue Marmot projects (Staff/600, Issue 1)
9) Wheatridge forecasting and performance (Staff/900, Issue 1)

B. What is the effect of Staff's proposed adjustments on forecasted NVPC?

A. Staff's proposed adjustments total ($9.3 million). Including Staff's adjustments in the forecast of NVPC would lead to a total NVPC of $502.5 million, and overall increase in NVPC in 2022 of $44.6 million, compared with 2021 NVPC.

[BEGIN CONFIDENTIAL]

#	Issue	Adjustment ($ millions)
1	Pelton Round Butte	[redacted]
2	EIM (GHG Benefits, O&M Costs)	$ (0.4)
3	Wheeling Revenues	[redacted]
4	Gas Optimization	$ (4.2)
	Total Adjustments	$ (9.3)
	Forecasted NVPC	$ 511.8
	NVPC net of Adjustments	$ 502.5

Figure 3 - Confidential Staff adjustments vs forecasted NVPC

[END CONFIDENTIAL]

Q. Please briefly summarize the opening testimony of the other Staff witnesses.

A. In Staff/200, witness Heather Cohen reviews PGE's forecasted wholesale power purchase expenses of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** and forecasted wholesale power sales revenue of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Ms. Cohen also describes PGE's revised wholesale trading operations and changes to its risk management procedures that took effect January 1, 2021. Next Ms. Cohen addresses the Company's proposed change to its Lydia methodology, before finally discussing the change of ownership at Pelton Round Butte.

In Staff/300, witness Nadine Hanhan addresses the Company's forecasted wheeling expense of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

In Staff/400, witness Brian Fjeldheim addresses the Company's forecasted natural gas related expenses of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Mr. Fjeldheim's analysis includes discussion of natural gas prices, storage, and transport. Mr. Fjeldheim then addressed gas optimization, before finally discussing the Beaver Modernization Project.

In Staff/500, witness Kathy Zarate addresses the Company's forecasted generation from Qualifying Facilities (QF) and the associated expense of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** and the change to NVPC associated with the QF expense track and true-up adjustment. Ms. Zarate also addresses the standard inputs to the MONET model, and the Headwater Benefits Study.

In Staff/600, witness John Fox addresses the expected change to the structure of the Blue Marmot QF project, and the timing of the final update to prices for contracts for the Priest Rapids and Wanapum hydro facilities

Q. What modelling issues are addressed by Staff?

A. In (Staff/200), Ms. Cohen addresses the Company's proposed change to its Lydia methodology.

In Staff/700, witness Dr. Curtis Dlouhy addresses the proposed changes to Variable Energy Resources Integration and associated language used in Schedule 125.

In Staff/800, witness Dr. Max St. Brown addresses the Company's load forecast, and its rate spread and design.

In Staff/900, witness Scott Gibbens addresses the Wheatridge Performance Report and Forecasts, along with the issues raised in PGE's opening testimony regarding regional power generation capacity.

Q. Has Staff proposed any adjustments?

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

1. Adjustment relating to spill during the major outages at Pelton Round Butte, representing a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** decrease in NVPC, as detailed in Staff/100, Issue 1.
2. Adjustments relating to EIM:
    a) Adjustment to the GHG benefit forecast resulting in a $395,629 decrease in NVPC, as detailed in Staff/100, Issue 2, Part 2.
    b) Adjustment to forecasted EIM Operations and Maintenance (O&M) costs resulting in a $44,770 decrease in NVPC, as detailed in Staff/100, Issue 2, Part 4.
3. Adjustment relating to wheeling revenues, representing a decrease in NVPC of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, as presented in Staff/300, Issue 1.
4. Adjustment relating to gas optimization, representing a decrease in NVPC of $4.2 million, as presented in Staff/400, Issue 2.

Q. Has Staff made any other recommendations?

A. Yes. Staff recommends:

1. Modifying Schedule 125 to allow PGE to include in its final November 15 forecast any updates to the scheduled on-line dates of the newly constructed Faraday Units 7 and 8, as discussed in Staff/100, Issue 3.
2. Further analysis of the Headwater Benefits Study following the Company's July update, as discussed in Staff/500, Issue 3.
3. Revising the language of Schedule 125 to include costs to integrate solar resources in the Annual Update, as discussed in Staff/700.

B. **Was the Company's filing compliant with the AUT Guidelines and the terms of the most recent 2021 AUT Order (2021 Order)?**

A. Yes. The Company's filing was timely, and compliant with the Minimum Filing Requirements for the Company's AUT filings.[16]

In accordance with the terms of the 2021 Order[17] the Company held several workshops in advance of this filing, providing information to Staff and parties regarding:

1) The methodology used in the PGE's EIM energy transfer benefits forecast
2) The methodology used in PGE's transmission resale forecast
3) Gas supply constraints at the Port Westward/Beaver Complex
4) 2022 NVPC updates and enhancements

[16] Order No. 08-505.
[17] Order No. 20-390.

These, and other issues related to compliance with the 2021 AUT Order are discussed further in Staff testimony.

Further, in accordance with the 2021 Order, the Company continued its previously agreed reporting on the Wheatridge project, including expanding its reporting to include the PPA portion of the project. This issue is discussed in Staff/900, Issue 1.

Q. Are further updates expected in the docket?

A. Yes. PGE will provide several updates to this filing. PGE will file a new forecast of NVPC in July and October with updated inputs for power, fuel, and transmission contracts and their related costs, outage forecasts, loads, and the power, gas and California Carbon Allowance (CCA) forward price curves.

In November PGE will file its final forecast of NVPC with final updates to power, gas, and CCA forward price curves, various power, fuel, and transmission contracts and their related costs, long-term customer opt-outs, and Qualifying Facility (QF) commercial operation dates.

ISSUE 1. MAJOR OUTAGE AT PELTON ROUND BUTTE (PRB)

Q. Please describe the Pelton Round Butte project.

A. The Pelton Round Butte hydro project is made up of three sets of generators

1) Three Round Butte generators located at the dam to Lake Billy Chinook (LBC), with a total capacity of 338 MW.

2) Three Pelton generators located at the Pelton dam, with a total capacity of 110 MW.

3) Generation at the Pelton Reregulating Dam, with a total capacity of 18.9 MW.

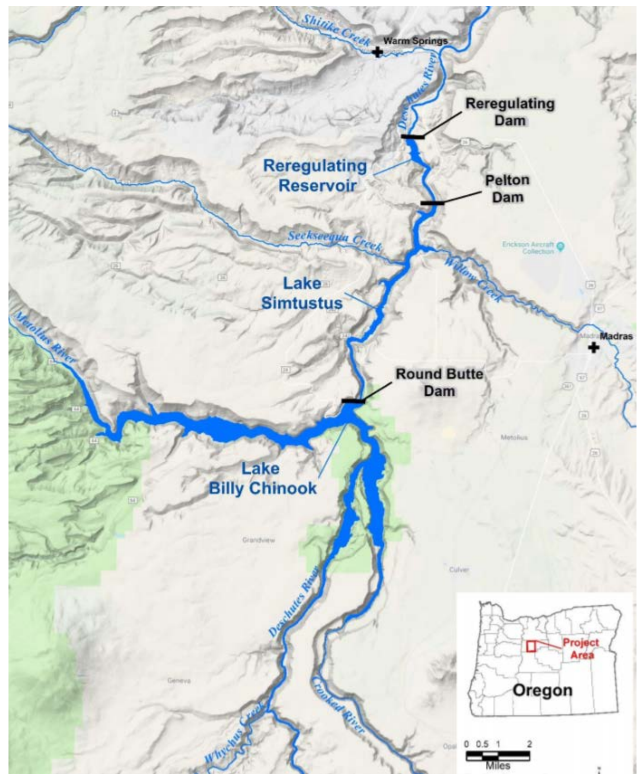

Figure 4 - Map of Pelton Round Butte, LBC, and tributaries

Q. Please describe PGE's planned maintenance at Pelton Round Butte.

A. In its initial filing, the Company described three planned major outages,[16] two at its Round Butte hydro project, and one at Pelton Round Butte. The plans for the outages have changed since the Company's initial filing, the updated plans are as follows:

[16] **[BEGIN CONFIDENTIAL** [redacted] **[END CONFIDENTIAL]**. Staff/103, Enright/9, PGE Confidential workpaper "#Copy of peltonhoverk_2009GRCFeb"

1) Outage at Round Butte Unit 2,[17] occurring in fall 2022 for a duration of six weeks, relating to a governor/exciter upgrade.

2) Outage at all three Round Butte units, occurring in fall 2022 for a duration of four weeks, to upgrade the station service 480v switchgear.

3) Outage of Pelton Unit 2, beginning in **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** 2022, for a duration of **[BEGIN CONFIDENTIAL]** [redacted] **[BEGIN CONFIDENTIAL]**,[18] relating to a governor/exciter upgrade.

Q. What is the effect of these outages in technical terms?

A. The outages will result in a loss of generation and will also impact the provision of ancillary services (AS). The effect of each outage is different.

1) Outage at Round Butte Unit 2 impacts generation at Round Butte.

2) Outage at all three Round Butte units impacts the ability of both Pelton and Round Butte to provide AS to PGE's system, and results in zero generation from the Round Butte station.

3) Outage of Pelton Unit 2 will affect the provision of AS at both Round Butte and Pelton.[19]

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[17] In Direct Testimony PGE referred to an outage at Round Butte Unit 1, however the Company clarified in discovery that the outage in fact relates to Unit 2. PGE/100, Vhora-Outama-Batzler/42, lines 1 - 3, Staff/102, Enright/12 - 13, PGE Response to Staff DR 114, and Staff/102, Enright/14, Confidential Attachment A to PGE Response to Staff DR 114.

[18] In Direct Testimony PGE detailed a six month outage of Pelton Unit 2, relating to a generator rewind and governor/exciter upgrade. In response to Staff discovery, the Company indicated that the outage plan has been adjusted to include only the governor/exciter upgrade, with a generator and rotor rewind to follow in 2023. Staff/102, Enright/12 - 13, PGE Response to Staff DR 114.

[19] This occurs due to the storage capacity of the Pelton pond being insufficient to support AS. Vhora-Outama-Batzler/43 - 44, lines 18 - 23, and 1 - 4.

Q. What effect do the outages have on NVPC?

A. The Company initially estimated that the outages at PRB would increase NVPC by $3.1 million.[20,21] Due to a significant change in scope for the Pelton Unit 2 outage, taking the outage from six months down to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, Staff expects that this value will be reduced once the Company files reply testimony.

Q. How did Staff analyze this issue?

A. Staff considered the timing of the outages, the possibility of undertaking simultaneous outages, and the possibility of avoiding spill (lost generation) during the outages.

Q. What was the result of Staff's analysis?

A. Staff concludes it may not be necessary for PGE to spill in order to accomplish its planned outages. Accordingly, Staff recommends eliminating forecasted expense associated with spill in the 2022 NVPC forecast.

Q. What is Spill?

A. Spill occurs when water bypasses a hydro generator, rather than flowing through the generator to create power. Spill can occur intentionally, for example in order to aid the passage of fish. Or spill can be forced, for example when insufficient storage capability exists above the hydro generator due to

[20] In Direct Testimony PGE erroneously estimated that the outages would increase NVPC by $3.6 million. This was corrected in response to Staff discovery. Staff/102, Enright/16 - 17, PGE Response to Staff DR 116.

[21] This value is based on the assumption that the Confederated Tribes of the Warm Springs Reservation of Oregon (the Tribes) increase their share of PRB in 2022. The Tribe's decision will be confirmed by July 1, 2021. Staff/102, Enright/16 - 17, PGE Response to Staff DR 116.

higher than expected inflows to the reservoir or the outage of a generator creating a bottleneck. Water may also be spilled when power is not needed, similar to the curtailment of wind and solar power when the resources cannot be integrated into the electric grid.[22]

Because spill represents the loss of zero-cost fuel in NVPC, and is economically expensive, utility companies put a lot of effort into optimizing their hydrological planning to maximize the value of their inflows. Such techniques include managing the levels of the reservoir ahead of an outage or contracting with third parties to decrease inflows to a reservoir.

Q. Does PGE expect to spill water during the outages?

A. Yes. The Company indicated in its initial filing that when the Round Butte units are not operating, water will be spilled.[23]

Q. Does Staff agree with this approach?

A. No. Staff does not believe that spill is strictly necessary. In fact, over the past twenty-five years, water has not once been spilled at PRB Dam. When spill last occurred in 1996 it was due to the historic 1996 flood.[24]

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[22] "Hydropower Modeling Challenges," National Renewable Energy Laboratory, April 2017. https://www.nrel.gov/docs/fy17osti/68231.pdf

[23] PGE/100, Vhora-Outama-Batzler/43, lines 10 - 11.

[24] "Water Quality Study for the Pelton Round Butte Project and the Lower Deschutes River," Report prepared for Portland General Electric & The Confederated Tribes of the Warm Springs Reservation of Oregon by MaxDepth Aquatics, Inc. (Water Report), March 2021, page 16. https://downloads.ctfassets.net/416ywc1laqmd/2rp2G0qHmVomiXoCzdSxzJ/aa198aeabd147e0596b0b99ab8b87310/pge-ctwsro-water-quality-study-2021.pdf

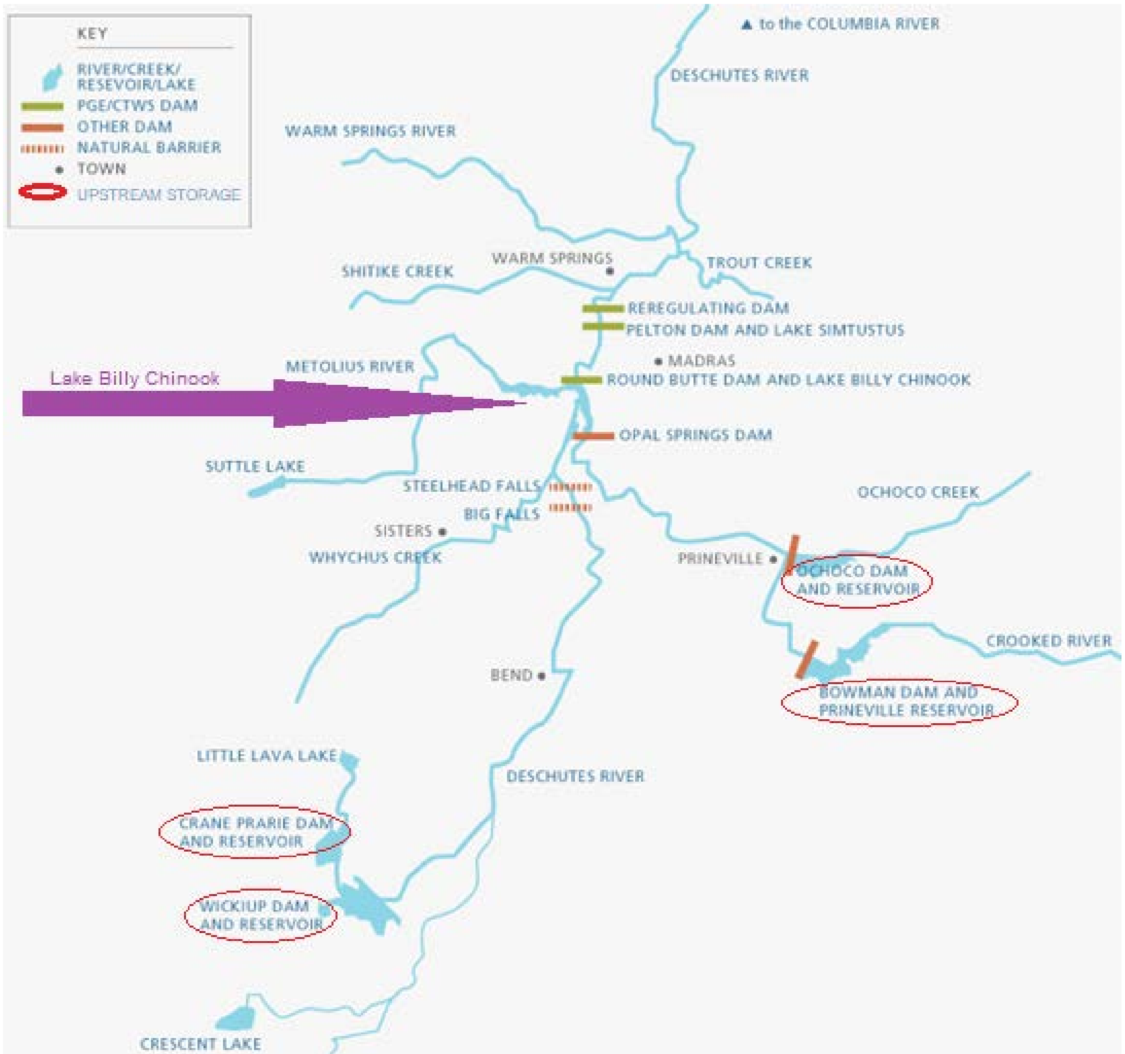

Figure 5 - Map showing location of PRB stations[25]

Observing a larger map of the locality, shown in Figure 5, one can observe Lake Billy Chinook (LBC) directly above the Pelton Round Butte dam. LBC is a 4,000 acre reservoir, which typically sees up to 10ft of change in its lake levels through the year.[26] Water inflows to LBC come from the Metolius River (39.5 percent), Crooked River (38.3 percent), and Deschutes River

25 Marked-up map sourced from PGE. https://portlandgeneral.com/about/rec-fish/deschutes-river/our-story

26 Ibid.

(22.2 percent).[27] In the period during which the outages are forecasted, discharge from each of these rivers is below average. Staff has estimated the inflows to LBC during the outage as a percentage of average annual inflows in Confidential Figure 6. This suggests that the inflows into LBC are likely not high enough to force the spill of water during the outages.

[BEGIN CONFIDENTIAL]

[redacted]

Figure 6 - Confidential Estimated inflows to LBC during PRB station outage[28]

[END CONFIDENTIAL]

Furthermore, there is significant storage available upstream of LBC. As seen in Figure 5, upstream of LBC on the Deschutes River are Wickium Dam and Reservoir measuring 200,000 acre-feet,[29,30] and Crane Prarie Dam and Reservoir measuring 55,330 acre-feet, both used for irrigation.[31]

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27 Water Report, page 49.

28 Uses 50 years of historic data (1971 - 2020) downloaded from USGS National Water Information System for monitoring sites on each river closest to LBC, accessed June 23, 2021. https://waterdata.usgs.gov/nwis

29 One acre-foot equals about 326,000 gallons, or enough water to cover an acre of land, about the size of a football field, one foot deep.

30 US Bureau of Land Reclamation, https://www.usbr.gov/projects/index.php?id=91

31 US Bureau of Land Reclamation, https://www.usbr.gov/projects/index.php?id=445

Similarly, upstream of LBC on the Crooked River are Ochoco Dam and Reservoir that measures 39,000 acre-feet,[32] and Bowman Dam and Prineville Reservoir that has a capacity of 152,800 acre-feet,[33] both used for irrigation, flood control, and recreation.

[BEGIN CONFIDENTIAL]

[redacted]

Figure 7 - Confidential Historic storage levels in reservoirs upstream of LBC[34]

[END CONFIDENTIAL]

As Confidential Figure 7 shows, the reservoirs upstream of PRB will be close to their lowest levels of the year at the time of the forecasted outage at the Round Butte facility.

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32 US Bureau of Land Reclamation, https://www.usbr.gov/projects/index.php?id=248

33 US Bureau of Land Reclamation, https://www.usbr.gov/projects/pdf.php?id=222 and https://www.usbr.gov/projects/index.php?id=248

34 Uses 37 years of historic data (1984 – 2020, largest dataset available) downloaded from US Bureau of Land Reclamation's Hydromet database, accessed June 23, 2021. https://www.usbr.gov/pn/hydromet/

Q. Can PGE continue to generate power at Pelton when spilling at Pelton Round Butte?

A. Yes. The Company has indicated that when water is spilled around PRB, power generation can continue at Pelton.[35] However it must be considered that Round Butte is a much more efficient station, capable of generating 338 MW, while Pelton is a 110 MW station with Pelton Reregulating Dam also generating up to 18.9 MW. Given that Round Butte can generate so much more power with the same quantity of water, Staff is concerned that spilling past Round Butte to generate a comparatively small amount of power at Pelton may not represent the optimal use of PGE's water resources.

Q. Did Staff engage with PGE on this issue?

A. Yes. Staff consulted with PGE to learn whether the Company had engaged with any of the owners or operators of upstream storage regarding water management during the outages. The Company did not deny that this could be done, or that it may occur in the future. It simply stated that "it would be premature to reach out this early in the planning process."[36] Further, the Company indicated that it has not performed analysis to compare the costs of contracting with upstream operators against the value of lost generation.[37]

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

A. As detailed above, Staff does not believe that it is strictly necessary to spill during the outages. Not spilling during the station outage at Round Butte would

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35 Staff/102, Enright/12 - 13, PGE Response to Staff DR 114.
36 Staff/102, Enright/15, PGE Response to Staff DR 115.
37 Staff/102, Enright/15, PGE Response to Staff DR 115.

also eliminate one of PGE's stated barriers to holding simultaneous outages.[38] Staff recommends removing the portion of the cost of the PRB station outage related to spill from NVPC, which Staff estimates to be valued at **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

[38] One reason provided by PGE for not conducting the Pelton outage simultaneously with the Round Butte outage is that water spilled from the Round Butte Dam might also be spilled from Pelton if there was an unexpected outage of an in-service Pelton generator during the planned outage at Pelton (leaving one functional generator at Pelton). Staff/102, Enright/12 - 13, PGE Response to Staff DR 114.

ISSUE 2. EIM BENEFITS

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

A. PGE cannot forecast EIM benefits with MONET, so it uses three different models to separately forecast three categories of EIM benefits: energy transfer benefits,[39] GHG benefits, and flex reserve benefits.[40] Each benefit type is measured in dollars.

Q. How are EIM benefits reflected in rates?

A. EIM benefits are applied as an offset to power costs, reducing the rates paid by customers. The 2022 AUT includes:

- $5.2 million[41] in energy transfer benefits, an increase of $1.2 million[42] from the 2021 AUT;
- $2.7 million[43] in GHG benefits, a $0.3 million decrease[44] from the 2021 AUT; and
- $0.4 million estimated flexible ramping award, equal to the 2021 AUT.[45]

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39 Note that PGE uses the term "sub-hourly dispatch benefits," while the California Independent System Operator's (CAISO) uses the term "inter-regional transfers."

40 Note that PGE uses the term "flex ramp awards" to refer to revenue earned from providing flex reserves. PGE uses the term "flexible ramping benefits" (known as flexible ramping procurement diversity savings" by CAISO) to refer to a decreased need to hold reserves due to EIM participation.

41 PGE/100, Vhora-Outama-Batzler/30, line 4.

42 UE 377 Seulean-Kim-Batzler/10, Table 1.

43 PGE/100, Vhora-Outama-Batzler/30, line 10.

44 UE 377 Seulean-Kim-Batzler / 10, Table 1.

45 UE 377 Stipulating Parties/100, Soldavini-Gehrke-Kaufman-Batzler/4, line 17.

Q. What is your recommendation related to PGE's forecast of EIM benefits.

A. Staff recommends three modifications to the Company's proposed GHG benefits forecast, resulting in a $395,629 decrease in NVPC. Further, Staff rejects the Company's addition of an **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** to its forecasted EIM Grid Management Charges, resulting in a $44,770 decrease in NVPC. In total, Staff's EIM related adjustments result in a further $440,399 in EIM benefits flowing through to customers.

<u>ISSUE 2, PART 1 - ENERGY TRANSFER BENEFITS</u>

Q. Please explain how PGE forecasts its energy transfer benefits.

A. PGE's energy transfer benefits are forecasted separately to the MONET system optimization model, but based directly on the outputs of the MONET model. PGE's model treats MONET's output as a forecasted EIM base schedule. Using a forecasted EIM price, it identifies opportunities for sub-hourly dispatch benefits, measuring those benefits as the difference between EIM prices and either the Company's production cost (for thermal units), or opportunity cost (for hydro units).

Forecasted EIM trading is limited by monthly MWh trading limits that are applied collectively to hydro units and thermal units, and which are based on average historic EIM trades.

This model was first introduced in the 2021 AUT, and has been further refined in this filing.

Q. What energy transfer benefit has been forecasted?

A. PGE's forecast of EIM energy transfers totaled $5.2 million in its initial filing.[46] This value will be updated in the Company's July, October, and November filings.[47,48]

Q. How is PGE proposing to change its model in the AUT 2022?

A. PGE's enhancements to its model in this filing include:

1) Changes to the calculation of the transaction limits used in the model, specifically:

   a) Using a weighted average, rather than the simple average used in the 2021 AUT,[49]

   b) Expanding the historic dataset to three years, an increase from one year in the 2021 AUT,[50] and

   c) Including a measure to exclude extreme values from the calculation of the transaction limits.[51]

2) The modelling of increased or decreased dispatch in cases where EIM prices are more favorable than Mid-C prices, thereby increasing the forecasted EIM benefit.[52]

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[46] PGE/100, Vhora-Outama-Batzler/30, lines 3 - 4.
[47] PGE/100, Vhora-Outama-Batzler/30, lines 3 - 4.
[48] PGE/100, Vhora-Outama-Batzler/3, lines 3 - 12.
[49] PGE/100, Vhora-Outama-Batzler/26, lines 15 - 16.
[50] PGE/100, Vhora-Outama-Batzler/27, lines 7 - 9.
[51] PGE/100, Vhora-Outama-Batzler/27, lines 10 - 11.
[52] PGE/100, Vhora-Outama-Batzler/26, lines 17 - 19.

3) Calculating EIM movements for each five-minute interval as the sum of the incremental and decremental movement for each resource type (hydro and thermal).

4) Using an EIM price curve, measured relative to the Mid-C price curve over a three year historic period, which estimates the price differential between each price curve.[53]

Q. Did Staff have any concerns with this model in the 2021 filing? Have they been resolved?

A. Yes. In the last AUT filing, Staff expressed concerns with the transaction limits set on forecasted EIM trades. As agreed in the settlement stipulation to the 2021 AUT, PGE held a workshop with Staff and parties on EIM trading limit methodology in advance of the current filing. This included presentations from the Company on the planned enhancements to its model, which have been detailed on pages 7 and 8 of this section.

Staff was encouraged by the Company's presentation showing it intended to expand the historic period used to inform the model, its explanation of the calculations and approaches used in the model, and the comparative data provided.

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

A. Having engaged with the Company on this issue a number of times, issued discovery, and attended the workshops held in advance of the filing, Staff's

[53] PGE/100, Vhora-Outama-Batzler/27, lines 12 - 18.

recommendation is that PGE's model, including its proposed enhancements, be used for the purposes of the 2022 AUT.

Staff intends to continue to review the efficacy of PGE's model in future filings, as more historic data becomes available.

ISSUE 2, PART 2 - GHG BENEFITS

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

A. Energy exported to California to meet load in that state is subject to California's Green House Gas (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).[54]

If CAISO determines that GHG emitting generation at a node within PGE's Balancing Authority (BA) served California load, both GHG emitting and non-

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

GHG emitting resources generating at that node will be paid the GHG bid adder of the marginal unit.[55]

Q. Does all GHG emitting generation in EIM incur a GHG compliance obligation with the California Air Resources Board (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. PGE assumes that the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of its GHG revenue earning thermal generation is deemed delivered to California.[56] Consequently, PGE's model assumes that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of the Company's GHG revenue earning thermal generation incurs a CARB compliance cost.

Staff conducted discovery on this matter and found that in 2018 and 2019 an average of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of PGE's thermal generation earning GHG revenue was "deemed delivered" to California.[57]

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[55] 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

[56] June 9th 2021 phone call between PGE and Commission Staff.

[57] Staff/102, Enright/19, Confidential Attachment A to PGE Response to Staff DR 119.

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

A. There are three steps to the Company's forecast:

PGE first forecasts a GHG Award Price for the market, based on 2020 GHG prices in EIM, 2020 California Carbon Allowance (CCA) prices, and forward prices for CCAs.[58,59]

Next, the Company forecasts its 2022 GHG revenue by multiplying the forecasted GHG Award Price by the quantity of GHG MWh it was awarded in 2020.[60]

Finally, the Company derives the 2022 GHG benefit by subtracting forecasted GHG compliance costs from the 2022 GHG revenue forecast.

Q. Has Staff identified any issues with the Company's approach?

A. Yes, Staff has identified two principal issues:

1) PGE uses historic data from 2020 only, in spite of additional relevant historical data being available.

2) PGE has included unrealistic CARB compliance costs in its model, at the expense of the ratepayer.

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58 The use of both historic CCA prices and CCA forward prices allows the model to account for growth in CCA prices.

59 Note that Staff's explanation does not correspond to that provided by PGE in Vhora-Outama-Batzler/30 and 31, lines 18 - 20 and 1 - 2, due to an error in PGE's testimony. Staff/102, Enright/26, red-line correction provided to Staff by PGE on June 8th 2021 via email.

60 PGE's proposed model includes an adjustment for lower hydro generation due to the Pelton Round Butte outage, but not the Faraday Repowering Project (Faraday does not participate in the EIM).

Q. Please explain Staff's first concern regarding PGE's 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 its other EIM benefits models are derived?

A. No. The Company proposes to include three years of historic data in its calculation of both the transaction limits and EIM price curve in the EIM energy transfer benefits model, and its calculation of the EIM flex reserve benefit.

Q. What historical dataset would it be more appropriate to use in this instance, and why?

A. Staff believes that a dataset beginning in December 2018 and including the most recently available data up to a maximum of 36 months, is most appropriate. Staff's recommendation that the historic period begin in December 2018 is informed by representations made by PGE in its two most recent AUT filings.

In the 2020 AUT filing, the Company advocated for using revised GHG data due to a shift in the market in the period beginning December 2018.[61] Again in the 2021 AUT, PGE referred to this shift in the EIM GHG market.[62]

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61 UE 359 PGE/100, Niman-Kim-Batzler/13.

62 UE 377 PGE/100, Seulean-Kim-Batzler/15, lines 6 - 7.

Testimony provided by PGE on this matter has been echoed by another Oregon Investor Owned Utilities in the past two years.[63]

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

A. Staff finds that using twelve months of historic data is inconsistent with the Company's approach to devising forecasts to date, and goes against logic when a larger portion of data is available. Staff recommends using a historic period of up to 36 months to inform the model, beginning no earlier than December 2018.

Staff's adjustment results in a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in NVPC.[64]

Q. Please explain Staff's second concern, that PGE has included unrealistic CARB compliance costs in its model.

A. Staff believes that PGE has included unrealistic CARB compliance costs in its model. This is driven by two modelling choices:

a) PGE unnecessarily limits the use of CCOs for compliance in its model.

b) PGE assumes that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** GHG earning generation incurs a CARB compliance requirement even though **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** GHG earning generation is "deemed delivered" to California.

[63] UE 390 Staff/100, Enright/35, lines 1 - 6.
[64] Staff/102, Enright/18, PGE Confidential Attachment A to PGE Response to Staff DR 117

Q. Why is this issue important?

A. GHG benefits are calculated as forecasted GHG revenue less CARB compliance costs. Forecasting a realistic cost of compliance with CARB regulations is crucial, as any compliance costs incurred reduce GHG benefits flowing through to Oregon's customers.

Q. Please explain the Company's forecast of CARB compliance costs as it relates to CCOs.

A. Staff is aware that the Company has the right to combine the use of CCAs with up to four percent CCOs when fulfilling its compliance obligation with CARB,[65] with no more than 50 percent of those CCOs generated by projects outside of California.

Using CCOs for compliance with CARB results in a cheaper compliance cost. For example, CCO futures are currently reported by ICE (albeit in a fairly illiquid market), with prices averaging $13.99, while comparable ICE CCA futures prices average $19.67.[66] ICE futures prices are used as direct inputs to PGE's model to calculate its CARB compliance costs.

Historic data shows that PGE **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** from this price differential in the past, using **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[67] in the 2018 – 2020 compliance period.

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

66 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. Staff/104, Enright/1 - 2.

67 Staff/102, Enright/22, Confidential Attachment A to PGE Response to Staff DR 121.

Q. What is Staff's concern?

A. In its forecast of its CARB compliance costs, the Company has limited its use of CCOs to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, effectively increasing NVPC by **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[68]

Staff queried this modelling choice and learned that PGE does not currently have CCOs from projects that provide direct environmental benefits in the state of California. Nevertheless, the Company is currently investigating options to exchange CCOs in its inventories with CCOs sourced from projects that provide direct environmental benefits in the state of California.[69]

Q. Does Staff have a recommendation relating to the Company's forecasted use of CCOs?

A. Yes. Staff recommends adjusting PGE's model to reflect the use of CCOs up to the maximum allowable limit of four percent. This results in an adjustment of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, acting as a reduction to NVPC.

Q. Please explain the Company's forecast of CARB compliance costs as it relates to energy "deemed delivered" to California.

A. As mentioned on page 28 of this section, PGE receives GHG revenue for all incremental generation above its base schedule, but it incurs a GHG compliance obligation only on the portion of the generation "deemed delivered"

[68] Staff/103, Enright/7, PGE Confidential workpaper "#14GHG_workpaper_MFR_4-01-21 Filing"
[69] Staff/102, Enright/20 - 21, PGE Response to Staff DR 121.

to California. Staff discovery showed that over the past two years, an average of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of the MWhs creating GHG revenue for PGE were "deemed delivered" to California.[70]

In spite of this, PGE's forecast of 2022 CARB compliance costs assumes **[BEGIN CONFIDENTIAL]** [redacted] **[BEGIN CONFIDENTIAL]** of thermal GHG revenue earning MWh will incur a compliance obligation.

Q. Does Staff have a recommendation?

A. Yes. Staff recommends adjusting PGE's model to reflect **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** percent of PGE's GHG revenue earning MWh incurring a compliance requirement. This adjustment results in a $205,736 decrease in NVPC.

Q. Did Staff investigate any other issues relating to the Company's compliance with CARB?

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.[71] CARB refers to this as an "RPS Adjustment." Any RECs used in compliance must have been generated by facilities that have been approved by the California Energy Commission as meeting California RPS standards. Public records show that

[70] Staff/102, Enright/19, Confidential Attachment A to PGE Response to Staff DR 119.
[71] "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

PGE currently has 716.5 MW of wind generation approved for California RPS standards, located in Oregon and Washington.[72]

Staff has consulted the Annual Summary of GHG Mandatory Reporting released to the public by CARB for the two most recent calendar years available, and discovered that PGE reported an average of 236,404 MT CO2e[73] of "Non-Covered Emissions,"[74] which is equivalent to 552,344 MWh of RECs each year.

Q. Did Staff engage with PGE on this issue?

A. Yes. Taking the 2019 compliance year as an example, Staff learned that as an electricity importer PGE was able to claim an RPS adjustment by listing the RECs to be retired in its annual report to CARB. However, PGE did not retire the RECs, but instead transferred them to a California load serving entity to be retired.

Although not explicitly stated by the Company, Staff expects that this occurs in part due to bundled power sales (including both MWh and RECs) to entities in California. Staff is satisfied that the Company's use of RECs for CARB compliance is not directly related to its EIM operations. Staff does not have an adjustment relating to this issue.

[72] Relates to Biglow Canyon and Tucannon River Wind Farms. Data downloaded from the California Energy Commission on June 16, 2021. Staff/105, Enright/1.

[73] Metric Tonnes of CO2 equivalent.

[74] Staff/105, Enright/2 - 3.

Q. Please summarize Staff's recommendation relating to EIM GHG benefits.

A. Staff recommends updating the Company's calculation of GHG benefits to account for up to three years of historic data, the use of CCOs for four percent of CARB compliance, and the historic proportion of thermal generation being "deemed delivered" to EIM. This results in a total adjustment of ($395,629).[75]

ISSUE 2, PART 3 - FLEX RESERVE TRANSFER BENEFITS

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

A. The diversity of loads and variability of resources in the EIM allows 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.[76]

Q. How has the Company forecasted its flex reserve benefits for 2022?

A. The Company is including its net benefit associated with CAISO's flexible ramping product awards in its 2022 forecast. The forecast is based on the three-year simple average of historical settlement data from 2018 to 2020 and is expected to provide a flex reserve benefit of approximately $0.4 million in 2022.[77] The Company indicated that benefits relating to holding lower reserves

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[75] Note that the total adjustment is not equal to the sum of the three adjustments, as each adjustment affects the other.

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

[77] PGE/100, Vhora-Outama-Batzler/29, lines 13 - 22.

are picked up by its energy transfer benefit model, where the dispatch of generators is modelled, including the dispatch of any freed-up capacity.[78]

Q. Does Staff propose an adjustment related to this issue?

A. No.

ISSUE 2, PART 4 - EIM COSTS

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

A. EIM Grid Management Charges (GMCs) are variable costs that are recovered in the AUT. Forecasted GMCs for 2022 total $1.1 million, and increase NVPC.

Q. How has the Company forecasted its EIM costs for 2022?

A. Similar to the previous filing, the Company has used **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[79]

Q. Is Staff satisfied with this approach?

A. No. Staff investigated the EIM's published GMCs since January 2018[80] and learned that because GMCs are set based on trading volumes in the entire EIM market, GMCs both increase and decrease over time, being refreshed several

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78 UE 377 PGE/100, Seulean-Kim-Batzler/8, footnote 3.

79 Staff/103, Enright/10, Confidential PGE workpaper "#17_2022 GMC Charge Forecast_MFR_04-01-21"

80 Calendar year 2018 was PGE's first full year operating in EIM.

times per year. Staff compared the rates for charge codes incurred by PGE[81,82] in January 2018 to those in effect in January 2021, and found that on the whole, the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

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

A. Yes. Staff recommends that the Company remove the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** from its forecast. This would leave the Company's forecasting methodology unchanged from last year's filing, and result in a $44,770 decrease in NVPC.

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[81] PGE pays charge codes **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

[82] Staff/106, Enright 1 - 4.

ISSUE 2, PART 5 - EIM UPDATE

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

A. The EIM has expanded over the past year with the addition of three new utilities, Los Angeles Department of Water & Power, Public Service Company of New Mexico, NorthWestern Energy, and Turlock Irrigation District. Following this expansion, the EIM footprint now includes portions of Arizona, California, Idaho, Nevada, Oregon, Montana, Utah, Washington, Wyoming, New Mexico, and the Canadian province of British Columbia.

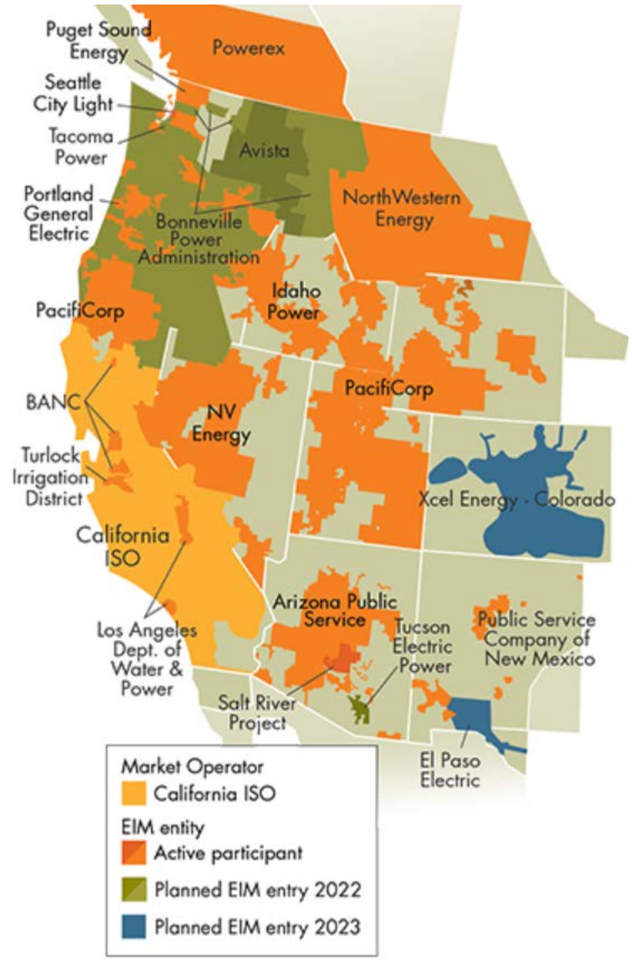

Figure 8 - Map of current and future EIM participants

Q. Is further expansion of the EIM planned?

A. Yes. An additional seven entities have committed to joining the EIM over the next two and a half years, including utilities in Washington, Arizona, Colorado, and New Mexico, along with the

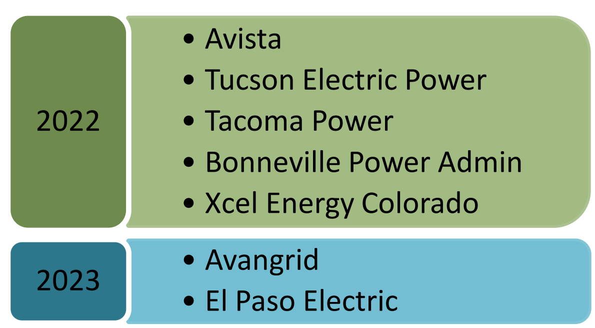

Figure 9 - List of future EIM participants

AvanGrid Renewables Northwest Balancing Authority.[83]

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).[84]

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

A. Yes. Staff's understands that an EDAM is still under consideration but has been delayed by 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, however PGE expects that it will recommence in Fall 2021.[85]

Staff understands that EDAM initiative has been grouped into the following three bundles of topics.

1) Resource sufficiency evaluation, transmission provision, and the distribution of revenues related to congestion and enforcement of transfer constraints.
2) Greenhouse gas accounting, inclusion of ancillary services, implementation of the second phase of the extension of the full network model, and the EDAM administration fee.

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

84 Western Energy Imbalance Market News Release June 16, 2021. https://www.westerneim.com/Documents/NorthWestern-Energy-Joins-the-Western-Energy-Imbalance-Market.pdf

85 Staff/102, Enright/4, PGE Response to Staff DR 73.

3) Price formation, inclusion of convergence bidding, external resource participation, enhancements to market power mitigation, and any additional topics identified through the consideration of the first two bundles.[86]

Staff intends to continue to monitor this issue outside of the current AUT filing.

[86] Staff/102, Enright/4, PGE Response to Staff DR 73.

ISSUE 3. FARADAY REPOWERING PROJECT

Q. Please provide an overview of the Faraday Repowering Project.

A. Units 1-5 of PGE's Faraday hydro facility were constructed in 1907 and a sixth unit (Unit 6) was put in service in 1965. In the Faraday Repowering Project, PGE is removing Faraday Units 1 through 5, upgrading Unit 6, installing two newer high-efficiency turbines (Faraday Units 7 and 8), and replacing the associated structures.[87] The expected online date for the units is in March 2022.[88] The March 2022 expected online date makes this project relevant to the 2022 AUT filing, as it will be the first year in which the Company models the operation of Units 7 and 8 in its forecast of NVPC.

Q. What assumptions has the Company made about Faraday Units 7 and 8 in its forecast of 2022 NVPC?

A. The Company has made assumptions regarding the Faraday hydro project's plant efficiency (H/K factors), estimated online date, generation of Production Tax Credits (PTC), and generation of Renewable Energy Credits (REC).

Q. Please explain how H/K factors are treated for the Faraday units in this filing.

A. H/K factors measure the efficiency of the plant, expressed in KW/cfs (cubic feet per second).[89] So, the higher the H/K factor, the more power the plant can

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87 Staff/102, Enright/5, PGE Response to Staff DR 95.
88 Staff/102, Enright/6, PGE Response to Staff DR 96.
89 The actual output of energy at a hydro generator is determined by the volume of water released (discharge) and the vertical distance the water falls (head). So, a given amount of water falling a given distance will produce a certain amount of energy. The head produces a water pressure, and the greater the head, the greater the pressure to drive turbines. More head or faster flowing water means more power generated.

output given the same amount of water; thus, reflecting the increase in efficiency.[90] The H/K factor of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** used by PGE for the Faraday units in its initial filing was originally set in its 2011 General Rate Case (GRC).[91,92]

When questioned, the Company explained that the exact H/K factors for Units 6 through 8 would not be known until the units are online and operating.[93] The Company also expressed its expectation that the three repowered units will operate more efficiently than the original six units, with an approximate forecasted generation from the Faraday hydroelectric scheme set to increase by 22 percent.[94] This is driven by a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** percent increase in the efficiency of Unit 6, plus a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** percent increase in the efficiency of the facility compared to the original Faraday units 1 through 5.[95] This represents the best available estimates, which were modelled in the Faraday turbine selection study in **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[96]

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90 For instance, water used to generate power at PGE's Round Butte station flows down to the Pelton station. Because of the different H/K factors at each station, different quantities of power will be generated at each station using the same quantity of water. A steady flow of 3000 cfs going through both stations will generate **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** at Round Butte, and **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** at Pelton. Staff/103, Enright/6, PGE Confidential workpaper "#2_PGEHydroStudy_2019GRC-Apr2018"

91 Staff/103, Enright/4, PGE workpaper "^_2022AUTHydroHKFactors"

92 Staff/103, Enright/8, PGE Confidential workpaper "#2022 AUT-00l"

93 Staff/102, Enright/7, PGE Response to Staff DR 98.

94 Staff/102, Enright/8 - 9, PGE Response to Staff DR 99.

95 Staff/102, Enright/10, Confidential Attachment A to PGE Response to Staff DR 99.

96 Staff/102, Enright/8 - 9, PGE Response to Staff DR 99, and Staff/102, Enright/10, Confidential Attachment A to PGE Response to Staff DR 99.

Staff discovery showed that the Company intends to update the H/K factor in its scheduled July filing, following its re-estimation of the values.[97] The Company indicated that if it does not file a GRC for the test year 2022, it intends to leave the Faraday H/K factors provided with direct testimony unchanged.[98]

Q. What is Staff's recommendation regarding the Faraday H/K factors?

A. Staff supports the use of re-estimated H/K factors in this filing given the expected improvements in the efficiency of the units, however it is disappointing that the re-estimated values were not included in the initial filing to allow for them to be examined by Staff and intervenors. Staff recommends that the Company update its Faraday H/K factors to reflect the most recent estimates, regardless of whether it files a 2022 GRC. Staff intends to review the re-estimated H/K factors once provided, and reserves the right to make further recommendations regarding this issue at that time.

Q. Please explain how the Company has dealt with the issue of PTCs earned from the Faraday Repowering Project in this filing, and Staff's recommendation on this issue.

A. The Company has not included the expected value of PTCs in this filing. Staff recommends including the forecasted value of PTCs earned as an offset to 2022 NVPC. Considering an online date in March 2022, Staff estimates that

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97 Staff/102, Enright/7, PGE Response to Staff DR 98.
98 Staff/102, Enright/27 - 28, PGE Response to AWEC DR 008.

this change would decrease NVPC by **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Q. Please explain how the Company has dealt with the issue of RECs earned from the Faraday Repowering Project in this filing, and Staff's recommendation on this issue.

A. Incremental energy delivered from facilities operational before January 1, 1995, is considered RPS-qualifying if that energy is attributable to efficiency upgrades. Expecting that the Faraday Repowering Project would generate RECs due to the increase efficiency of the plant, Staff engaged with PGE on this issue.

Although the Faraday Repowering Project is expected to result in incremental generation, PGE stated that it does not expect that the quantity of RECs generated will differ significantly from historical REC generation[99] given the small scale of the hydro plant. Further, PGE asserted that its self-generated RECs have an accounting value of zero and are not included in the NVPC forecast for that reason.[100]

Staff has no recommended adjustments relating to this issue.

Q. Please detail the Company's assumption regarding the estimated online date of the projects, and Staff's recommendations regarding this issue.

A. The Company has forecasted that both Units 7 and 8 will come online in March 2022. This is a delay from the Company's estimate in its 2021 AUT that Unit 7

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[99] Historic production of RECs from the Faraday units average 5,084 units per annum. Staff/102, Enright/25, Attachment A to PGE Response to Staff DR 122.

[100] Staff/102, Enright/23 - 24, PGE Response to Staff DR 122.

would be on-line in 2021. It is also later than the **[BEGIN CONFIDENTIAL** [redacted] **[END CONFIDENTIAL]** estimated on-line date for both units included in the Company's Guide to Plant Maintenance provided with the initial 2022 AUT filing,[101,102]

Given the previous delays for this project, Staff recommends a one-time modification to Schedule 125 to allow the Company opportunity to update the on-line date for this project at the last possible update. Specifically, Staff recommends modifying Schedule 125 to require the Company to include the following updates in its November filing for the 2022 AUT: an update to the expected online date of Faraday Units 7 and 8, the facility's generation forecast, and PTCs.

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[101] UE 377 CUB/102, Gehrke/1.

[102] Staff/103, Enright/5, PGE Confidential workpaper "#_2022AUTCCartyForcedOutageRate"

ISSUE 4. COLSTRIP, CARTY, AND BEAVER FORCED OUTAGE RATES

Q. Please provide a summary of this issue.

A. In the most recent AUT filing, Docket No. UE 377, AWEC raised concerns about the forced outage rates (FORs) used for both the Colstrip and Carty plants.[103]

Q. How are forced outage rates calculated?

A. In accordance with Commission Order No. 10-414, a plant-specific FOR is calculated for each electric generating resource based on a four-year rolling average of annual FORs. In the event of an outlier FOR (greater than 90 percent or lower than 10 percent) in any of the previous four years, the outlier FOR is replaced with a FOR based on a 20-year rolling average, or the years the plant has been in service if less than 20 years. This substitute FOR is then used in the four-year average. The same process is used to replace an annual FOR if there is an imprudent outage in a year.[104]

ISSUE 4, PART 1 - COLSTRIP

Q. Please explain what issue arose in Docket No. UE 377 relating to the Colstrip FOR.

A. In Docket No. UE 377, AWEC questioned the prudence of extended forced outages that occurred at Colstrip in 2018 due to plant emissions exceeding the Mercury and Air Toxic Standards compliance limits. AWEC recommended that PGE remove the 2018 Colstrip FOR from the four-year rolling average

[103] UE 377 AWEC/100, Kaufman/2 - 7, and 10 - 13.
[104] Order No. 10-414, p. 5.

methodology used by PGE to model the 2021 Colstrip FOR.[105] Ultimately, the parties agreed to a settlement that resolved this issue without resolving the question of whether the 2018 FOR should be replaced with a 20-year FOR.

Q. What methodology has PGE used to calculate the Colstrip FOR in this filing?

A. PGE calculates the Colstrip FOR using the same methodology as in last year's filing.[106]

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

A. Staff recommends that the 2018 Colstrip FOR be removed from the four-year rolling average and replaced by the 20-year rolling average FOR.[107]

<u>ISSUE 4, PART 2 - CARTY</u>

Q. Please explain what issue arose in Docket No. UE 377 relating to the Carty FOR.

A. In Docket No. UE 377, PGE used two years of initial estimates and two years of actual FORs in the four-year rolling average to calculate the 2021 Carty FOR. AWEC raised concerns regarding this Carty FOR modeling due to PGE's inclusion of two years of hypothetical outage rates.[108]

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[105] UE 377 AWEC/100, Kaufman/2 - 7.
[106] PGE workpaper "^_2022AUTColstrip4ForcedOutageRate"
[107] Order No. 10-414, p. 5.
[108] UE 377 AWEC/100, Kaufman/10 - 13.

Q. What methodology has PGE used to calculate the Carty FOR in this filing?

A. PGE calculates the Carty FOR using three full years of actual data, and one year of estimates.[109]

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

A. Staff recommends that PGE use actual historic data to calculate the FOR, and that the Company update the FOR for Carty in its October update. Staff's recommendation would allow for three years and eight months of actual data to be included in the calculation.

ISSUE 4, PART 3 - BEAVER

Q. Please explain Staff's concern in relation to the Beaver FOR.

A. In Docket No. UM 1355, the stipulating parties agreed that the formula for calculating the FOR at Beaver would be revisited in the event that Beaver plant operations changed significantly.[110] As detailed in the Company's opening testimony, the Beaver Modernization Project will upgrade the existing Beaver gas turbine combustion systems from a dual fuel system to a single fuel dry low NOx system. The turbine upgrades will impact Beaver's plant parameters by slightly increasing the plant's capacity and heat rate. The project is expected to begin in spring 2022 and be completed in 2023, with the upgrade of Beaver Unit 6 completed in 2022.[111]

109 Staff/103, Enright/5, PGE Confidential workpaper "#_2022AUTCCartyForcedOutageRate"
110 Order No. 10-414, Appendix A, page 2, part a.
111 PGE/100, Vhora-Outama-Batzler/47 lines 19 - 21 and 48.

Q. What methodology has PGE used to calculate the Beaver FOR in this filing?

A. PGE calculates the Beaver FOR using the same methodology as in last year's filing.[112]

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

A. Staff recommends that the Company address the post-upgrade FOR at Beaver in reply testimony, providing its analysis of the need (or lack of need) for an updated FOR.

Q. Does this conclude your testimony?

A. Yes.

[112] Staff/103, Enright/1 - 2, PGE workpapers "^_2022AUTBeaverUnits1-7ForcedOutageRate" and "^_2022AUTBeaverUnit8ForcedOutageRate"

CASE: UE 391
WITNESS: MOYA ENRIGHT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualifications Statement

June 30, 2021

WITNESS QUALIFICATIONS STATEMENT

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

CASE: UE 391
WITNESS: MOYA ENRIGHT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 102

Exhibits in Support
Of Opening Testimony

June 30, 2021

Confidential Staff Exhibit

“Confidential Attachment A to PGE Response to Staff DR 42”

is filed in electronic format

May 19, 2021

TO: Heather Cohen
Public Utility Commission of Oregon

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC COMPANY
UE 391
PGE Response to OPUC Data Request No. 060
Dated May 5, 2021

Request:

In PGE/100, Vhora – Outama – Baltzer/45 PGE states that the increase of the Confederated Tribes' ownership of the Pelton-Round Butte will increase the 2022 NVPC forecast by $9.3 million.

a. Please provide PGE's calculation of this value in electronic workbook format with all cells and formulas intact. Ensure that all input data is included.
b. Please include a step-by-step narrative of how PGE performed the calculation provided in section a above, including the dollar amounts per step (i.e dollar amount cost for full share, dollar amount value of the energy provided for the Cove Obligations, etc).
c. Please reference all PGE work papers with these steps.

Response:

a. In PGE Exhibit 100, PGE inadvertently misstated the net variable power cost impact associated with the increase in the Confederated Tribes' ownership share from 33.3% to 49.9% at Pelton-Round Butte as $9.3 million. The $9.3 million referenced was based on contracts and forward market price curves as of December 30, 2020, rather than the curve snapshot PGE used when filing its initial 2022 AUT forecast. The actual power cost impact reflected in PGE's initial 2022 NVPC forecast submitted on April 1, 2021 is an increase of $8.9 million, which is based on contracts and forward market price curves as of February 26, 2021.

   Attachment 060-A provides a workpaper reflecting the power cost impact associated with the increase in the Confederated Tribes' ownership of the Pelton-Round Butte hydro facility.

   It is also important to note that the net variable power cost impact associated with the expected change in ownership share is dependent on forward market prices and thus will change with each subsequent MONET forward price curve update.

b. To reflect the NVPC impact associated with the increase in the Confederated Tribes' ownership share, PGE reversed the following inputs in the initial 2022 NVPC forecast, as provided in Attachment 060-A:
    - PGE changed PGE's share from 50.01% in the April 1, 2021 MONET Output to 66.67%, as reflected in PGE's final 2021 NVPC forecast: See worksheet "PC Input", Cell F353. The change in PGE's share impacts the following:
        - Cove Replacement to PPL: see worksheet "PC Input", rows 352-354.
        - Tribes Allocation Agreement costs: see worksheet "PC Input", rows 386-400.
    - PGE reversed the fixed payments amounts reflected in the worksheet "PC Input", Cell H398, to the value modeled in PGE's final 2021 NVPC forecast. For more details regarding variable and fixed costs associated with the Tribes Allocation Agreement, please see April 15 MFRs, Vol 5 - Contracts\Tribes Allocation Agreement.
    - These changes result in a decrease to PGE's initial 2022 initial NVPC forecast as filed on April 1, 2021, of approximately $8.9 million reflected in worksheet "Step Log", cell R6, which essentially reflects the power cost impact from updating PGE's ownership share at Pelton-Round Butte since the model step is increasing PGE's share back to 66.67%, as modeled in PGE's 2021 final NVPC forecast.

c. Please see PGE's April 15 MFRs, Vol 5 - Contracts\Tribes Allocation Agreement. Document "#_2022AUTTribesAllocationAgreement" provides a narrative description of the modeling associated with the Tribes Allocation Agreement, including all the work papers used in support of this modeling, which are provided within the referenced MFR.[1]

Attachment 060-A is protected information subject to Protective Order No. 21-099.

[1] Please note that in the MONET model, costs associated with Tribes Allocation Agreement are modeled separately from the energy modeling for the Pelton-Round Butte facility. The energy generation modeling for the Pelton-Round Butte facility is based on the Northwest Power Pool's PNCA Headwater Benefits Study (HWBS) as provided in the April 15 MFRs, Vol 4 - Hydro\Energy.

May 27, 2021

TO: Moya Enright
Public Utility Commission of Oregon

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC COMPANY
UE 391
PGE Response to OPUC Data Request No. 073
Dated May 13, 2021

Request:

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:

The CAISO has separated the Extended Day-Ahead Market (EDAM) initiative into three bundles of topics. The first bundle includes the resource sufficiency evaluation, transmission provision, and the distribution of revenues related to congestion and enforcement of transfer constraints. The second bundle will address greenhouse gas accounting, inclusion of ancillary services, implementation of the second phase of the extension of the full network model, and the EDAM administration fee. The final bundle will address price formation, inclusion of convergence bidding, external resource participation, enhancements to market power mitigation, and any additional topics identified through the consideration of the first two bundles. The CAISO has proposed this sequence because the development of policy around each bundle is fundamental to development of policy for the subsequent bundles. CAISO presented their Straw Proposal regarding bundle one topics on July 27, 2020, but due to the California heat events in 2020, stakeholder priorities have shifted to the CAISO's Market Enhancements for Summer 2021 Readiness. Although a schedule for when EDAM is expected to resume has yet to be determined, it is anticipated that the EDAM stakeholder process will recommence in fall 2021.

June 8, 2021

TO: Moya Enright
Public Utility Commission of Oregon

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC COMPANY
UE 391
PGE Response to OPUC Data Request No. 095
Dated May 25, 2021

Request:

Please indicate the date on which the Faraday Repowering Project is expected to begin. If this is an estimate, **please consider this an ongoing request for an updated response if the estimated date changes**.

Response:

The Construction Notice to Proceed for the Faraday Repowering Project was issued on May 21, 2019 and major construction activities started in July 2019.

June 8, 2021

TO: Moya Enright
Public Utility Commission of Oregon

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC COMPANY
UE 391
PGE Response to OPUC Data Request No. 096
Dated May 25, 2021

Request:

Please indicate the date on which the Faraday Repowering Project is expected to be complete. If this is an estimate, **please consider this an ongoing request for an updated response if the estimated date changes**.

Response:

The current project schedule provides for synchronization to grid to be achieved in March 2022.

June 8, 2021

TO: Moya Enright
Public Utility Commission of Oregon

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC COMPANY
UE 391
PGE Response to OPUC Data Request No. 098
Dated May 25, 2021

Request:

Please indicate the filing in which the Company expects to update the H/K coefficients for the new units. If this is an estimate, **please consider this an ongoing request for an updated response if the expected filing changes**.

Response:

Confirmed H/K coefficients will only be available after the Faraday Repowering project is finalized and Faraday Units 6 through 8 are online and operating.

For the 2022 AUT filing, PGE is currently planning to adjust the average energy production for Faraday in the July 15, 2021 MONET update, to reflect the expected total annual generation from the Faraday Repowering Project. See PGE's response to OPUC Data Request No. 099 for additional detail regarding the Faraday Repowering Project expected annual generation.

June 8, 2021

TO: Moya Enright
Public Utility Commission of Oregon

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC COMPANY
UE 391
PGE Response to OPUC Data Request No. 099
Dated May 25, 2021

Request:

Regarding the H/K coefficients of the new units:

a. Please provide the confirmed the H/K coefficient to Staff for the new units as soon as this is known. **Please consider this an ongoing request.**

b. Please provide the expected H/K coefficients of the new units, as expressed in the planning documents, turbine specification, or other equivalent document.

c. Please indicate PGE's expectation regarding whether the expected H/K coefficients shown in response to section (a) will be achieved. Please provide supporting evidence for this response. **Please consider this an ongoing request for an updated response if PGE's expectation changes**.

Response:

a. PGE will have confirmed H/K coefficients when the Faraday Repowering Project is completed and Units 6, 7, and 8 are online and operating.

b. Project planning documents did not estimate an H/K coefficient for the new Faraday Units 7 and 8. As part of the project planning, Faraday Units 7 and 8 configurations were selected by estimating capacity and generation increases for different unit configurations. The method for selecting the powerhouse configuration was:

   - PGE compared different turbine types and configurations suitable for head and flow conditions
   - Compared different unit configurations to optimize plant capacity and generation
   - Estimated a simulated historic generation year
   - Estimated new plant capacity and annual output based on the simulated historic generation year
   - Due to the new configuration of the powerhouse and the higher turbine efficiencies with Units 7 and 8 at lower flows, the available water will be

generated more efficiently than in historical operations. With the new units in place, Unit 6 is able to operate at a more efficient point on the turbine efficiency curve.

Based on project planning documents, the Faraday Repowering Project is expected to result in a total 178,649 MWh estimated total annual generation, or an estimated net annual generation increase of approximately 32,490 MWh compared to historical 5-year actual generation between 2012 and 2016.

Attachment 099-A provides the Faraday Turbine Selection Study Report. Please see total Faraday hydro facility historic generation prior to the Faraday Repowering Project in Table 2-5 (see Unit 6 in Table 2-4 and Units 1-5 in Table 2-3). The expected Faraday hydro facility generation when the Faraday Repowering Project is completed is provided in Table 2-19 (see Unit 6 in Table 2-18 and the two new Units 7 and 8 in Table 2-17).

c. PGE expects that the estimated total annual generation described in part b. will be achieved. This information was the basis for selecting the configuration for Units 7 and 8. At this time there is no additional information that would lead PGE to expect significant changes to this estimate. Should PGE identify that any adjustments to the estimated total annual generation are necessary, those will be incorporated in the MONET modeling.

Attachment 099-A is protected information subject to Protective Order No. 21-099.

Confidential Staff Exhibit

"Confidential Attachment A to PGE Response to Staff DR 99"

is filed in electronic format

Confidential Staff Exhibit

“Confidential Attachment A to PGE Response to Staff DR 102”

is filed in electronic format

June 11, 2021

TO: Moya Enright
Public Utility Commission of Oregon

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC COMPANY
UE 391
PGE Response to OPUC Data Request No. 114
Dated May 28, 2021

Request:

Regarding the outages described on PGE/100, Vhora–Outama–Batzler/41–42:

a. Please provide the forecasted start and end date of each of the outages described in the Company's testimony. **This is an ongoing request from Staff to provide an updated response to this DR as soon as practicable after any changes in the planned outage dates**.

b. Please confirm that the four week outage of unit 1 at Round Butte described on lines 1 - 3 is in addition to the six week outage described on lines 4 - 10.

c. If yes to section (a), Staff is interested in learning whether PGE has attempted to conduct the governor/exciter upgrade on unit 1 simultaneously with the upgrade of the station service 480v switchgear. Please provide a narrative response to this section, including an overview of the Company's considerations, the Company's efforts, any obstacles encountered, and the ultimate result.

d. With reference to the Company's response to section (c), please quantify any additional costs associated with conducting both outages simultaneously, providing a comparison of these costs versus the value of lost generation for each additional day of outage.

e. Please indicate whether the Pelton unit 2 outage, and the Round Butte outages will be conducted simultaneously.

f. If no to section (e), Staff is interested in learning whether PGE has attempted to conduct the Round Butte outages simultaneously with Pelton unit 2 outage. Please provide a narrative response to this section, including an overview of the Company's considerations, the Company's efforts, any obstacles encountered, and the ultimate result.

g. With reference to the Company's response to section (f), please quantify any additional costs associated with conducting both outages simultaneously, providing a comparison of these costs versus the value of lost generation for each additional day of outage.

Response:

a. Attachment 114-A provides the most current schedule for the Pelton and Round Butte maintenance outages referenced by Staff in this data request. The maintenance outage schedule may be further adjusted as scope, engineering, and budgets are better defined. Please note that the governor/exciter upgrade mentioned in PGE Exhibit 100 at Round Butte is on Unit 2, not Unit 1. Also, the scope for the Pelton Unit 2 maintenance outage has been reduced to do exciter/governor work only based on inspections made in early 2021. The generator and rotor rewind have been moved to 2023.
b. PGE confirms that Staff's understanding is correct. Please refer to Attachment 114-A for the most recent maintenance outage schedule.
c. The governor/exciter upgrade for Round Butte Unit 2 requires station power supply to support the outage. At this time, the current project design for the 480 V electrical system replacement will disconnect the station service power supply for the entirety of the outage. PGE anticipates renting emergency generators to power critical loads at the plant and does not anticipate adequate capacity to support the equipment required to perform the annual inspections and repairs. Given the loss of station power supply required for the switchgear work, these outages cannot be overlapped.
d. This option has not been assessed because it is not currently possible to overlap the outages as explained in c.
e. No. Please see Attachment 114-A.
f. PGE does not normally overlap Pelton and Round Butte major outages as the plants share maintenance and operations personnel and resources. Additionally, with the Round Butte units out of service, PGE expects having all three units available at Pelton will mitigate any spill that might be required at Pelton due to the volume of flow spilling from Round Butte. With Round Butte entirely out of service, Pelton effectively operates as a "run of river," e.g. non-dispatchable, flow through power house. By overlapping the outages, Pelton would be reduced to two available units during the Round Butte entire plant outage. If a forced event occurred on one of the remaining in-service Pelton units, the river flow would have to be processed through a single Pelton unit, possibly requiring spilling at Pelton dam. It would also require an immediate labor shuffle to address the forced event, putting the outage schedule for both planned outages at risk.
g. PGE objects to this request on the basis that is requires new analysis. Without waiving and notwithstanding this objection, PGE responds as follows:
   PGE has not done the cost analysis Staff requests.
   However, from a maintenance resource management and a risk management standpoint, separating the outages at Pelton and Round Butte is the appropriate approach. Please see response to part f. for additional detail.

Attachment 114-A is protected information subject to Protective Order No. 21-099.

Confidential Staff Exhibit

"Confidential Attachment A to PGE Response to Staff DR 114"

is filed in electronic format

June 11, 2021

TO: Moya Enright
Public Utility Commission of Oregon

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC COMPANY
UE 391
PGE Response to OPUC Data Request No. 115
Dated May 28, 2021

Request:

Has the Company engaged with the owners or operators of upstream storage or power generation, regarding water management during the outages?

a. Specifically, has the Company investigated contracting with other parties to manage flows in a way that minimizes the value of lost generation during the outages (reduce flows during outages, increases flows prior to and following outages). Please provide a narrative response to this section, including an overview of the Company's considerations, the Company's efforts, any obstacles encountered, and the ultimate result.
b. With reference to the Company's response to section (a), please quantify any costs associated with such contracting, providing a comparison of these costs versus the value of lost generation for each additional day of outage.

Response:

a. PGE has not "coordinated" with the owners/operators for flow management. Given the uncertainty in duration and scope of the outages at Pelton-Round Butte, it would be premature to reach out this early in the planning process.
b. PGE objects to this request on the basis that it calls for new analysis. Without waiving and notwithstanding this objection PGE responds as follows:

   PGE does not have data to perform the comparison requested.

June 11, 2021

TO: Moya Enright
Public Utility Commission of Oregon

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC COMPANY
UE 391
PGE Response to OPUC Data Request No. 116
Dated May 28, 2021

Request:

Staff notes that the Company expects the Confederated Tribes of the Warm Springs Reservation of Oregon (Tribes) to exercise its option to increase its stake in the PRB project (Option).

a. PGE/100, Vhora–Outama–Batzler/44 indicates that "The PRB maintenance outage is causing an increase of approximately $3.6 million in the 2022 NVPC". Please confirm that the $3.6 million value was calculated including the assumption that the Tribes would exercise its Option.

b. If yes to section (a) above, please indicate the dollar value of the increase in NVPC attributable to the PRB outage, in the event that the Tribes does not exercise the Option.

c. If no to section (a) above, please indicate the dollar value of the increase in NVPC attributable to the PRB outage, in the event that the Tribes does exercise the Option.

d. On what date does the Company expect to finalize its agreement with the Tribes regarding the exercise of the Option? **This is an ongoing request from Staff to provide an updated response to this DR as soon as practicable after any changes in the date**.

e. Please provide a narrative explanation of the Company's engagement with the Tribes to date regarding its exercise of the Option. Please include the dates and details of any recent communications.

Response:

a. Yes, PGE confirms that Staff's understanding is correct. However, in PGE Exhibit 100, PGE inadvertently misstated the net variable power cost impact associated with the Pelton-Round Butte maintenance outages as $3.6 million. The $3.6 million referenced was partially based on contracts and forward market price curves as of December 30, 2020, rather than the curve snapshot PGE used when filing its initial 2022 AUT forecast. The actual power cost impact reflected in PGE's initial 2022 NVPC forecast submitted on April 1, 2021 is an increase of $3.1 million, which is based on contracts and forward market price curves as of February 26, 2021.

b. Should the Confederated Tribes of the Warm Springs Reservation of Oregon (Tribes) choose not to give notice to exercise their purchase option, the net variable power cost impact associated with the Pelton-Round Butte maintenance outages would be an increase of approximately $3.7 million.

   It is also important to note that the net variable power cost impact associated with the Pelton-Round Butte maintenance outages described in PGE Exhibit 100 is dependent on forward market prices and thus will change with each subsequent MONET forward price curve update.

c. See part a.

d. PGE objects to this request on the basis that it calls for speculation. Without waiving and notwithstanding this objection, PGE responds as follows:

   PGE expects the Tribes to deliver written notice to exercise their purchase option no later than July 1, 2021, which is the notice deadline as specified in the Long-Term Global Settlement and Compensation Agreement between the Tribes, The United States Department of Interior, and PGE (LTGSA), that was executed in April of 2000. Attachment 116-A provides the LTGSA with the Tribes' purchasing option exercise notice located at page 27 of the pdf document.

e. See Attachment 116-B.

Attachments 116-A and 116-B are protected information subject to Protective Order No. 21-099.

Confidential Staff Exhibit

**"Confidential Attachment A to
PGE Response to Staff DR 117"**

is filed in electronic format

Confidential Staff Exhibit

"Confidential Attachment A to PGE Response to Staff DR 119"

is filed in electronic format

June 22, 2021

TO: Moya Enright
Public Utility Commission of Oregon

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC COMPANY
UE 391
PGE Response to OPUC Confidential Data Request No. 121
Dated June 4, 2021

Request:

With regard to Company's response to DR 67.

a. The data provided in Confidential Attachment C to DR 67 suggests that PGE used **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** percent CCOs for CARB compliance in 2018, and **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** percent CCOs for compliance in 2019. Please confirm or deny Staff's understanding of this data.

b. If confirmed at section (a), please explain how this was possible, considering the CCO usage limits shown in response to Staff DR 67, section (d).

c. If denied at section (a), please provide clarification on the significance of the values in Confidential Attachment C to DR 67.

d. If denied at section (a), please provide the following information in electronic workbook format with all cells and formulas intact.

   i. Total CCAs used for CARB compliance in 2018, 2019, 2020.

   ii. Total CCOs used for CARB compliance in 2018, 2019, 2020.

e. In Confidential Attachment C to DR 67 Tab "Weighted Rate and Benefit," Cell P18, the company indicates that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Please indicate why this value differs from the CCO usage limits shown in response to Staff DR 67, section (d).

f. Does the Company use CCOs sourced from projects that do provide direct environmental benefits in the state of California for its CARB compliance? If yes, please provide a breakdown of the data requested in section (d), parts (i) and (ii), separately showing the proportion of CCOs used for compliance that:

   i. Do provide direct environmental benefits in the state of California, and

   ii. Do not provide direct environmental benefits in the state of California.

g. If no to section (f), please indicate whether the Company has purchased, attempted to purchase, or investigated its options to purchase CCOs sourced from projects that do provide direct environmental benefits in the state of California. Please provide a narrative response, including specific examples, and providing supporting evidence.

Response:

PGE does not consider the OPUC Data Request No 121 to be confidential. As such, PGE is providing this response as public information.

a. PGE does not confirm OPUC Staff's understanding of the data provided in PGE's response to OPUC Data Request No. 067, Attachment 067-C. Attachment 121-A provides the percentage CCOs used for compliance with CARB in 2018, 2019, and an estimated CCO quantity to be used for 2020 compliance. Per CARB's cap and trade regulation, offset credits can be surrendered for up to 8% of the compliance obligation through the 2020 compliance year (end of the 3rd compliance period). Please note that PGE's CARB compliance obligation for 2020 is preliminary and subject to third party verification and the deadline for surrendering compliance instruments is November 1, 2021.
b. See part a.
c. The values in Attachment 067-C provide CCOs and CCAs surrendered for CARB compliance in 2018 and 2019. Please note that PGE inadvertently provided in Attachment 067-C an incorrect number of CCAs that were used for compliance with 2019 CARB obligation. PGE is providing the correct number of CCAs that were used for compliance with 2019 CARB obligation in Attachment 121-A. Also note, as allowed by the CARB cap and trade regulation, PGE's annual compliance obligation is 30 percent of the reported emissions of the previous year. And at the end of a compliance period, the compliance obligation is the sum of the reported emissions during a compliance period minus the instruments surrendered as part of the annual compliance obligation.
d. See part a.
e. In accordance with the CARB cap and trade regulation, for emissions with a compliance obligation between January 1, 2021 and December 31, 2030, the offset usage limits is decreased from the current limit of 8%. Between January 1, 2021 to December 31, 2025, the offset usage limit is 4%; and from January 1, 2026 to December 31, 2030, the offset usage limit is 6%. In addition, starting on January 1, 2021, no more than one-half of this quantitative usage limit may be sourced from projects that do not provide direct environmental benefits in the state. Please see PGE's response to OPUC Data Request No. 067, Attachment 067-F, Subarticle 7, section 95854(e) at page 137. PGE does not currently have CCOs from projects that provide direct environmental benefits in the state of California.
f. See part e.
g. PGE is currently investigating options to exchange CCOs in its inventories with CCOs sourced from projects that provide direct environmental benefits in the state of California. However, to date, PGE does not have a firm agreement for such exchange.

Attachment 121-A is protected information subject to Protective Order No. 21-099.

Confidential Staff Exhibit

“Confidential Attachment A to PGE Response to Staff DR 121”

is filed in electronic format

June 22, 2021

TO: Moya Enright
Public Utility Commission of Oregon

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC COMPANY
UE 391
PGE Response to OPUC Data Request No. 122
Dated June 8, 2021

Request:

Regarding the Faraday Repowering Project.

a. Will the Company earn Renewable Energy Credits (REC) as a result of this project?
b. If yes to section (a), please detail
   i. the quantity of RECs that will be received
   ii. the timeframe over which the Company will receive the RECs
   iii. the estimated value of the RECs (providing supporting documentation) in electronic workbook format with all cells and formulas intact.
c. If yes to section (a), please indicate whether the value of the RECs is reflected in the current filing. If it is not reflected in the current filing, please provide an explanation of this.

Response:

a. Efficiency upgrades made on or after January 1, 1995 at the Faraday hydro plant are expected to continue to generate RECs, including the Faraday Repowering Project after finalization.
b.
   i. Although the Faraday Repowering Project is expected to result in incremental generation as described in PGE's response to OPUC Data Request No. 96, PGE does not expect that the quantity of RECs generated will differ significantly from historical REC generation given the small scale of the hydro plant. Attachment 122-A provides historical RECs generated as a result of efficiency upgrades at the Faraday hydro facility as reported in PGE's 2020 Renewable Portfolio Standard Compliance Report submitted on June 1, 2021.
   ii. Assuming no changes in policy concerning REC accounting or qualifying renewable electricity, PGE expects that Faraday will continue to generate RECs f.
   iii. All PGE self-generated RECs have an accounting value of zero.

c. PGE does not include Faraday generated RECs or other PGE self-generated RECs in the NVPC forecast because the accounting value of these RECs is zero.

Staff Exhibit

"Attachment A to PGE Response to Staff DR 122"

is filed in electronic format

Q. Please describe PGE's forecast for GHG benefit in its 2022 NVPC forecast.

A. PGE's forecast for GHG benefit depends on 2020 actual results and the Intercontinental Exchange (ICE) forward price curve for the 2022 California Carbon Allowance. The forecast steps include:

1. Use GHG award price data ($/MWh) and 2020 GHG allowance prices ($/mTCO2[1]) to calculate a weighted implied emission factor (mTCO2/MWh).
2. Using the weighted implied emission factor, apply the ICE forward price curve for the 2022 California Carbon Allowance (ICE product code CB0)~~, adjusted to include California Carbon Offsets (CCOs) used by PGE to comply with California Air Resource Board (CARB) requirements,~~ to the implied emission factor to calculate a GHG Award Price ($/MWh).
3. Multiply the calculated GHG Award Price ($/MWh) by PGE's 2020 award quantities[2] to create a GHG revenue forecast. This revenue is reduced by a forecast of GHG compliance costs where applicable (i.e., thermal resources assumed to sell GHG in 2022). The price used to calculate GHG compliance cost is adjusted to include California Carbon Offsets (CCOs) used by PGE to comply with California Air Resource Board (CARB) requirements.

[1] Metric tons of carbon dioxide.
[2] PGE does revise the 2020 award quantity associated with the Pelton Round Butte facility to account for the full Round Butte outage planned for 2022.

May 24, 2021

TO: Jesse O. Gorsuch
Alliance of Western Energy Consumers

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC COMPANY
UE 391
PGE Response to AWEC Data Request No. 008
Dated May 10, 2021

Request:

Please refer to PGE / 100, Vhora – Outama – Batzler / 9 at lines 14 to 18.

a. When does PGE expect to file its general rate case?

b. Which of the model enhancements itemized on page 8 does PGE intend to withdraw if PGE decides a general rate case filing is not needed?

Response:

a. See Attachment 008-A.

b. Not all the items listed in Exhibit 100, pages 8-9 are model enhancements. Should PGE decide not to file a 2022 general rate case, PGE would withdraw the following model enhancements:

- Lydia Hourly Price Shaping Model Update;
- Gas Storage Optimization Enhancements;
    i. Please note that the Gas Storage Optimization refinements described in PGE Exhibit 100, page 32, lines 11-23 and page 33, lines 1-9 are not modeling enhancements. PGE rather applied refinements and corrections to the gas storage optimization model to ensure alignment with PGE's actual operations and fuel supply capabilities. For the cost impact associated with these refinements please see the initial model step log submitted with PGE's April 1 MFRs, items Ref-01[#] through Ref-05[#].
- Pacific Northwest Coordination Agreement Study;
    i. PGE did not include the impact of this model enhancement in the initial filing due to an issue PGE uncovered during the validation of the 2019-2020 Headwater Benefits Study. For more details, see PGE Exhibit 100, Section F.2. Should PGE decide not to file a general rate case, PGE would

not make any modeling changes related to the Pacific Northwest Coordination Agreement Study.

- Beaver Plant Upgrade; and
- Faraday Hydro Coefficient Update.

In addition to the modeling enhancements mentioned above, PGE would also withdraw the enhancements applied to the thermal plant parameters included in the initial model step log, Steps 00g through 00k.

Attachment 008-A is protected information subject to Protective Order No. 21-099.

CASE: UE 391
WITNESS: MOYA ENRIGHT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 103

Exhibits in Support
Of Opening Testimony

June 30, 2021

Staff Exhibit

“PGE workpaper ^_2022AUTBeaverUnits1-7ForcedOutageRate”

is filed in electronic format

Staff Exhibit

“PGE workpaper ^_2022AUTBeaverUnit8ForcedOutageRate”

is filed in electronic format

Staff Exhibit

"PGE workpaper ^_2022AUTColstrip4ForcedOutageRate"

is filed in electronic format

Staff Exhibit

“PGE workpaper ^_2022AUTHydroHKFactors”

is filed in electronic format

Confidential Staff Exhibit

“Confidential PGE workpaper #_2022AUTCCartyForcedOutageRate”

is filed in electronic format

Confidential Staff Exhibit

“Confidential PGE workpaper #2_PGEHydroStudy_2019GRC-Apr2018”

is filed in electronic format

Confidential Staff Exhibit

“Confidential PGE workpaper #14GHG_workpaper_MFR_4-01-21 Filing”

is filed in electronic format

Confidential Staff Exhibit

“Confidential PGE workpaper #2022 AUT-00l”

is filed in electronic format

Confidential Staff Exhibit

"Confidential PGE workpaper #Copy of peltonhoverk_2009GRCFeb"

is filed in electronic format

Confidential Staff Exhibit

**“Confidential PGE workpaper
#17_2022 GMC Charge Forecast_MFR_04-01-21”**

is filed in electronic format

CASE: UE 391
WITNESS: MOYA ENRIGHT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 104

Exhibits in Support
Of Opening Testimony

June 30, 2021

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 391
WITNESS: MOYA ENRIGHT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 105

Exhibits in Support
Of Opening Testimony

June 30, 2021

RPSID	RPSID Suffix	Facility Name	Facility City	Facility State	Nameplate Capacity	Technology	Organization Name	Facility Owner	Certification Status
60993	A	Biglow Canyon Wind Farm Phase 1	Wasco	Oregon	125.4	Wind	CEC RPS Archives	Portland General Electric Company	Approved
63055	A	Biglow Canyon Wind Farm Phase 2	Wasco	Oregon	163.3	Wind	CEC RPS Archives	Portland General Electric Company	Approved
63056	A	Biglow Canyon Wind Farm Phase 3	Wasco	Oregon	161	Wind	CEC RPS Archives	Portland General Electric Company	Approved
63027	A	Tucannon River Wind Farm	Dayton	Washington	266.8	Wind	CEC RPS Archives	Portland General Electric Company	Approved

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

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	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 391
WITNESS: MOYA ENRIGHT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 106

Exhibits in Support
Of Opening Testimony

June 30, 2021

California ISO

2021 GMC Rates and Other Fees

Charge Code	Charge/ Fee Name	Effective 1/1/21*	Billing Units
GMC Rates and Fees			
4560	Market Services Charge	$ 0.1485	MWh
4561	System Operations Charge	$ 0.2043	MWh
4562	CRR Services Charge	$ 0.0048	MWh
4515	Bid Segment Fee	$ 0.0050	Per bid segment
4512	Inter SC Trade Fee	$ 1.0000	Per Inter SC Trade
4575	SCID Monthly Fee	$ 1,500	Per month
4563	TOR Charge	$ 0.1800	Minimum of supply or demand TOR MWh
4516	CRR Bid Fee	$ 1.0000	Number of nominations and bids
Other Rates, Charges and Fees			
N/A	Schedule Coordinator Application Fee	$ 7,500	Per application
N/A	CRR Application Fee	$ 5,000	Per application
701	EIR Forecast Fee**	$ 0.1000	MWh
4564	EIM Market Services Charge	$ 0.0936	MWh
4564	EIM System Operations Charge	$ 0.1022	MWh
5701	RC Service Rate	$ 0.0278	MWh
5801	HANA Setup Fee	$ 35,000	One time setup fee (billed over 3 years)
	HANA Annual Administrative Charge	$ 45,000	Annual flat charge
	HANA Study User Subscriptions		See the RC West portal for HANA terms, conditions, and subscription rates.

*2021 rates effective 1/1/21 were approved by the CAISO Board of Governors on December 17, 2020.

**For Forecast Fee, which was approved 2/9/03, see Settlement BPM - Main body document Attachment B at:
https://bpmcm.caiso.com/Pages/SnBBPMDetails.aspx?BPM=Settlements%20and%20Billing

California ISO

2020 GMC Rates and Other Fees

Charge Code	Charge/ Fee Name	Effective 1/1/20*	Effective 6/1/20	Effective 10/1/20	Billing Units
GMC Rates and Fees					
4560	Market Services Charge	$ 0.0994	$ 0.1044	$ 0.0994	MWh
4561	System Operations Charge	$ 0.2788	$ 0.2938	$ 0.2788	MWh
4562	CRR Services Charge	$ 0.0078	$ 0.0078	$ 0.0078	MWh
4515	Bid Segment Fee	$ 0.0050	$ 0.0050	$ 0.0050	per bid segment
4512	Inter SC Trade Fee	$ 1.0000	$ 1.0000	$ 1.0000	per Inter SC Trade
4575	SCID Monthly Fee	$ 1,000	$ 1,000	$ 1,000	per month
4563	TOR Charge	$ 0.2400	$ 0.2400	$ 0.2400	minimum of supply or demand TOR MWh
4516	CRR Bid Fee	$ 1.0000	$ 1.0000	$ 1.0000	number of nominations and bids
Other Rates, Charges and Fees					
N/A	Schedule Coordinator Application Fee	$ 5,000	$ 5,000	$ 5,000	per application
N/A	CRR Application Fee**	$ 1,000	$ 1,000	$ 1,000	per application
701	EIR Forecast Fee	$ 0.1000	$ 0.1000	$ 0.1000	MWh
4564	EIM Market Services Charge	$ 0.0785	$ 0.0825	$ 0.0785	MWh
4564	EIM System Operations Charge	$ 0.1087	$ 0.1146	$ 0.1087	MWh
5701	RC Service Charge	$ 0.0278	$ 0.0278	$ 0.0278	MWh
5801	HANA Setup Fee	$ 35,000	$ 35,000	$ 35,000	one time setup fee (billed over 3 years)
	HANA Annual Administrative Charge	$ 45,000	$ 45,000	$ 45,000	annual flat charge
	HANA Study User Subscriptions				****amount available on RC West portal

*2020 rates effective 1/1/20 were approved by the CAISO Board of Governors on December 19, 2019.

**CRR application fee is $1,000 for applicants who are not already scheduling coordinators.

See rate calculations at:
http://www.caiso.com/informed/Pages/StakeholderProcesses/Budget-GridManagementCharge.aspx

For Forecast Fee, which was approved 2/9/03, see Settlement BPM - Main body document Attachment B at:
https://bpmcm.caiso.com/Pages/SnBBPMDetails.aspx?BPM=Settlements%20and%20Billing

California ISO

2019 GMC Rates and Other Fees

Charge Code	Charge/ Fee Name	Effective 1/1/19*	Effective 5/1/19	Effective 7/1/19	Effective 10/1/19	Effective 11/1/19	Billing Units
GMC Rates and Fees							
4560	Market Services Charge	$ 0.1065	$ 0.1065	$ 0.1065	$ 0.1065	$ 0.1065	MWh
4561	System Operations Charge	$ 0.2797	$ 0.2797	$ 0.2797	$ 0.2797	$ 0.2797	MWh
4562	CRR Services Charge	$ 0.0050	$ 0.0100	$ 0.0100	$ 0.0100	$ 0.0100	MWh
4515	Bid Segment Fee	$ 0.0050	$ 0.0050	$ 0.0050	$ 0.0050	$ 0.0050	per bid segment
4512	Inter SC Trade Fee	$ 1.0000	$ 1.0000	$ 1.0000	$ 1.0000	$ 1.0000	per Inter SC Trade
4575	SCID Monthly Fee	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	per month
4563	TOR Charge	$ 0.2400	$ 0.2400	$ 0.2400	$ 0.2400	$ 0.2400	minimum of supply or demand TOR MWh
4516	CRR Bid Fee	$ 1.0000	$ 1.0000	$ 1.0000	$ 1.0000	$ 1.0000	number of nominations and bids
Other Rates, Charges and Fees							
N/A	Schedule Coordinator Application Fee	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	per application
N/A	CRR Application Fee**	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	per application
701	EIR Forecast Fee	$ 0.1000	$ 0.1000	$ 0.1000	$ 0.1000	$ 0.1000	MWh
4564	EIM Market Services Charge	$ 0.0841	$ 0.0841	$ 0.0841	$ 0.0841	$ 0.0841	MWh
4564	EIM System Operations Charge	$ 0.1091	$ 0.1091	$ 0.1091	$ 0.1091	$ 0.1091	MWh
5701	RC Service Charge***			$ 0.0134	$ 0.0134	$ 0.0270	MWh
5801	HANA Setup Fee				$ 35,000	$ 35,000	one time setup fee (billed over 3 years)
	HANA Annual Administrative Charge				$ 45,000	$ 45,000	annual flat charge
	HANA Study User Subscriptions				****	****	****amount available on RC West portal

*2019 rates effective 1/1/19 were approved by the CAISO Board of Governors on December 13, 2018.

**CRR application fee is $1,000 for applicants who are not already scheduling coordinators.

***There are two RC rates for 2019. The first rate will be effective July 1, 2019 through October 31, 2019 and applicable to entities that onboarded July 1, 2019. The second rate will be effective November 1, 2019 through December 31, 2019 and applicable to all entities that are taking RC services during the period of November 1, 2019 through December 31, 2019.

The RC Service Charge for the period of January 2020 through December 2020 will be posted in December 2019. The 2019 prorated charges and the 2020 annual charges will be invoiced in Jan. 2020.

See rate calculations at:
http://www.caiso.com/informed/Pages/StakeholderProcesses/Budget-GridManagementCharge.aspx

For Forecast Fee, which was approved 2/9/03, see Settlement BPM - Main body document Attachment B at:
https://bpmcm.caiso.com/Pages/SnBBPMDetails.aspx?BPM=Settlements%20and%20Billing

California ISO

2018 GMC Rates and Administrative Fees

Charge Code	Charge/ Fee Name	Rate effective 1/1/18	Rate effective 8/1/18	Billing Units
4560	Market Services Charge	$ 0.1056	$ 0.1100	MWh
4561	System Operations Charge	$ 0.2814	$ 0.2964	MWh
4562	CRR Services Charge	$ 0.0038	$ 0.0038	MWh
4515	Bid Segment Fee	$ 0.0050	$ 0.0050	per bid segment
4512	Inter SC Trade Fee	$ 1.0000	$ 1.0000	per Inter SC Trade
4575	SCID Monthly Fee	$ 1,000	$ 1,000	per month
4563	TOR Charge	$ 0.2400	$ 0.2400	minimum of supply or demand TOR MWh
4516	CRR Bid Fee	$ 1.0000	$ 1.0000	number of nominations and bids
Other fees included in miscellaneous revenue				
4564	EIM Market Services Charge	$ 0.0834	$ 0.0869	MWh
4564	EIM System Operations Charge	$ 0.1097	$ 0.1156	MWh
701	EIR Forecast Fee	$ 0.1000	$ 0.1000	MWh

Scheduling Coordinators: The scheduling coordinator application fee is $5,000.
CRR participants: The CRR application fee is $1,000 for applicants who are not already scheduling coordinators.
2018 rates are as approved by the CAISO Board of Governors on December 14, 2017.

See rate calculations at: *http://www.caiso.com/informed/Pages/StakeholderProcesses/GridManagementChargeBudgetProcesses.aspx*

For Forecast Fee rate which was approved 2/9/03 see Settlement BPM - Main body document Attachment B at:
http://bpmcm.caiso.com/Pages/SnBBPMDetails.aspx?BPM=Settlements%20and%20Billing

CASE: UE 391
WITNESS: HEATHER COHEN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 200

Opening Testimony

June 30, 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 & Audit section of the Public Utility Commission of Oregon (Commission or OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

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

Q. What is the purpose of your testimony?

A. I discuss the Portland General Electric's (PGE or Company) 2022 AUT filing and Staff's review of, and recommended Commission actions regarding issues related to: Wholesale Transactions, Lydia 2.0, and the Pelton Round Butte Tribal Ownership Change.

Q. Have you prepared any exhibits for this docket?

A. Yes. I prepared the following Staff Exhibits:

- Staff/201: Witness Qualification Statement.
- Staff/202: PGE's Responses to Staff DRs 60 and 134.
- Staff/203: PGE's Confidential Responses to Staff DRs 42, Attachment A (electronic spreadsheet), 61 Attachment B, 89 Attachment A (electronic spreadsheet).
- Staff/204: Media Related to Trading Losses.

Q. How is your testimony organized?

A. My testimony is organized as follows:

<u>ISSUE 1. WHOLESALE TRANSACTIONS</u>

Q. How does PGE transact power?

A. The Company purchases and sells electricity largely through bi-lateral agreements and also by participating in the California System Independent Operator's (CAISO) western Energy Imbalance Market (EIM) which allows for load balancing with other western EIM participants in five-minute intervals.[1] As illustrated in confidential Figure 1 below, PGE has consistently **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

<u>FIGURE 1. PGE TRANSACTIONS MWH AND $S, 2016-2020</u>[3]

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. How do purchases and sales in the 2022 AUT compare to those in the 2021 AUT?

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[1] PGE's 2020 Annual Report, page 10. https://investors.portlandgeneral.com/static-files/1e2f2ecd-9741-496b-b275-31bc2df75174

[2] Staff/203, PGE's Confidential Response to Staff DR 89, Attachment A (electronic spreadsheet).

[3] With clarification from PGE, Staff extracted data related to PPAs and QFs that were originally sited in the PGE worksheet under "PGEM/Power/Structuring" and "PGEM/Power/Term."

A. In this AUT, PGE forecasts it will purchase **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. As compared to the final forecast for the 2021 AUT, PGE forecasts it will purchase **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** less and sell **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** less. However, as illustrated by confidential Figure 2 below, the purchases and sales in the April 1 initial filing for the 2021 AUT were **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** respectively, of the final forecasted amounts. This indicates the Company will likely modify its forecasts related to market transactions before its final update in November. Currently, the impact of market transactions is a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** dollar decrease to Net Power Costs.[4] If the 2022 AUT progresses similarly to the 2021 AUT, we can expect a smaller benefit to customers.

FIGURE 2. PURCHASES AND SALES UE 377 TO UE 391

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

[4] Staff/203, PGE's Confidential Response to Staff DR 42, Attachment A (electronic spreadsheet).

Q. Where does PGE primarily trade power?

A. PGE's trading hubs are most frequently **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** Confidential Figure 3 below is an illustration of trading dollars volume in the last few years within those hubs.[5]

FIGURE 3. PGE TRADING HUBS, 2018-2020

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. Does PGE hedge its future energy requirements?

A. Yes, PGE supplements its own generation with power purchased in the wholesale market, utilizing short-[6] and long-term wholesale power purchase contracts.[7] These purchases allow the Company to take positions in power and fuel markets up to five years in advance of physical delivery.[8] PGE also uses

[5] Staff/203, PGE's Confidential Response to Staff DR 89, Attachment A (electronic spreadsheet).
[6] Delivery periods of one month to one year.
[7] Contracts can range from one month to 37 years. PGE's 2018 Annual Report (page 17). https://investors.portlandgeneral.com/static-files/7c433a60-f1ab-48aa-8309-92611cde9600
[8] PGE's 2020 Annual Report, (pages 14 and 15). https://investors.portlandgeneral.com/static-files/1e2f2ecd-9741-496b-b275-31bc2df75174

spot purchases of power in the open market that are made under contracts that range in duration from 15 minutes to one month.[9]

Q. Does PGE transact electricity in the Energy Imbalance Market?

A. Yes. In 2017, PGE joined the western EIM, which allows the Company's generating plants to receive automated dispatch signals from the CAISO for load balancing along with other western EIM participants in five-minute intervals.[10]

Q. Does PGE only make real-time trades in the Energy Imbalance Market?

A. No. When trading power within the EIM, PGE trades in both the prescheduled "day ahead" and the real-time "hour ahead" markets. When examining the weighted average of PGE trades, real time purchases have consistently had **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** than day ahead trades.[11]

[9] PGE's 2020 Annual Report, (page 15). https://investors.portlandgeneral.com/static-files/1e2f2ecd-9741-496b-b275-31bc2df75174
[10] PGE's 2020 Annual Report, (page 16). https://investors.portlandgeneral.com/static-files/1e2f2ecd-9741-496b-b275-31bc2df75174
[11] Staff/203, PGE's Confidential Response to Staff DR 89, Attachment A (electronic spreadsheet).

FIGURE 4. DAY AHEAD AND REAL TIME MARKETS: 2016-2020

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. Does Staff have any adjustments to PGE's forecast?

A. Staff performed its independent review of the data and agrees with the methods used by PGE for analysis and verifies the result. Staff concludes that the forecast is reasonable and has no adjustment.

Q. Has PGE recently updated its risk management policy for wholesale trading?

A. Effective January 1, 2021, PGE updated its risk management protocol to enhance oversight of energy trading. Under the new policy, Power Operations reports to the Vice President of Strategy, Regulation and Energy Supply while the Risk Management group reports through a Risk and Compliance team that reports to the Chief Executive Officer.[12] The revised protocol also prohibits new

[12] Cision PR Newswire "Portland General Electric Announces Conclusion of the Review by the Special Committee of the Board of Directors." December 18, 2020.

transactions that occur at locations for which PGE does not have corresponding transmission rights.[13]

Q. Why did PGE update its risk management policy?

A. In 2020, PGE sustained third quarter trading losses totaling $128 million ("Trading Losses"). According to an independent review, PGE's Trading Losses of $128 million were the result of being caught short in Southwest and California Trading Markets and long in Pacific Northwest markets as wholesale prices spiked and transmission capacity was limited.[14] PGE CEO Maria Pope described the trading event as: "Certain PGE personnel entered into a number of energy trades during 2020 with increasing volume accumulating in the second and into the third quarter resulting in significant exposure."[15] As a result, PGE made several changes to its risk management policies including: having Risk Management report to the CEO and Power Operations report to the Vice President of Strategy, Regulation and Energy Supply; replacing the Power Operations manager; and revising controls on the ability of personnel to enter into wholesale energy transactions to the extent that PGE does not have physical or financial delivery capability.[16] In other words, the new protocol expressly prohibits new transactions that occur in locations for which PGE does not have corresponding transmission rights. The previous Risk

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https://www.prnewswire.com/news-releases/portland-general-electric-announces-conclusion-of-the-review-by-the-special-committee-of-the-board-of-directors-301195896.html

[13] Staff/203, PGE's Confidential Response to Staff DR 89, Attachment A (electronic spreadsheet).

[14] Ernst, Steve, "Report: Short Position in SW, California Led to PGE Trading Losses in Q3," Clearing Up, December 18, 2020. https://www.newsdata.com/clearing_up/clearing_it_up/report-short-position-in-sw-california-led-to-pge-trading-losses-in-q3/article_7a26d9b8-4180-11eb-b04c-f7d8f9875a4b.html

[15] Ibid.

[16] Ibid.

Management policy did not prohibit trades of the volume or location that led to the Trading Losses.[17]

Q. Please describe PGE's updated risk management policy.

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

[17] Staff/202, Cohen/3, PGE's Response to Staff DR 134.
[18] Staff/203, Cohen/10-13, PGE's Confidential Response to Staff DR 61, Attachment B.

[redacted] [END CONFIDENTIAL]

Q. What are some examples of risk limits?

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

Q. What occurs if limits are violated?

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

Q. How does PGE manage market risk exposure?

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[19] Staff/203, Cohen/11, PGE's Confidential Response to Staff DR 61, Attachment B.
[20] Staff/203, Cohen/73-78, PGE's Confidential Response to Staff DR 61, Attachment B.
[21] Staff/203, Cohen/19, 79, PGE's Confidential Response to Staff DR 61, Attachment B.

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

Q. Does PGE seek to include its Trading Losses in its Power Cost Variance Mechanism?

A. No. PGE is not seeking recovery of these costs through the PCVM and has committed that it will not seek recovery of these costs from customers through other rate proceedings.[23]

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[22] Staff/203, Cohen/14-15, PGE's Confidential Response to Staff DR 61, Attachment B.
[23] Staff/204, Cohen/4-5, Media Related to Trading Losses. BofA Global Research. "Portland General Electric Company: Putting Out of a Fire of Their Own: Downgrade to Neutral on Trading Impact," August 25, 2020.

Q. Do you have any recommendations regarding PGE's changes to its Risk Management Policy?

A. No. The prudence of PGE's Risk Management Policy is not at issue in this docket.

ISSUE 2. PGE'S PROPOSED MODEL UPDATE, LYDIA 2.0

Q. How does PGE currently model price shaping within a month?

A. PGE currently utilizes a base model called Lydia 1.0.

Q. Please describe how PGE uses Lydia 1.0.

A. PGE uses Lydia 1.0, for intramonth Mid-C price shaping and wind shaping in order to create hourly price distributions from forward monthly on- and off-peak prices.[24] In the Lydia 1.0 model, Mid-C price shaping and intramonth wind-shaping are performed independently. The hourly prices follow a set of normalized price distributions (also known as "scalars") for each week sub-period (weekdays, Saturday and Sunday). All the weekdays, Saturdays and Sundays within the month have the same respective shape, resulting in hourly energy curves representing an average week for each given month. For wind shaping, a five-year moving average methodology is used, meaning 2022 is based on the previous five years of historical wind generation data. PGE uses an annual capacity factor to represent the average wind generation over the last five years, a monthly shape factor that reflects the monthly average generation over the last five years and an hourly shape factor that represents the average generation by hour-month in the last five years. This results in an output where all days within the given month have the same 24-hour shape profile and no intramonth variability.[25]

Q. Why is PGE proposing an updated model, Lydia 2.0?

[24] PGE/100, Vhora-Outama-Batzler/20.
[25] PGE/100, Vhora-Outama-Batzler/22.

A. PGE claims the current model fails to capture the price volatility in the day-ahead market due to wind generation. Accordingly, wind exhibits a negative correlation to Mid-C energy prices in that high wind days result in lower Mid-C prices while low wind days result in higher Mid-C prices.[26] Because wind generation impacts energy prices in the day-ahead market and there are no available generation signals on the term forward basis, the market exposure to wind forecasting is considerable.[27] Day ahead, Hour ahead and intrahour Mid-C prices are driven by wind in the region.[28] Lydia 2.0 is an attempt to gauge Mid-C prices and improve the model's Mid-C price shaping using more nuanced information on wind generation.

Q. What impact does the Lydia 2.0 enhancement have on net power costs?

A. Lydia 2.0 results in a 2022 NVPC forecast increase of approximately $5.6 million.

Q. What does Lydia 2.0 change in PGE's modeling?

A. The Lydia 2.0 enhancement produces intramonth redistribution of wind generation and Mid-C prices by adding four wind generation profiles: High, High-Medium, Low-Medium and Low or "Wind Quartiles".[29] **[BEGIN CONFIDENTIAL]** [redacted]

[26] PGE/100, Vhora-Outama-Batzler/21.
[27] Ibid.
[28] UE 391 – Confidential Workpaper Monet Updates MFR 04-06-2021 Vol 9 – Enhancements and New Items – Step 00B Lydia 2.0 - #11PGE_NVPC Forecast_2022
[29] PGE/100, Vhora-Outama-Batzler/23.

[redacted]

[END CONFIDENTIAL]

Q. Please explain how the normalized factor is derived and provide an example.

[**BEGIN CONFIDENTIAL]**

[redacted]

[30] UE 391 – Confidential Workpaper Monet Updates MFR 04-06-2021 Vol 9 – Enhancements and New Items – Step 00B Lydia 2.0 - #04NVPC methodology update_AUT 2022_Lydia 2.0
[31] Ibid.

[redacted]

FIGURE 5. LYDIA 2.0 NORMALIZING FACTOR

[redacted]

FIGURE 6. NORMALIZING CALCULATION EXAMPLE

[redacted]

[32] UE 391 – Confidential Workpaper Monet Updates MFR 04-06-2021 Vol 9 – Enhancements and New Items – Step 00B Lydia 2.0 - #04NVPC methodology update_AUT 2022_Lydia 2.0
[33] Ibid.

[redacted]

FIGURE 7. AVERAGE WIND SHAPE FACTORS

[redacted]

[END CONFIDENTIAL]

Q. How is the Average Price Shape for Mid-C derived?

[BEGIN CONFIDENTIAL]

[redacted]

[34] UE 391 – Confidential Workpaper Monet Updates MFR 04-06-2021 Vol 9 – Enhancements and New Items – Step 00B Lydia 2.0 - #04NVPC methodology update_AUT 2022_Lydia 2.0
[35] Ibid.

FIGURE 8. PRICE SHAPE CALCULATION

[redacted]

FIGURE 9. WIND PRICE SHAPE CALCULATION

[redacted]

[36] Ibid.
[37] Ibid.

[redacted]

FIGURE 10. AVERAGE PRICE SHAPE CALCULATION

[redacted]

[END CONFIDENTIAL]

Q. How do the results from Lydia 2.0 compare to Lydia 1.0?

A. The four wind profiles average back to the base case Lydia 1.0 methodology. That is, in each month the four wind generation profiles average back to the one wind generation profile. Moreover, the average of the on-peak and off-peak hourly prices for the four profiles is equal to the forward Mid-C on-peak and off-peak monthly price curve.[39] **[BEGIN CONFIDENTIAL]** [redacted]

[38] UE 391 – Confidential Workpaper Monet Updates MFR 04-06-2021 Vol 9 – Enhancements and New Items – Step 00B Lydia 2.0 - #04NVPC methodology update_AUT 2022_Lydia 2.0
[39] PGE/100, Vhora-Outama-Batzler/23.
[40] UE 391 – Confidential Workpaper Monet Updates MFR 04-06-2021 Vol 9 – Enhancements and New Items – Step 00B Lydia 2.0 - #04NVPC methodology update_AUT 2022_Lydia 2.0

FIGURE 11. FOUR WIND PROFILES AVERAGE TO LYDIA 1.0

[redacted]

[END CONFIDENTIAL]

Q. Does Staff have an adjustment to Lydia 2.0?

A. No, Staff supports this change as Lydia 2.0 captures the price volatility related to wind generation in the day-ahead market and will improve the Company's Mid-C price shaping.

ISSUE 3. PELTON ROUND BUTTE (PRB) TRIBAL OWNERSHIP CHANGE

Q. What is PGE's current ownership of PRB and how is that purported to change?

A. PGE owns 66.7 percent of PRB with the remaining 33.3 percent owned by the Confederated Tribes of the Warm Springs Reservation of Oregon (Tribes). The Tribes have elected to increase their ownership share to 49.99 percent on January 1, 2022.[41] The impact of this change will be an increase to power costs of $8.8 million.[42]

Q. What is the history of the Pelton Round Butte ownership?

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

[41] PGE/100, Vhora-Outama-Batzler/45.
[42] Staff/202, Cohen/1-2, PGE's Response to Staff DR 60.
[43] UE 391 – Workpapers – Confidential – Attachment 1_Confidential MFRs – Vol 5 – Contracts PGE's April 15 MFR, Vol 5- Contracts\Tribes Allocation Agreement - #_2022AUTTribesAllocationAgreement

[redacted] **[END CONFIDENTIAL]**

Q. What is the cost of the Tribes' increase in ownership?

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

[END CONFIDENTIAL]

Q. Does Staff have an adjustment?

A. No, but Staff notes that PGE erroneously equated the impact of the ownership change to be $9.3 million in its testimony but not in the actual NVPC forecast.[47]

[44] UE 391 – Workpapers – Confidential – Attachment 1_Confidential MFRs – Vol 5 – Contracts PGE's April 15 MFR, Vol 5- Contracts\Tribes Allocation Agreement -#_UE 283/PGE/1500, Pope-Tooman
[45] UE 391 – Confidential Workpaper MFR 04-06-2021 #2022 AUT-001
[46] Staff calculates this amount as $8,819,767 based on the instructions provided in PGE's Response to Staff DR 60.
[47] Staff/202, Cohen/1-2, PGE's Response to Staff DR 60.

The Company has agreed to file the correct number in an upcoming errata filing.

Q. Is this amount likely to change?

A. Because the impact of ownership share payments is dependent on forward market prices, these amounts can and will change with every subsequent MONET forward price curve update. The filing amount is based on contracts and forward market price curves as of February, 2021.[48]

Q. Does this conclude your testimony?

A. Yes.

[48] Staff/202, Cohen/1, PGE's Response to Staff DR 60.

CASE: UE 391
WITNESS: HEATHER COHEN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 201

Witness Qualifications Statement

June 30, 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 391
WITNESS: HEATHER COHEN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 202

Exhibits in Support
Of Opening Testimony

June 30, 2021

May 19, 2021

TO: Heather Cohen
Public Utility Commission of Oregon

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC COMPANY
UE 391
PGE Response to OPUC Data Request No. 060
Dated May 5, 2021

Request:

In PGE/100, Vhora – Outama – Baltzer/45 PGE states that the increase of the Confederated Tribes' ownership of the Pelton-Round Butte will increase the 2022 NVPC forecast by $9.3 million.

a. Please provide PGE's calculation of this value in electronic workbook format with all cells and formulas intact. Ensure that all input data is included.
b. Please include a step-by-step narrative of how PGE performed the calculation provided in section a above, including the dollar amounts per step (i.e dollar amount cost for full share, dollar amount value of the energy provided for the Cove Obligations, etc).
c. Please reference all PGE work papers with these steps.

Response:

a. In PGE Exhibit 100, PGE inadvertently misstated the net variable power cost impact associated with the increase in the Confederated Tribes' ownership share from 33.3% to 49.9% at Pelton-Round Butte as $9.3 million. The $9.3 million referenced was based on contracts and forward market price curves as of December 30, 2020, rather than the curve snapshot PGE used when filing its initial 2022 AUT forecast. The actual power cost impact reflected in PGE's initial 2022 NVPC forecast submitted on April 1, 2021 is an increase of $8.9 million, which is based on contracts and forward market price curves as of February 26, 2021.

   Attachment 060-A provides a workpaper reflecting the power cost impact associated with the increase in the Confederated Tribes' ownership of the Pelton-Round Butte hydro facility.

   It is also important to note that the net variable power cost impact associated with the expected change in ownership share is dependent on forward market prices and thus will change with each subsequent MONET forward price curve update.

b. To reflect the NVPC impact associated with the increase in the Confederated Tribes' ownership share, PGE reversed the following inputs in the initial 2022 NVPC forecast, as provided in Attachment 060-A:
   - PGE changed PGE's share from 50.01% in the April 1, 2021 MONET Output to 66.67%, as reflected in PGE's final 2021 NVPC forecast: See worksheet "PC Input", Cell F353. The change in PGE's share impacts the following:
     - Cove Replacement to PPL: see worksheet "PC Input", rows 352-354.
     - Tribes Allocation Agreement costs: see worksheet "PC Input", rows 386-400.
   - PGE reversed the fixed payments amounts reflected in the worksheet "PC Input", Cell H398, to the value modeled in PGE's final 2021 NVPC forecast. For more details regarding variable and fixed costs associated with the Tribes Allocation Agreement, please see April 15 MFRs, Vol 5 - Contracts\Tribes Allocation Agreement.
   - These changes result in a decrease to PGE's initial 2022 initial NVPC forecast as filed on April 1, 2021, of approximately $8.9 million reflected in worksheet "Step Log", cell R6, which essentially reflects the power cost impact from updating PGE's ownership share at Pelton-Round Butte since the model step is increasing PGE's share back to 66.67%, as modeled in PGE's 2021 final NVPC forecast.

c. Please see PGE's April 15 MFRs, Vol 5 - Contracts\Tribes Allocation Agreement. Document "#_2022AUTTribesAllocationAgreement" provides a narrative description of the modeling associated with the Tribes Allocation Agreement, including all the work papers used in support of this modeling, which are provided within the referenced MFR.[1]

Attachment 060-A is protected information subject to Protective Order No. 21-099.

[1] Please note that in the MONET model, costs associated with Tribes Allocation Agreement are modeled separately from the energy modeling for the Pelton-Round Butte facility. The energy generation modeling for the Pelton-Round Butte facility is based on the Northwest Power Pool's PNCA Headwater Benefits Study (HWBS) as provided in the April 15 MFRs, Vol 4 - Hydro\Energy.

June 24, 2021

TO: Heather Cohen
Public Utility Commission of Oregon

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC COMPANY
UE 391
PGE Response to OPUC Confidential Data Request No. 134
Dated June 10, 2021

Request:

In regards to PGE's 2020 third quarter losses, the Company declared these losses to be "outside the Company's acceptable risk tolerance."[1]

a. Please explain how these transactions were allowed to occur under the Company's previous Risk Management Policy.

b. Please elaborate on the "revised policies designed to prevent positions of the type that led to the losses."[2] What controls are placed on personnel to prevent these trading losses and how does this differ from the previous risk management policy?

Response:

a. PGE objects to this request on the basis that it is vague. "Allowed to occur" lends itself to many interpretations. For purposes of responding to this request, PGE interprets this request as asking whether the previous Risk Management Policy prohibited these transactions. With that interpretation, and without waiving and notwithstanding this objection, PGE responds as follows: The previous Risk Management Policy did not expressly prohibit trades of the volume or location that led to the announced trading losses.

b. The revised Risk Management Policy expressly prohibits new transactions that occur at locations for which PGE does not have corresponding transmission rights. Additionally, the Company has significantly strengthened the limit structure in regard to locations and volumes and has strengthened the oversight of power operations strategies.

[1] PGE 10-K 2020 (page 32). https://investors.portlandgeneral.com/static-files/f4715cf8-2b04-4c0f-a70a-f33d7b32449d
[2] PGE 10-K 2020 (page 33). https://investors.portlandgeneral.com/static-files/f4715cf8-2b04-4c0f-a70a-f33d7b32449d

CASE: UE 391
WITNESS: HEATHER COHEN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 203

Exhibits in Support
Of Opening Testimony

CONFIDENTIAL
June 30, 2021

STAFF EXHIBIT 203

IS CONFIDENTIAL AND SUBJECT TO

PROTECTIVE ORDER NO. 21-099

CASE: UE 391
WITNESS: HEATHER COHEN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 204

Exhibits in Support
Of Opening Testimony

June 30, 2021

Docket No: UE 391

BofA SECURITIES

BofA GLOBAL RESEARCH

Portland General Electric Company

Putting out a Fire of Their Own: Downgrade to Neutral on Trading Impact

25 August 2020 | Equity | United States | Electric Utilities

POR US

Rating Change	Price	Price Objective	Upside	Market Cap	Average Daily Value	2020E EPS	2021E EPS	2022E E
NEUTRAL ▼	41.96	41.00 ▼	-2.3%	3,751	24.51	1.46 ▼	2.47 ▼	2.65
from BUY	USD	from 45.00 USD		USD(mn)	USD(mn)	from 2.36 USD	from 2.50 USD	from 2.`

all data as of 25 August 2020

Key takeaways

- Trading losses incurred from CA vol push us to downgrade to Neutral. expect sharp cautious reaction given legacy context
- Relative paucity of details around EPS & baseline adds to confusion; mgmt keen to minimize impact beyond 1x increase in debt
- We now see potential OR PUC involvement as key overhang: reduce PO to $41/sh pending clarity on regulatory involvement.

Trading losses disclosed from Western power volatility

Portland General Electric Company (POR) mgmt. disclosed post close it had suffered an "illconceived" power trade in California resulting in $155 Mn losses (largely realized) through 3Q, resulting principally from latest power volatility in California. While demand/weather have been extreme, the substantial exposure to a fully regulated utility is highly unusual - and several personnel have been put on leave. We note functions involving risk have been reassigned to direct oversight by CEO, Maria Pope and Power Supply over to CFO Lobdell. We see the development as concerning over risk controls employed at the company, particularly glaring given the company's involvement in the last energy crisis in CA dating back 2000-01, when it was owned under Enron (the latest is unrelated, but nonetheless may ward off utility investors for some time given the substantial volatility introduced into EPS). We anticipate a sharp negative reaction; we downgrade to Neutral seeing risk of a yet wider discount vs utility peers (we assume -2x discount) depending on Oregon Public Utilities Commission (OR PUC) response (and associated impacts of any investigation/revision to policies/ focus on authorized capital structure).

PO to $41, Downgrade to Neutral; where else to look?

We downgrade shares of POR to Neutral from Buy following the disclosed trading losses that could reach $155 Mn. While not having a material impact on our '22 estimates, we adjust our valuation to reflect a -2.0x discount to the peer group (from -1.0x discount) to reflect what we expect could be a protracted period of uncertainty hanging over shares given recent capex revisions and newfound concerns over internal controls and risk management. We would not doubt volatility/pressure on other regional peers pending their own affirmations of their own trading positions given recent substantial volatility in California/Western power markets between extreme heat and unexpected rolling blackouts alongside outages driven by fires. Peer companies likely to see 'mild' read-through include Pinnacle West (PNW), Idacorp (IDA), Northwestern Corp (NWE), Black Hills (BKH), and Avista Corp (AVA). We perceive limited risks but several have some modest degree of off-system sales (in these cases, could very well prove to be a tailwind to 3Q results).

BofA SECURITIES

BofA GLOBAL RESEARCH

Estimates & Valuation

Estimates (Dec)

(US$)	2018A	2019A	2020E	2021E	2022E
EPS	2.37	2.39	1.46	2.47	2.65
GAAP EPS	2.37	2.39	1.46	2.47	2.65
EPS Change (YoY)	3.5%	0.8%	-38.9%	69.2%	7.3%
Consensus EPS (Bloomberg)			2.40	2.58	2.72
DPS	1.43	1.54	1.61	1.70	1.81

Valuation (Dec)

	2018A	2019A	2020E	2021E	2022E
P/E	17.7x	17.6x	28.7x	17.0x	15.8x
GAAP P/E	17.7x	17.6x	28.7x	17.0x	15.8x
Dividend Yield	3.4%	3.7%	3.8%	4.1%	4.3%
EV / EBITDA*	12.3x	11.8x	12.6x	10.2x	9.8x
Free Cash Flow Yield*	0.9%	-1.6%	-5.0%	1.5%	4.6%

* Click for full definitions of *iQmethod*SM measures.

Quarterly Estimates

Quarterly Earnings Estimates

	2019	2020
Q1	0.82A	0.91A
Q2	0.28A	0.43A
Q3	0.61A	0.17E
Q4	0.68A	-0.05E

Key Changes

(US$)	Previous	Current

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Inv. Opinion	B-1-7	B-2-7
Inv. Rating	BUY	NEUTRAL
Price Obj.	45.00	41.00
2020E Rev (m)	2,143.4	2,192.7
2021E Rev (m)	2,238.5	2,235.9
2022E Rev (m)	2,313.1	2,311.3
2020E EPS	2.36	1.46
2021E EPS	2.50	2.47
2022E EPS	2.70	2.65

Stock Data

Price	41.96 USD
Price Objective	41.00 USD
Date Established	25-Aug-2020
Investment Opinion	B-2-7
52-Week Range	37.83 USD - 63.08 USD
Mrkt Val (mn) / Shares Out (mn)	3,751 USD / 89.4
Average Daily Value (mn)	24.51 USD
BofA Ticker / Exchange	POR / NYS
Bloomberg / Reuters	POR US / POR.N
ROE (2020E)	5.1%
Net Dbt to Eqty (Dec-2019A)	100.1%

Average Daily Volume	579,233

Implications of Energy Trading loss

POR reported that its Q3 and full-year 2020 results will include an impact from losses on wholesale energy trading estimated at $155 Mn - note the final amount of the losses is as yet unknown as $104m are realized with remaining positions still left to be unwound. In response to the loss which mgmt. attributes to a failure of internal controls and procedures within its energy trading arm, the company is reducing its 2020 outlook while maintaining its 4-6% long-term growth target.

- **2020 guidance cut to $1.30-1.60.** Mgmt. reduced its EPS target for 2020 by 90 cents at the midpoint from $2.20-2.50 previously following the disclosure of the unauthorized trading loss. While specific trading positions that led to the loss were not disclosed, the company's release cited extreme weather conditions in the California Independent System Operator (CAISO) service territory as driving volatility in wholesale power prices in the month of August. We note that an open question remains the timing of the disclosure happening so soon after the company reported its Q2 results, with the press release seeming to

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suggest that the position was known at the end of June. We note that the total cash impact of $155 Mn in impact does *not* necessarily reconcile with the earnings impact implied about $100 Mn pre-tax. We look for clarity on earnings recognition as positioned are closed out (presumably the bulk of hedge positions appear to be recognized in the current year).

- **Mgmt. sees long-term intact; *not* 'rebasing' 4-6%.** POR mgmt. stressed that the trading loss is expected to be a one-time isolated event and that it will not impact the long-term trajectory of the company. The 4-6% EPS target growth rate is not being rebased from the lower 2020 midpoint as the company stated that it does not expect longer-term impacts to persist beyond the current year. *Given the lack of clarity on long-term EPS guidance to begin with - we see the lack of clarity on just what 'reaffirming' its 4-6% EPS means could compound concerns around shares.* While we do not want to overstate the largely one-time nature of the impact, we see clear negative revisions to below Street consensus on a go forward basis from ongoing financing impacts at a minimum.

- **Not seeking recovery through PCAM.** Note that POR will *not* be submitting the increase in net variable power cost through its Power Cost Adjustment Mechanism (PCAM) for recovery from customers through rates - the company cited failures in internal controls (i.e. costs not prudently incurred) and has convened a board committee to review the specific failures that led to the loss. POR expects the PCAM mechanism to continue operating as it had before and not to be impacted by the 2020 trading loss.

We could also see POR pursue substantially lower risk efforts on hedging -while not clear how this would manifest itself could result in ongoing PCAM exposure (which admittedly is largely an over *or* under-earning mechanism). While clear that management would *not* seek to recover these costs under its fuel clause; we would not doubt an investigation at the OR PUC into just what former losses absorbed by customers have been.

- **Regulatory response remains uncertain.** We expect the OR commission to open its own review of the trading losses reported, with a focus on how POR's internal controls failed to detect and prevent the loss from growing to such an extent. While it is early to say what steps the commission will take in response, we could see changes to the construct of the fuel recovery mechanism. Key questions we expect a focus on will be whether the current regulatory construct encourages or otherwise incentivizes the kind of risk taking that resulted in POR's loss. While the silver lining could result in less fuel risk, we anticipate a structurally higher degree of rigor to be taken in analyzing efforts undertaken by the company. *Bottom line, this is the 'next' risky point in shares and could limit an immediate 'buy the dip' reaction.*

- **Another disappointing data point presents challenge to mgmt. Board process is now venue to provide any 'official' update.** With the announcement of an ongoing board review of the failures that led to the large trading loss representing the latest in a series of challenging revisions in 2020 already. We look for changes among ranks in coming months as a potential outcome, particularly following earlier challenges in the year. *We look for clear affirmation of team and policies upon conclusion of board review.*

- **No additional equity *(for now)* but focus on regulated cap structure.** After capex downward revisions earlier in the year led some investors to focus on the health of POR's balance sheet, we note that mgmt. has indicated that it does not plan to have to issue additional equity in order to fund any shortfalls from the latest incident- and does not expect to modify its capex plan further as a result of the trading loss. We note that following the latest disclosure, we see consolidated FFO/debt falling to about 16% in 2020 before rebounding to an 18-19% range in future years. Mgmt. has indicated that it intends to absorb the impact of the loss for now with incremental leverage given the latitude in its credit metrics. However, there remains the ongoing question of the target capital structure given that POR's regulated equity layer *is* driven by the company (there is no bifurcation between holding company and opco). As such, this remains the other parallel concern on the margin into any future case.

Table 1: POR consolidated debt metrics

CFO / Pre-W/C Debt	2017A	2018A	2019A	2020E	2021E	2022E	2023E	2024E	2024E
Cash Flow From Operations	597	630	546	552	621	671	687	714	735
- Changes in Working Capital	26	30	112	-16	35	-27	-27	-27	-27
- Changes in Short Term Op. Assets & Liabs.									
Adjustments	-4	-4	-4	-4	-4	-4	-4	-4	-4
Short-term debt	0	0	0	18	19	19	19	18	18
+ Long-term Debt - Gross	2,426	2,478	2,613	2,924	3,020	3,010	2,994	2,962	2,920
Adjustments	349	349	349	349	349	349	349	349	349
FFO/Debt	**22.29%**	**23.19%**	**22.07%**	**16.15%**	**19.26%**	**18.95%**	**19.49%**	**20.49%**	**21.39%**

Source: BofA Global Research estimates

Bottom line: the disclosed trading loss is no doubt a cautious data point, and we will watch for additional communication from company mgmt. on the outcome of its internal review. Looking ahead, we expect that shares of POR will trade at a discount to the peer group following a series of disappointing reports and revisions in 2020 until the cloud of uncertainty stemming from the disclosed losses begins to lift - we see potential for re-rating of shares as likely pushed out following the news of the trading loss.

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Estimates

We adjust our estimates, principally reducing the 2020 number to near the midpoint of mgmt.'s updated 2020 guidance range of $1.30-1.60 (previously $2.20-2.50). Our new '20 estimate is above Street consensus though we expect numbers to be revised meaningfully downward following the latest company update. We reduce '21-23 estimates incrementally having already been below Street consensus as the company reflects confidence in being able to limit the impact from the trading loss to 2020 and maintain its long-term 4-6% EPS guidance range (note mgmt. did not rebase its long-term guidance to the lower '20 estimate).

Table 2: POR updated estimates

POR Dashboard	2019A	2020E	2021E	2022E	2023E
EPS Estimates	**$2.39**	**$1.46**	**$2.47**	**$2.65**	**$2.74**
Prior BofA estimates	$2.39	$2.36	$2.50	$2.70	$2.77
Street Consensus EPS	**$2.39**	**$2.40**	**$2.58**	**$2.72**	**$2.86**
Mgmt Guidance - EPS	**$2.35 - $2.50**	**1.30-1.60**			
EPS Guidance: LT Growth 4-6% over Time	*$2.49*	*$2.51*	*$1.53*	*$2.59*	*$2.78*
4% Growth y/y	*$2.46*	*$2.49*	*$1.52*	*$2.56*	*$2.76*
6% Growth y/y	*$2.51*	*$2.53*	*$1.55*	*$2.61*	*$2.81*
DPS	**$1.54**	**$1.61**	**$1.70**	**$1.81**	**$1.91**
Dividend Payout Ratio (BofA)	64.45%	110.16%	69.10%	68.13%	69.82%
DPS Growth	7.88%	4.35%	6.00%	6.00%	6.00%
GAAP ROE	8.40%	5.07%	8.51%	8.92%	8.98%
Ratebase ROE	8.69%	5.04%	8.18%	8.65%	8.87%
FFO/Debt	22.07%	16.15%	19.26%	18.95%	19.49%

Source: BofA Global Research, Bloomberg

Valuation: PO to $41, downgrade to Neutral

We adjust our valuation of POR to reflect what we perceive will be a discount story going forward. We now apply a -2.0x valuation discount to our electric peer group multiple, updated from a -1.0x discount previously, and mark to market the latest electric peer multiple of 16.8x from 17.0x previously. We expect a structurally higher discount rate looking ahead, given the legacy of the company tied back to its prior ownership under Enron and associated uncertainties tied to Western power trading. We anticipate investors will take a uniquely cautious view of recent actions given this backdrop and think shares could trade in the near-term to among the widest discounts in the utility sector. Given the (historic) lack of disclosure from management (largely due its perceived conservative culture), *uncertainty* around its earnings outlook (admittedly not all smid-cap shares offer long-term EPS CAGRS to being with - explaining their discount to large-cap peers), and finally uncertainty on ramifications.

Our updated PO is $41, reflecting a modest positive return when factoring in the stock's dividend yield, and accordingly downgrade our rating from Buy to Neutral. We stress dividend should remain intact *despite* the trading impact.

We could see shares trade down to -3x discount depending on regulatory response adopted in our view among other scenarios.

Table 3: POR updated valuation

			Low Case		Base Case				High Case	
Business Segment	**Valuation Metric**	**2022 EPS**	**Valuation Multiple**	**($/sh) Value**	**Base Valuation Multiple**			**($/sh) Value**	**Valuation Multiple**	**($/sh) Value**
					Peer Multiple	Prem/Disc to Peer	Base Multiple			
Group Peer Multiple - Electric					**16.8x**					
Group EPS '18-'22 CAGR - Electric					**5.00%**					
Portland General Electric Company	P/E	**$2.65**	14.6x	$39.00	**17.6x**	**-2.0x**	15.6x	$41.45	16.6x	$44.00
Shares Outstanding		90								
Total Return Analysis										
Price Objective				**$39.00**				**$41.00**		**$44.00**
Upside/Downside Potential								-2.29%		
NTM Dividend Yield								3.83%		
Total Return Potential								**1.54%**		

Source: BofA Global Research estimates, Bloomberg

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Click for important disclosures. Analyst Certification. Price Objective Basis & Risk.

*iQprofile*SM Portland General Electric Company

Company Description

Portland General Electric Company is a vertically integrated electric utility based in Portland, Oregon. POR serves approximately 818,000 residential, commercial, and industrial customers. Approximately 30% of the purchased power and generation consists of hydro and wind.

Investment Rationale

We rate shares Neutral following the latest disclosure of a substantial energy trading loss incurred in Q2-Q3 2020 which we expect will overshadow utility growth fundamentals in the near term. We see the company as well positioned in '20 to deploy $140Mn in latest incremental capex with potential for yet additional capex as they roll forward another year. 2020 should see the greatest uptick to LT capex from its latest IRP, with clarity by year-end.

*iQ*method SM - Bus Performance*

(US$ Millions)	2018A	2019A	2020E	2021E	2022E
Return on Capital Employed	4.1%	4.0%	2.8%	4.1%	4.4%
Return on Equity	8.6%	8.4%	5.1%	8.5%	8.9%
Operating Margin	17.4%	16.6%	13.6%	19.9%	20.7%
Free Cash Flow	35	(60)	(188)	56	171

*iQ*method SM - Quality of Earnings*

(US$ Millions)	2018A	2019A	2020E	2021E	2022E
Cash Realization Ratio	3.0x	2.6x	4.2x	2.8x	2.8x
Asset Replacement Ratio	1.6x	1.5x	1.8x	1.3x	1.1x
Tax Rate	7.4%	11.2%	23.5%	23.5%	23.5%
Net Debt-to-Equity Ratio	94.1%	100.1%	114.1%	114.2%	110.6%
Interest Cover	2.8x	2.8x	2.3x	3.0x	3.0x

Income Statement Data (Dec)

(US$ Millions)	2018A	2019A	2020E	2021E	2022E
Sales	1,991	2,123	2,193	2,236	2,311
% Change	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

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% Change	-0.9%	6.6%	3.3%	2.0%	3.4%
Gross Profit	NA	NA	NA	NA	NA
% Change	NA	NA	NA	NA	NA
EBITDA	728	762	714	879	920
% Change	1.0%	4.7%	-6.3%	23.1%	4.7%
Net Interest & Other Income	(124)	(128)	(132)	(147)	(158)
Net Income (Adjusted)	**212**	**214**	**131**	**221**	**238**
% Change	**3.9%**	**0.9%**	**-39.0%**	**69.4%**	**7.7%**

Free Cash Flow Data (Dec)

(US$ Millions)	2018A	2019A	2020E	2021E	2022E
Net Income from Cont Operations (GAAP)	212	214	131	221	238
Depreciation & Amortization	382	409	415	434	442
Change in Working Capital	(30)	(112)	16	(35)	(9)
Deferred Taxation Charge	(17)	6	3	2	1
Other Adjustments, Net	83	29	(13)	0	0
Capital Expenditure	(595)	(606)	(740)	(565)	(500)
Free Cash Flow	**35**	**-60**	**-188**	**56**	**171**
% Change	**-57.8%**	**NM**	**-213.1%**	**NM**	**204.0%**

Balance Sheet Data (Dec)

(US$ Millions)	2018A	2019A	2020E	2021E	2022E
Cash & Equivalents	119	30	30	31	32
Trade Receivables	193	167	159	180	187
Other Current Assets	331	303	306	311	317
Property, Plant & Equipment	6,887	7,161	7,484	7,613	7,669
Other Non-Current Assets	580	733	733	733	733
Total Assets	**8,110**	**8,394**	**8,712**	**8,868**	**8,938**
Short-Term Debt	300	16	18	19	19
Other Current Liabilities	491	503	515	505	509
Long-Term Debt	2,178	2,597	2,924	3,020	3,010
Other Non-Current Liabilities	2,635	2,687	2,690	2,692	2,692
Total Liabilities	**5,604**	**5,803**	**6,147**	**6,235**	**6,229**
Total Equity	**2,506**	**2,581**	**2,552**	**2,633**	**2,709**
Total Equity & Liabilities	**8,110**	**8,384**	**8,699**	**8,868**	**8,938**

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* Click for full definitions of *iQmethod*SM measures.

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Price Objective Basis & Risk

Portland General Electric Company (POR)

Our $41 price objective is based on our 2022E EPS estimate. We value shares based on a 2022E P/E methodology applying a 2.0x discount multiple to the 2022 regulated utility PE multiple of 16.8x. Electric peer P/E multiple is grossed up for a year to 2020 by 5% to reflect capital appreciation across the sector. Our 2.0x discount multiple is based off the near time uncertainty and lack of clarity on trajectory and negative sentiment following the Aug 2020 reported energy trading loss estimated at $155m. While our PO is a 12-month forward projection, we use a 2022 multiple, which is reflective of a discount back to 2020.

Downside risks are 1) the ability to secure commission approval for future wind builds, 2) power market risk due to the Power Cost Adjustment Mechanism (PCAM). Upside risks are 1) continuation of small/midcap regulated rally, 2) better than expected weather adjusted load growth, 3) further strengthening of company balance sheet, 4) power market risk due to the PCAM.

Coverage Cluster

North American Utilities, Alternative Energy & LNG Coverage Cluster

Investment rating	Company	BofA Ticker	Bloomberg symbol	Analyst
BUY				
	AES	AES	AES US	Julien Dumoulin-Smith
	Alliant Energy Corporation	LNT	LNT US	Julien Dumoulin-Smith
	AltaGas	YALA	ALA CN	Julien Dumoulin-Smith
	Atlantica Yield	AY	AY US	Julien Dumoulin-Smith
	Atmos Energy Corporation	ATO	ATO US	Richard Ciciarelli, CFA
	Avista	AVA	AVA US	Richard Ciciarelli, CFA
	Clearway Energy	CWENA	CWEN/A US	Julien Dumoulin-Smith
	Clearway Energy	CWEN	CWEN US	Julien Dumoulin-Smith
	CMS Energy	CMS	CMS US	Julien Dumoulin-Smith
	Consolidated Edison	ED	ED US	Julien Dumoulin-Smith
	DTE Energy	DTE	DTE US	Julien Dumoulin-Smith
	Edison International	EIX	EIX US	Julien Dumoulin-Smith
	Emera Inc	YEMA	EMA CN	Julien Dumoulin-Smith
	Entergy	ETR	ETR US	Julien Dumoulin-Smith
	Essential Utilities	WTRG	WTRG US	Julien Dumoulin-Smith
	Evergy, Inc	EVRG	EVRG US	Julien Dumoulin-Smith

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First Solar, Inc.	FSLR	FSLR US	Julien Dumoulin-Smith
FirstEnergy	FE	FE US	Julien Dumoulin-Smith
Idacorp	IDA	IDA US	Julien Dumoulin-Smith
NextEra Energy	NEE	NEE US	Julien Dumoulin-Smith
NRG Energy	NRG	NRG US	Julien Dumoulin-Smith
OGE Energy Corp	OGE	OGE US	Julien Dumoulin-Smith
PG&E Corporation	PCG	PCG US	Julien Dumoulin-Smith
PNM Resources Inc.	PNM	PNM US	Julien Dumoulin-Smith
PPL Corporation	PPL	PPL US	Julien Dumoulin-Smith
Sempra Energy	SRE	SRE US	Julien Dumoulin-Smith
Spire	SR	SR US	Richard Ciciarelli, CFA
Sunnova Energy	NOVA	NOVA US	Julien Dumoulin-Smith
SunRun	RUN	RUN US	Julien Dumoulin-Smith
Vistra Energy	VST	VST US	Julien Dumoulin-Smith

NEUTRAL

Ameren Corporation	AEE	AEE US	Julien Dumoulin-Smith
American Electric Power	AEP	AEP US	Julien Dumoulin-Smith
Avangrid	AGR	AGR US	Julien Dumoulin-Smith
Black Hills Corporation	BKH	BKH US	Julien Dumoulin-Smith
CenterPoint Energy	CNP	CNP US	Julien Dumoulin-Smith
Cheniere Energy Inc	LNG	LNG US	Julien Dumoulin-Smith
Dominion Energy	D	D US	Julien Dumoulin-Smith
Duke Energy	DUK	DUK US	Julien Dumoulin-Smith
Hannon Armstrong	HASI	HASI US	Julien Dumoulin-Smith
Hydro One	YH	H CN	Julien Dumoulin-Smith
NextDecade	NEXT	NEXT US	Julien Dumoulin-Smith
NextEra Energy Partners	NEP	NEP US	Julien Dumoulin-Smith
NiSource Inc	NI	NI US	Julien Dumoulin-Smith
ONE Gas, Inc.	OGS	OGS US	Richard Ciciarelli, CFA
Pinnacle West	PNW	PNW US	Julien Dumoulin-Smith
Portland General Electric Company	POR	POR US	Julien Dumoulin-Smith
Public Service	PEG	PEG US	Julien Dumoulin-Smith

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	Enterprise Group			
	Southern Company	SO	SO US	Julien Dumoulin-Smith
	Tellurian Inc	TELL	TELL US	Julien Dumoulin-Smith
	Xcel Energy Inc	XEL	XEL US	Julien Dumoulin-Smith
UNDERPERFORM				
	Algonquin Power & Utilities Corp	AQN	AQN US	Julien Dumoulin-Smith
	Algonquin Power & Utilities Corp	YAQN	AQN CN	Julien Dumoulin-Smith
	American Water Works	AWK	AWK US	Julien Dumoulin-Smith
	Bloom Energy	BE	BE US	Julien Dumoulin-Smith
	Eversource Energy	ES	ES US	Julien Dumoulin-Smith
	Exelon	EXC	EXC US	Julien Dumoulin-Smith
	Fortis	YFTS	FTS CN	Julien Dumoulin-Smith
	Fortis Inc	FTS	FTS US	Julien Dumoulin-Smith
	Hawaiian Electric Industries	HE	HE US	Julien Dumoulin-Smith
	MGE Energy	MGEE	MGEE US	Julien Dumoulin-Smith
	New Jersey Resources Corp	NJR	NJR US	Richard Ciciarelli, CFA
	Northwest Natural Holdings	NWN	NWN US	Richard Ciciarelli, CFA
	NorthWestern Corporation	NWE	NWE US	Julien Dumoulin-Smith
	South Jersey Industries	SJI	SJI US	Richard Ciciarelli, CFA
	SunPower Corp.	SPWR	SPWR US	Julien Dumoulin-Smith
	Unitil Corporation	UTL	UTL US	Julien Dumoulin-Smith
	WEC Energy Group Inc	WEC	WEC US	Julien Dumoulin-Smith
RSTR				
	Vivint Solar	VSLR	VSLR US	Julien Dumoulin-Smith

Analyst Certification

I, Julien Dumoulin-Smith, hereby certify that the views expressed in this research report accurately reflect my personal views about the subject securities and issuers. I also certify that no part of my compensation was, is, or will be, directly or indirectly, related to the specific recommendations or view expressed in this research report.

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Disclosures

Trending

Research Summary

Global Research Highlights (https://rsch.baml.com/r?q=RBl5jr3U2eMTI1z8yB99Pw&e=michael.dougherty%40state.or.us&h=3Vfgdg)

Stimulus Cliff?

Derek Harris 2020-Aug-21

CASE: UE 391
WITNESS: NADINE HANHAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 300

Opening Testimony
Wheeling Costs and Revenues

June 30, 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. I discuss Staff's review of wheeling costs and revenues in PGE's forecast of NVPC for its 2022 Annual Update Tariff (AUT) proceeding and to provide an update on Energy Imbalance Market (EIM) wheeling revenues.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared the following exhibits:

- Staff/301, Witness Qualifications Statement
- Staff/302, PGE's Non-Confidential Responses to Staff DRs
- Staff/303, PGE's MONET PCInputs Tab
- Staff/304, Confidential Electronic Attachment to PGE's Response to Staff DR 103
- Staff/305, Confidential Electronic Attachment to PGE Response to Staff DR 105

Q. How is your testimony organized?

A. My testimony is organized as follows:

WHEELING COSTS AND REVENUES

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

A. Staff submitted discovery and reviewed the Company's MONET inputs to understand how the Company incorporates wheeling costs into its forecast of NVPC for the AUT. Staff discovered that PGE does not include forecasted costs of short-term transmission purchases in the AUT. Rather, PGE only includes forecasts of costs related to firm, long-term transmission rights.[1] The calculation of these costs is fairly straightforward in PGE's workpapers.

The Company generally calculates wheeling costs by multiplying the applicable transmission rates by a forecast of MWs of capacity purchased. The Company also includes some other additional costs, like Scheduling, Control, and Dispatch (SCD) service costs.[2] Staff discovered that in general, the vast majority of PGE's wheeling costs come from **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[3]

Q. Please explain any major changes to the forecast of wheeling costs for the 2022 AUT.

A. BPA is currently conducting a transmission rate case that is still pending. PGE indicated in its testimony that it will incorporate the impacts of BPA's rate case

[1] Staff/302, PGE Response to Staff DR 15.
[2] UE 391 / PGE / 100, Vhora – Outama – Batzler / 45, lines 17-18.
[3] Staff/303, PGE's MONET PCInputs Tab.

into the 2022 power cost forecast. In particular, PGE estimates a rate increase of about four percent for Point-to-Point (PTP) rates and 7.6 percent for SCD service.[4] Staff was able to corroborate these percentage increases in the Company's workpapers. Staff believes it is reasonable to incorporate the BPA rate case impact on power costs into the 2022 NVPC forecast. BPA has indicated that it will not issue a record of decision on rates until late July 2021.[5] Staff will submit discovery in early August to verify any change in BPA transmission rates.

Q. Earlier in your testimony, you mentioned that you also reviewed PGE's forecast of wheeling revenues. What did you find?

A. The Company receives wheeling revenue when it resells or sells "excess" transmission capacity. The Company includes forecasted wheeling revenues in its forecast of NVPC and these revenues net against power costs.[6]

Q. How does PGE forecast wheeling revenue?

A. PGE does not forecast individual sales but assumes a fixed amount of 300 MW of capacity available for resale in Q1, Q2, and Q4 of 2022, but not Q3.[7]

Q. Why doesn't PGE forecast transmission capacity resales in Q3?

A. In testimony, PGE states that it does not assume it will have transmission capacity to sell in Q3 due to "expected transmission needs for PGE's load

[4] UE 391 / PGE / 100, Vhora – Outama – Batzler / 45, lines 17-18.
[5] *TC-22 Tariff Proceeding.* Bonneville Power Administration. Accessible at: https://www.bpa.gov/Finance/RateCases/TC-22/Pages/TC-22-Tariff-Proceeding.aspx
[6] UE 391 / PGE / 100, Vhora – Outama – Batzler / 47.
[7] UE 391 / PGE / 100, Vhora – Outama – Batzler / 47, lines 5-7.

service obligation or PGE's Market Sales Obligation."[8] The Company indicates that holding this capacity allows it to plan for potential load excursion events in Q3.[9]

Q. Please explain any changes to the transmission revenue forecast from the final NVPC forecast for the 2021 AUT.

A. In testimony, PGE explains that it increased the market price of its transmission resale transactions from $1.05/MWh to $1.50/MWh to align with average market prices in average operations.[10] The impact of this increase in price results in a reduction of power costs of about $0.9 million compared to the 2021 AUT.[11] The total reduction to power costs due to wheeling revenues is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[12]

Q. Do you have any concerns with PGE's forecast of wheeling revenues?

A. Yes. In order to check the reasoning behind the Company's approach, Staff asked why the Company assumes it will have 300 MW of excess transmission capacity to sell in Q1, Q2, and Q4, and not some other amount. The Company explained that this 300 MW amount is a legacy number based on a long-term resale agreement that expired in Q1 2018.[13] Despite the expiration of this agreement, PGE continues to model the 300 MW to forecast transmission resale revenue in the AUT.

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[8] UE 391 / PGE / 100, Vhora – Outama – Batzler / 47, lines 7-9.
[9] Staff/302, PGE Response to Staff DR 103.
[10] UE 391 / PGE / 100, Vhora – Outama – Batzler / 47, lines 15-16.
[11] UE 391 / PGE / 100, Vhora – Outama – Batzler / 47, line 18.
[12] Staff/303, PGE's MONET PCInputs Tab.
[13] Staff/302, PGE Response to Staff DR 103.

Staff asked the Company to provide historical resales and purchases of transmission, which it did. Staff found that the amount of *net sales* (that is, MW sales minus MW purchases) is close to 300 MW.[14] However, Staff does not believe using the net MW of transmission sales reveals the full picture of PGE's historical transmission revenues.

Q. Please elaborate.

A. Staff reviewed historical transmission revenues for the past five years, as well as historical MW purchased and resold. Although 300 MW may seem like a reasonable assumption for net MW resold, the costs incurred for short-term transmission purchases **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[15] Thus, using an assumption of the net amount of MWs of transmission capacity sold and purchased is not a reasonable method for forecasting the annual net revenue or costs for the transactions.

This point is illustrated below in tables showing forecasts of annual revenues and annual costs and annual volumes of short-term transmission capacity sold.

[14] Staff/302, PGE Response to Staff DR 103 and Staff/304, Confidential Electronic Attachment to PGE Response to Staff DR 103.
[15] Staff/305, Confidential Electronic Attachment to PGE Response to Staff DR 105.

Table 1 - Transmission Revenues[16]

[BEGIN CONFIDENTIAL]

Year/ Month	Short Term Purchases Cost	Actual Resales Revenue	Forecast Resales Revenue	Forecast Error (Actual Revenue – Forecast Revenue)
2016	[redacted]	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]	[redacted]
Average	[redacted]	[redacted]	[redacted]	[redacted]

[END CONFIDENTIAL]

The table below lists forecasts and actuals in MW.

Table 2 - Transmission MW[17]

[BEGIN CONFIDENTIAL]

Year	Short Term purchases (MW)	Short Term Sales (MW)	Net Short Term Sales (MW)
2016	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]
Average	[redacted]	[redacted]	[redacted]

[END CONFIDENTIAL]

Averaging the far-right column of *Table 2* shows that 300 MW may be within a reasonable range for net MW sold. However, a review of *Table 1* and the difference between the forecast of the net revenue from short-term sales and purchases and actual revenue shows that on average, the Company under

[16] Staff/305, Confidential Electronic Attachment to PGE Response to Staff DR 105.
[17] Staff/305, Confidential Electronic Attachment to PGE Response to Staff DR 105.

forecasts transmission revenues by roughly **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Q. Do you have any additional observations?

A. Yes. Staff also observed from PGE's workpapers that there appears to be no basis for **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[18] In reply testimony, the Company should provide evidence to support its assumption it will not have transmission capacity to sell in Q3.

Further, it is also unclear from the Company's workpapers whether its assumptions about the rates it charges are reasonable. The Company testified that for purposes of the 2022 NVPC forecast, it increased forecasted transmission rates from $1.05 to $1.50.[19] Staff could not verify whether the transmission prices in previous years were reasonably close to the $1.05/MWh rate mentioned in PGE's testimony. The workpapers provided to Staff contain only numbers without cell formulae intact, so Staff was unable to trace how revenues were calculated. The Company should clarify in its reply testimony how it calculates the $1.50/MWh price, and provide supporting data.

Q. As a result of your review, do you recommend an adjustment?

A. Yes. Staff believes that the Company has under forecasted revenues from wholesale sales of transmission. Staff recommends abandoning the current

[18] Staff/305, Confidential Electronic Attachment to PGE Response to Staff DR 105.
[19] UE 391 / PGE / 100, Vhora – Outama – Batzler / 47, lines 15-16.

methodology of estimating revenues as it is does not result in a reasonable forecast.

Staff proposes to base the forecast of revenue on total annual short-term sales, which is derived from the average of historical MW sold over the past five years. Staff recommends using historical sales from all hours of the year (8760), which would include third quarter sales in the forecast of wheeling revenues. Staff calculated this historical average of short-term sales to be **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[20] Despite the fact that Staff still has some questions about the $1.50/MWh charge, using this number would result in a transmission revenue forecast of **[BEGIN CONFIDENTIAL]** [redacted][21] [redacted] **[END CONFIDENTIAL]**

Q. Why do you propose basing the estimate of wheeling revenues on total sales rather than net sales?

A. As noted above, basing the estimate of revenue on the net amount of capacity sold in short-term sales does not capture the full value of the transmission sales.

Q. Why is it appropriate to include all the revenue from estimated sales without also including the costs of purchases?

[20] This average is based on the “Short Term Sales” column in *Table 2*.
[21] Staff/303, PGE’s MONET PCInputs Tab.

A. As noted above, PGE currently does not include the costs of short-term capacity purchases in its estimate of NVPC. Further, PGE is using an outdated number of 300 MW for forecasts. Staff believes that basing revenues on actual MW sales is more appropriate. Staff would also be open to a mechanism that offsets total revenues against total costs of short-term transmission transactions.

Q. Earlier in your testimony, you mentioned you would provide an update on EIM wheeling revenues. Can you elaborate?

A. Yes. In PacifiCorp's 2021 TAM proceeding, Staff voiced a concern that EIM entities that facilitate wheeling power, such as PacifiCorp and PGE, do not currently receive any benefit for doing so. Staff indicated it would continue to monitor this issue and is doing so in this case.[22]

Staff submitted discovery requests asking that PGE 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 compensation.[23] PGE reports that this process could assess whether there would be a potential future need for a market solution to address the equitable sharing of wheeling benefits.[24] However, PGE also explained that "CAISO has prioritized summer readiness-related policy issues for approximately the past eight months. Therefore, policy initiatives that may address

[22] UE 375 - Staff/200, Enright/47-49.[23] Staff/302, PGE Response to Staff DR 12.
[23] Staff/302, PGE Response to Staff DR 12.
[24] Staff/302, PGE Response to Staff DR 12.

wheeling compensation in the EIM have effectively remained "on hold" while CAISO addresses summer readiness-related policy topics."[25]

Staff intends to continue to monitor the developing issue of EIM or EDAM wheeling revenues.

Q. Does this conclude your testimony?

A. Yes.

[25] Staff/302, PGE Response to Staff DR 12.

CASE: UE 391
WITNESS: NADINE HANHAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 301

Witness Qualifications Statement

June 30, 2021

WITNESS QUALIFICATIONS STATEMENT

NAME:	Nadine Hanhan
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Analyst, Transmission & Distribution Energy Resources and Planning Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	Bachelor of Arts in Economics, CSUSB (2010) Bachelor of Arts in Philosophy, CSUSB (2010) 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. 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, UE 390, UM 1810, UM 1811, UM 1815, UM 1846, UM 1847, and UM 2031.

CASE: UE 391
WITNESS: NADINE HANHAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 302

Exhibits in Support
Of Opening Testimony

June 30, 2021

May 7, 2021

TO: Steve Storm
Public Utility Commission of Oregon

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC COMPANY
UE 391
PGE Response to OPUC Data Request No. 012
Dated April 23, 2021

Request:

Staff notes that when the Company facilitates a wheel through in EIM, it receives no direct financial benefit, as only the sink and source BAA directly benefit from the wheel through.[1]

a. If the Company has engaged with CAISO regarding this matter, please provide a summary of the content of those communications to date.
b. If the Company has conducted any 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 any 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:

a. CAISO is engaged with EIM Entities on this topic. Resulting from CAISO's Consolidated Energy Imbalance Market Initiative (which concluded in the fall of 2017), CAISO committed to monitor net wheeling (which CAISO does in its EIM quarterly benefit reports). See pages 7 and 8 of CAISO's Draft Final Proposal for additional background on wheeling benefits in EIM.

   http://www.caiso.com/Documents/DraftFinalProposal-ConsolidatedEnergyImbalanceMarketInitiatives.pdf

   As part of CAISO's Extended Day-Ahead Market Initiative, CAISO intends to address wheeling compensation and has proposed that wheeling compensation mechanisms

[1] EIM Quarter 1 2020 EIM benefits report. Accessible at: https://www.westerneim.com/Documents/ISO-EIMBenefitsReportQ1-2020.pdf.

resulting from the Extended Day-Ahead Market Initiative could also be considered to address wheel through compensation in the EIM.

PGE notes that CAISO has prioritized summer readiness-related policy issues for approximately the past 8 months. Therefore, policy initiatives that may address wheeling compensation in the EIM have effectively remained "on hold" while CAISO addresses summer readiness-related policy topics.

b. PGE has not conducted an analysis of EIM wheel through in its territory. However, wheel through volumes are tracked by the CAISO. CAISO reports wheel through volumes by EIM Entity in its quarterly benefit reports. The reports are available at CAISO's Western EIM website: https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx

c. PGE has not conducted an analysis quantifying the value lost, if any, due to EIM wheel throughs in its Balancing Authority Area (BAA).

   In general, PGE has largely been an importer of energy in the EIM, and PGE has experienced relatively low volumes of wheel through to-date.[2] CAISO's market model objective is to reduce the cost for the entire market footprint subject to unit constraints, transmission constraints, etc. In order to "sink" more energy into PGE's BAA (i.e., reduce wheel through), PGE would likely need to increase its bids on resources that no longer reflect PGE's best assessment of cost. If bids are greater than PGE's best assessment of cost, it is possible that wheel through would be reduced, but PGE would incur uneconomic market instructions to do so.

d. The EIM Entities (which includes PGE) have jointly presented on transmission elements of an Extended Day-Ahead Market (EDAM) Design, including wheeling. The EIM Entities presented on the topics during a CAISO meeting under its EDAM Initiative on February 11 and 12, 2020. The CAISO's EDAM Initiative is in its early stage(s), and discussions at the February 11 and 12 workshops were effectively "first steps" towards the formation of CAISO policy proposals.

   The presentation can be accessed via the following link:

   http://www.caiso.com/InitiativeDocuments/Presentation-ExtendedDay-AheadMarket-TransmissionProvision-EIMEntities.pdf

[2] An exception to PGE's position as a net importer was 2020 when PGE was a net exporter in Q2 and Q3 2020. However, throughout 2020 wheel through volumes remained low.

May 7, 2021

TO: Nadine Hanhan
Public Utility Commission of Oregon

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC COMPANY
UE 391
PGE Response to OPUC Data Request No. 015
Dated April 23, 2021

Request:

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

a. How does PGE forecast these purchases in its annual power cost update?
b. Please explain how this affects power costs.
c. What is the total cost of these purchases? Please reference the appropriate workpapers in your answer if available, with cell formulae intact.
d. If these purchases are not reflected in power costs, please explain why they are not included.

Response:

a. PGE does not include estimated costs associated with short term transmission purchases in the NVPC forecast. PGE only incorporates in the NVPC forecast costs related to firm, long-term transmission rights. However, PGE does incur costs related to short term transmission purchases. Attachment 015-A provides historical costs and revenues associated with short term transmission purchases and resales between 2010 and 2020.
b. Short term transmission purchases do not impact PGE's NVPC forecast. .
c. Please see the response to part a.
d. PGE does not include an estimate for short term purchases in the NVPC forecast because:
    - PGE does not have a firm agreement for short term transmission purchases;
    - PGE plans both generation and transmission on a long-term basis to meet projected peak load obligations. As such, from a planning perspective, PGE does not forecast short-term transmission purchases.

Attachment 015-A is protected information subject to Protective Order No. 21-099.

June 10, 2021

TO: Nadine Hanhan
Public Utility Commission of Oregon

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC COMPANY
UE 391
PGE Response to OPUC Data Request No. 103
Dated May 27, 2021

Request:

Please refer to PGE / 100 Vhora – Outama – Batzler / 47, lines 6-7. The Company indicates that it reserves a fixed 300 MW transmission capacity for resale.

a. Please explain why the Company selected 300 MW.
b. Has 300 MW always been used as a placeholder for transmission capacity in the AUT? If not, please explain why. If so, please explain why.
c. Please provide the historical data of actual numbers for the past five years for this number if available.

Response:

a. PGE proposed transmission resale modeling in our 2015 NVPC filing (UE 283) pursuant to Commission Order No. 13-280 adopting a stipulation between parties in Docket No. 266 (2014 AUT). The modeling is based on an agreement between stipulating parties in Docket No. UE 266 providing that beginning with its 2015 NVPC filing, PGE would include a proposed forecast of transmission resale revenue. Consequently, starting with the 2015 NVPC forecast, PGE has been including transmission resales revenues in the MONET modeling.

   The transmission resale modeling was initially based on a long-term resale agreement with a counterparty for 300 MW capacity of transmission that expired in Q1 2018. Although the agreement expired, PGE continued to model 300 MW transmission available for resale in Q1, Q2, and Q4 net of short-term transmission purchases as a reasonable and prudent amount that PGE can resell on a short-term basis without impacting PGE's system reliability and planning for load excursion events. As provided in Attachment 103-A, the short-term transmission resales net of short-term transmission purchases are close to 300 MW in recent years.

b. Yes, since first including transmission resale revenues in the 2015 NVPC forecast based on the agreement mentioned in part a, PGE assumed 300 MW transmission would be available for resale, net of short-term transmission purchases. And for reasons stated in part (a), we continue to believe this amount represents a reasonable and prudent amount to forecast, without impact to PGE's operations.

c. Please see Attachment 103-A, column F for annual MW of transmission resales net of short-term transmission purchases.

Attachment 103-A is protected information subject to Protective Order No. 21-099.

June 10, 2021

TO: Nadine Hanhan
Public Utility Commission of Oregon

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC COMPANY
UE 391
PGE Response to OPUC Data Request No. 105
Dated May 27, 2021

Request:

Regarding wheeling sales:

a. Please provide the dollar amount of PGE's **forecasted** sales in the past 5 years. Please provide the MW values of sales, as well as total revenues in dollars. Please also provide this information on a monthly basis.

b. Please provide the **actual** amount of PGE's sales in the past 5 years. Please provide the actual MW values of sales, as well as total sales in dollars. Please also provide this information on a monthly basis. This is an ongoing request.

Response:

a. Attachment 105-A, tab "Forecast Transmission Resales" provides PGE's forecast of transmission resale revenues between 2016 and 2021.

b. Attachment 105-A, tab "Actual MW ST net resales" provides monthly MWh and MW of short-term transmission resales and purchases and associated costs and revenues between January 2016 and through December 2020.

Please note that in actual operations PGE does not have a secured long-term transmission resale agreement and all transmission resales are pursued on a short-term basis (less than one year). Often this represents an instrument to optimize PGE's transmission needs to reliably serve our load and is based on the economics of PGE's generation plants. For example, PGE would pursue transmission resales in the event a plant is placed in an extended forced outage, if the transmission wasn't needed for replacement power. In that case PGE would incur significant costs for replacement power that would potentially more than outweigh the transmission resale revenues.

The transmission resale market is very illiquid and there is no guarantee that there will be demand for resale within the year. Operationally there are significant constraints that Power Operations must consider before reselling transmission such as outages, protecting constrained paths, economics of plant dispatch, load excursions, etc.

Attachment 105-A is protected information subject to Protective Order No. 21-099.

CASE: UE 391
WITNESS: NADINE HANHAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 303

Exhibits in Support
Of Opening Testimony

June 30, 2021

Confidential Staff Exhibit 303

is filed in electronic format

and subject to Protective Order 21-099

CASE: UE 391
WITNESS: NADINE HANHAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 304

Exhibits in Support
Of Opening Testimony

June 30, 2021

Confidential Staff Exhibit 304

is filed in electronic format

and subject to Protective Order 21-099

CASE: UE 391
WITNESS: NADINE HANHAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 305

Exhibits in Support
Of Opening Testimony

June 30, 2021

Confidential Staff Exhibit 305

is filed in electronic format

and subject to Protective Order 21-099

CASE: UE 391
WITNESS: BRIAN FJELDHEIM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 400

Opening Testimony

June 30, 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. I describe Staff's position on the following issues related to PGE's forecast of 2022 NVPC: Natural gas pricing (including transport and storage costs), gas and storage optimization, and the Beaver modernization project.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared the following exhibits:

Staff/401 Witness Qualification Statement.
Staff/402 Gas Costs - Comparison of 2021 to 2022 AUT.
Staff/403 MONET Gas Storage Injection and Withdrawals.
Staff/404 MONET Gas Storage Optimization – 2021 vs 2022 AUT.
Staff/405 Beaver Plant Upgrade.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. NATURAL GAS PRICING (INCLUDING TRANSPORTATION AND STORAGE COSTS)

Q. Please summarize Staff's review of Portland General Electric Company's (PGE or Company) natural gas pricing including transportation and storage costs in the 2022 power cost Annual Update Tariff (AUT) filing

A. Staff's review focused primarily on portions of testimony and supporting exhibits provided by Ms. Vhora, Mr. Outama, and Mr. Batzler addressing updated natural gas, transportation, and storage cost inputs used in the Company's Net Variable Power Cost (NVPC) MONET model.[1]

Q. Please describe the change in PGE's natural gas expense between the 2021 and the 2022 AUT filing.

A. In the initial 2022 AUT filing, the Company projects natural gas costs will increase **[BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL]**[2] over the forecast costs in the final MONET run of the 2021 NVPC. The increased gas expense is due to two factors: **[BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL]** gigawatt hours (GWh) of additional natural gas thermal generation, a **[BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL]** increase over the final 2021 NVPC forecast and higher natural gas prices, as shown in Confidential Figure 1 on the following page. On a per megawatt hour (MWh) basis, PGE's projected

[1] PGE/100-105, Vhora – Outama – Batzler.
[2] Staff/402, Fjeldheim/2.

2022 AUT natural gas expense is increasing by **[BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL]**. Figures 1-3 are graphs showing the change in natural gas expense created by Staff using data provided in PGE's confidential response to Staff DR 42.[3]

Figure 1 – Forecasted Gas Generation (MWh)

[BEGIN CONFIDENTIAL [redacted]

END CONFIDENTIAL]

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[3] *Id.*

Figure 2 – Forecasted Gas Expense ($)

[BEGIN CONFIDENTIAL

[redacted]

END CONFIDENTIAL]

Figure 3 – Forecasted Gas Price – ($) Per MWh

[BEGIN CONFIDENTIAL

[redacted]

END CONFIDENTIAL]

Q. Did PGE illustrate the change in gas generation, expense, and price data in the same manner as Figures 1-3?

A. No. In Table 5 found at PGE/100, Vhora – Outama – Batzler / page 56, the Company illustrates a gas generation cost decline of $11.2 million from the 2021 final updated MONET run for the 2022 test year.[4] Staff used information PGE provided in discovery, to compare gas generation output, gas cost, and the average price point per MWh between the 2021 and the 2022 AUT filings. On this basis, Staff calculated natural gas expenses are increasing $43.6 million (26.6 percent) over the 2021 AUT.[5] To ensure the accuracy of Staff's methodology, Staff also cross-referenced the other non-gas outputs used in PGE's Table 5. Staff agrees with PGE's NVPC increase of $53.9 million, there is just a difference between Staff's calculations and PGE's Table 5. Please see Staff/402 for further clarification of Staff's analysis of PGE's Table 5.

Q. What data source(s) does PGE use for pricing natural gas in the 2022 AUT?

A. The Company used its gas forward price curve dated as of February 26, 2021, to derive the natural gas prices used in the 2022 AUT.[6] In this filing, natural gas forward pricing is based upon 12 months of gas pricing from the

[4] PGE/100, Vhora – Outama – Batzler/56 at line 10.
[5] Staff/402, Fjeldheim.
[6] PGE Confidential workpaper – Vol 1, Excel file "#2022EndurCurves-20210226_FA" and Non-confidential workpaper – Vol 1, Word file "^_2022AUTElectricAndGasCurves"

[BEGIN CONFIDENTIAL [redacted] **END CONFIDENTIAL]** natural gas hubs.[7]

Based upon Staff's ongoing review of natural gas futures pricing conducted as part of the annual purchased gas adjustment (PGA), the Company's forecasted 12 month forward gas pricing appears to be within the projected forward pricing ranges used by Oregon's regulated gas utilities.

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

A. No. Staff finds the Company's natural gas price forecast to be reasonable.

[7] *Id.*

ISSUE 2. GAS AND STORAGE OPTIMIZATION

Q. What is gas optimization?

A. Gas optimization can be done in a number of different ways. One method 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 and fueling 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 type of gas optimization commonly used?

A. Yes. Another type 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. Additionally, if a utility has the means to store gas throughout the year, the utility may purchase gas during times of the year when gas demand declines and prices fall and use or sell it later when gas demand increases and prices rise.

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. In this case, 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, there is a line between optimization and speculation. If a utility purchased gas solely for the purpose of later reselling it at a higher price and does not intend to use it to serve customer load, this is speculation and could 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 must 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, it is reasonable for the utility to sell the remaining generating capacity and/or unused fuel into the market for the economic benefit of the utility and ratepayers.[8]

[8] 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

Q. Does PGE engage in natural gas storage optimization?

A. Yes. The Company states:

> In the 2021 AUT, PGE proposed a method to capture potential natural gas storage optimization benefits that could be realized based on North Mist storage injection and withdrawal cycles relative to forward gas prices at the Sumas and Rockies markets and the economic dispatch of the Port Westward/Beaver complex.[9] More specifically, in order to determine a potential gas storage optimization monetary benefit, PGE first evaluated a weighted average cost of gas (WACOG) in storage based on inventory levels and market prices, and planning for gas storage injections in months when the natural gas market prices are cheaper. PGE then withdrew gas from storage during months when natural gas market prices are higher, capturing the economic benefits from running the PW/Beaver complex on cheaper natural gas.[10]

Q. What benefit will ratepayers receive from gas and storage optimization?

A. Based on the Company's initial 2022 AUT filing, ratepayers will receive a gas storage financial benefit of \$4.2 million and a gas resale benefit of \$0.2 million.[11] Staff confirmed these figures via PGE's 2022 AUT MONET model.[12]

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[9] PGE 2021 AUT docketed as UE 377, Commission Order 20-392 at pages 6-7.
[10] PGE/100, Vhora – Outama – Batzler/pages 31-32.
[11] PGE/100, Vhora – Outama – Batzler/page 34 at lines 1-3.
[12] PGE Confidential workpaper – Excel file "#2022 AUT-00l", Tab "PC Input"; Tab "Gas Resale", rows 26-28; and Tab "Gas Storage", rows 280-282.

Q. Did Staff note any concerns or inconsistencies in the 2022 AUT MONET model?

A. Staff noted two issues. First, in the 2022 AUT MONET model, Excel Tab "Gas Storage,"[13] MONET shows **[BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL]**. Staff asks that the Company explain whether the storage **[BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL]** is correct in the MONET gas storage tab, and what impact, if any, this has on ratepayers. Staff also notes that **[BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL]** planned monthly injection/withdrawal cycle and no indication of maintenance de-rate for the month. Staff asks PGE to respond with an explanation why the MONET gas storage tab does not model **[BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL]**.

Second, Staff's comparison of workpapers from the 2021 and 2022 AUTs shows that in the 2021 AUT MONET model, PGE included a reduction to power cost for **[BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL]**[14] while in the 2022 AUT MONET model, the entry for **[BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL]** is

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[13] Confidential Staff/403.
[14] Confidential Staff/404 – Excerpt of 2021 AUT gas costs from PGE's Excel file "UE 391_OPUC 042_Attach A_CONF", Tab" 2020.11.15_PwrCsOut".

omitted.[15] Per PGE/100, Vhora – Outama – Batzler / page 34 at lines 1-3, the Company indicates ratepayers will receive a $4.2 million gas storage optimization benefit.

Q. Does Staff propose an adjustment for gas and storage optimization in this round of testimony?

A. Yes. Staff recommends a $4.2 million reduction to NVPC to account for the omitted value.

[15] *Id., Tab "2021.4.1_PwrCsOut".*

ISSUE 3. BEAVER MODERNIZATION PROJECT

Q. What is the Beaver modernization project?

A. The Company states:

> The Beaver Modernization Project will upgrade the existing Beaver gas turbine combustion systems from a dual fuel system to a single fuel dry low NOx system to reduce the overall emissions for the plant as turbines are upgraded. The single fuel will be natural gas and the upgraded units will be prevented from operating on fuel oil as an alternative. The combustion upgrade will allow for greater operational flexibility while meeting PGE's commitment to reduced emissions at the site.[16]

Q. Is the Beaver modernization project a required or voluntary undertaking?

A. The upgrade to Beaver Unit 6 appears to be voluntary. The Company states:

> In June 2020, PGE made a voluntary commitment to the Oregon Department of Environmental Quality (DEQ) to reduce annual allowable emissions of Regional Haze pollutants at the Beaver Plant to support DEQ's Regional Haze second planning period. Environmental regulations and standards have become more stringent over time, as has the expectations of customers about PGE's environmental impact and stewardship. Current emissions from the Beaver turbines remain similar to the emissions rates when originally converted to allow combustion of natural gas in the 80's. Post project emissions will be significantly lower and more aligned with modern turbine emissions.[17]

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[16] PGE/100, Vhora – Outama – Batzler/47-48.
[17] PGE/100, Vhora – Outama – Batzler/48, lines 5-13.

However, in PGE's response to Staff DR 110(d), the Company states:

> The combustor upgrade project at PGE's Beaver facility is primarily driven by *air quality requirements* [Staff emphasis]. In evaluating its options, PGE reviewed what would be required at Beaver to meet and manage those requirements for the current facility. The combustor upgrades allow PGE and customers to make continued use of the Beaver facility and bring the facility into alignment with current air quality requirements, which also aligns with PGEs goals for a clean energy future. PGE anticipates the significantly reduced NOx[18] emissions will meet the limits in current EPA performance standards and, with a more modern emissions profile, prepare the site for future regulatory changes.[19]

Q. How does the Beaver modernization project reduce the 2022 NVPC by $60,000?

A. The Company states:

> The 2022 NVPC forecast is declining by approximately $60,000 per the Beaver upgrade based on the MONET model's algorithm to minimize total NVPC. The model minimizes power costs by economically dispatching plants and making market purchases and sales to meet customer loads. Thus, the increased generation from the Beaver upgrade also triggers changes to the market purchases and sales. The value of the additional generation against the market electric prices results in increased market sales and decreased market purchases, which provides a net reduction to total power costs.[20]

[18] NOx = Nitrogen oxide.
[19] Staff/405, pages 1-2.
[20] *Id., page 3.*

Q. Does Staff propose an adjustment related to PGE's Beaver modernization project?

A. No.

Q. Does this conclude Staff's testimony?

A. Yes.

CASE: UE 391
WITNESS: BRIAN FJELDHEIM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 401

Witness Qualifications Statement

June 30, 2021

WITNESS QUALIFICATION STATEMENT

NAME:	Brian Fjeldheim
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Financial Analyst Energy Rates, Finance and Audit Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	Bachelor of Science, Business Accountancy Regis University, Denver, CO Bachelor of Science, Aviation Technology Metropolitan State College of Denver, Denver, CO
EXPERIENCE:	I have been employed as a Senior Financial Analyst by the Oregon Public Utility Commission since May of 2018 in the 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. 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 391
WITNESS: BRIAN FJELDHEIM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 402

Exhibits in Support
Of Opening Testimony

June 30, 2021

May 10, 2021

TO: Healther Cohen
Public Utility Commission of Oregon

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC COMPANY
UE 391
PGE Response to OPUC Data Request No. 042
Dated April 26, 2021

Request:

In PGE/100, Vhora – Outama – Baltzer/1 PGE states that its NVPC forecast is driven by "an increase in costs associated with market purchases due to a 78 MWa load increase in 2022". Please provide the data demonstrating these purchases and their corresponding MWa in electronic spreadsheet(s) with all cell references and formulae intact.

Response:

Please see the confidential work paper in support of Table 5 included in PGE Exhibit 100, that submitted with PGE's initial filing. PGE is also attaching the work paper to this response as Attachment 042-A.

The work paper provides an analysis to compare PGE's final 2021 NVPC forecast established in UE 377 with PGE's initial 2022 NVPC forecast.

The load forecast in MWa for 2022 and 2021 is provided in tab "Comparison", cells H27 and L27, respectively. The cost impact associated with the expected increase in load is provided in cell F51, including formulae.

Attachment 042-A is protected information subject to Protective Order No. 21-099.

STAFF EXHIBIT 402, PAGE 2

IS CONFIDENTIAL AND SUBJECT TO

PROTECTIVE ORDER NO. 21-099

Excerpt from PGE's response to Staff DR 042 - Confidential Attachment 042-A

[redacted]

May 13, 2021

TO: Heather Cohen
Public Utility Commission of Oregon

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC COMPANY
UE 391
PGE Response to OPUC Data Request No. 045
Dated April 29, 2021

Request:

Regarding Table 5 in PGE/100, Vhora – Outama – Batzler/56:

a. Please provide the electronic spreadsheet(s) underlying each factor (example: Hydro Cost and Performance and $ Effect, Coal Cost and Performance and $ Effect, etc), with all cell references and formulae intact.

b. Please reconcile each amount with the amounts found in PGE Confidential Worksheet #2022 AUT-001 tab PwrCsOut.

Response:

a. Please see PGE's response to OPUC Data Request No. 042, Attachment 042-A.

b. The worksheet "PwrCsOut" from the 2022 MONET output is used in the analysis provided in Attachment 042-A.

STAFF EXHIBITS 403 AND 404

ARE CONFIDENTIAL AND SUBJECT TO

PROTECTIVE ORDER NO. 21-099

CASE: UE 391
WITNESS: BRIAN FJELDHEIM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 403

Exhibits in Support
Of Opening Testimony

June 30, 2021

PGE 2022 AUT MONET model, Excel file "#2022 AUT-00l", Tab "Gas Storage", rows 32-49.

[redacted]

CASE: UE 391
WITNESS: BRIAN FJELDHEIM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 404

Exhibits in Support
Of Opening Testimony

June 30, 2021

[redacted]

CASE: UE 391
WITNESS: BRIAN FJELDHEIM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 405

Exhibits in Support
Of Opening Testimony

June 30, 2021

June 11, 2021

TO: Brian Fjeldheim
Public Utility Commission of Oregon

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC COMPANY
UE 391
PGE Response to OPUC Data Request No. 110
Dated May 28, 2021

Request:

Please refer to PGE/100, Vhora – Outama – Batzler/47-48. Regarding the Company's voluntary decision to upgrade all Beaver gas turbine combustion systems to single fuel natural gas:

a. Please provide a schedule of the planned combustion system upgrades to the Beaver complex, to include specific timelines for each turbine and the estimated cost to upgrade each turbine.
b. How does PGE plan to depreciate the Beaver combustion system upgrades?
c. How long does PGE plan to keep the Beaver complex in operation?
d. Based on the age and relative inefficiency of the Beaver complex, how did PGE determine that upgrading these turbine is prudent and in ratepayers best interests?

Response:

a. Please see PGE's response to AWEC Data Request No. 012 with Attachment 012-A.

b. Beaver plant additions are depreciated based on depreciation parameters approved in PGE's recent depreciation studies. The most recent depreciation study (Docket No. UM 1809) provides for a December 31, 2030 depreciation schedule for the Beaver plant which is based on the plant's probable retirement date. However, PGE is currently undergoing an updated depreciation study (Docket No. UM 2152) that updates the Beaver depreciation schedule to December 31, 2035.

c. PGE does not currently have plans to cease operations at Beaver generating plant or any individual units. The plant is expected to be fully depreciated in 2035.

d. The combustor upgrade project at PGE's Beaver facility is primarily driven by air quality requirements. In evaluating its options, PGE reviewed what would be required at Beaver to meet and manage those requirements for the current facility. The combustor upgrades allow PGE and customers to make continued use of the Beaver facility and bring the facility into alignment with current air quality requirements, which also aligns with PGEs goals for a clean energy future. PGE anticipates the significantly reduced NOx emissions will meet the limits in current EPA performance standards and, with a more modern emissions profile, prepare the site for future regulatory changes.

While the Beaver facility is not PGE’s most efficient natural gas facility in terms of heat rate, it provides approximately 500MW of peaking capacity with a higher degree of flexibility when compared to traditional peaking units. The facility is not yet fully depreciated and has at least 15 years of useful life, remaining part of PGE’s portfolio until 2035. With Boardman ceasing operations, Beaver is likely to see more run time, and Beaver will remain an important asset to PGE for implementing our renewable portfolio due to its operational flexibility. Additionally, the Beaver GT rotors have approximately 70,000 hours of run time, with 200,000 hours generally regarded as end of operational life, leaving substantial operational life remaining on the rotors. Beaver will continue to require major maintenance to ensure reliable operation during times of peak demand. The plan to address this maintenance is part of the ongoing Beaver Enhanced Maintenance Plan, provided in PGE’s response to AWEC Data Request No. 012, Attachment 012-A.

The combustor upgrades and other major maintenance represent a least-cost approach given readily available alternatives (shut-down, full re-power, full replacement).

PGE notes that the combustor upgrade project is being done in phases to ensure the technology is capable of performing to the necessary requirements before fully deploying, to minimize customer impacts, and to allow for time for the scope/timing of work to evolve or be modified, if necessary. PGE is also engaging a third-party to conduct a life-span assessment of Beaver to determine possible longer-term options for the plant given its age, PGE’s need for reliable capacity, and the transition to a clean energy future. The combustor upgrade is driven by the need to manage air quality requirements at the facility and are not a result of seeking to increase the efficiency/economics of the plant.

June 11, 2021

TO: Brian Fjeldheim
Public Utility Commission of Oregon

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC COMPANY
UE 391
PGE Response to OPUC Data Request No. 111
Dated May 28, 2021

Request:

Please refer to PGE/100, Vhora – Outama – Batzler/48 at lines 17-23. Regarding the Beaver upgrade and the resultant change to plant parameters, if capacity and heat rate are both increasing, how is the 2022 NVPC forecast declining by $60,000? For example, a plant with an increasing heat rate implies the unit cost of energy output will be more expensive and a capacity increase implies more energy can be produced at the higher unit rate. In the Company's response, please provide a detailed explanation why the 2022 NVPC forecast appears to be moving inversely to the heat rate and capacity increase.

Response:

The 2022 NVPC forecast is declining by approximately $60,000 per the Beaver upgrade based on the MONET model's algorithm to minimize total NVPC. The model minimizes power costs by economically dispatching plants and making market purchases and sales to meet customer loads. Thus, the increased generation from the Beaver upgrade also triggers changes to the market purchases and sales. The value of the additional generation against the market electric prices results in increased market sales and decreased market purchases, which provides a net reduction to total power costs.

CASE: UE 391
WITNESS: KATHY ZARATE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 500

Opening Testimony

June 30, 2021

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

A. My name is Kathy Zarate. I am a Utility Analyst 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. My testimony provides Staff's review of the three issues: PGE's forecast of costs for Qualifying Facilities (QF), Standard Inputs, and PGE's Headwater Benefits Study.

Q. Did you prepare an exhibit for this testimony?

A. Yes. I prepared the following Staff exhibits:

- Exhibit Staff/501: Witness Qualification Statement
- Exhibit Staff/502: PGE's Non-confidential Reponses to Staff DR 56 and 57
- Exhibit Staff/503: PGE's Confidential Responses to Staff DR 58-A

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. QUALIFYING FACILITIES

Q. Please discuss Qualifying Facilities (QFs) and how the costs are treated in the Automatic Update Tariff (AUT).

A. QFs are small power producers whose output must be purchased by investor-owned utilities at rates established by the respective public utility commissions. QF-related power purchase costs are recovered through PGE's Annual Update Tariff and Power Cost Variance Mechanism in two different ways. First, the test year forecast for the AUT includes a forecast of QF-related power purchase costs. Second, the AUT process includes a track and true-up adjustment in which the variance between forecasted costs for "new" QFs and the actual costs is separately tracked and passed directly to ratepayers as a credit or charge. For purposes of this mechanism, new QFs are those that are scheduled to come on-line during the forecasted test year or after the test year forecast is finalized.

Q. Are there any other adjustments in the AUT related to QFs?

A. PGE's 2018 AUT proceedings, parties stipulated that PGE should "derate" the forecast of costs for new QFs to account for the uncertainty as to whether they would actually come on-line during the forecast year. The energy derate was based on a ratio of the most recent four-year historical average of actual versus forecasted new QF-related costs.

Q. Did PGE perform this derate for its 2022 NVPC forecast?

A. No, it did not. PGE testified that the four-year average of actual costs for new QFs exceeds the four-year average of the forecasted costs, and accordingly, PGE did not derate the forecasted NVPC for new QFs for 2022.

Q. Please summarize your recommended adjustment related to PGE's forecast of QF costs.

A. I have no adjustment to PGE's forecast. With respect to the QF derate issue, I agree with PGE that no adjustment is needed because the four-year average of actual costs for new projects exceeds the four-year average of forecasted costs over the most recent four-year history of 2017-2020.

Q. Please discuss the QF cost tracking methodology.

A. The Commission adopted the track and true-up adjustment in Order No. 18-405, which was issued in PGE's 2017 general rate case. Under Order No. 18-405, PGE updates forecasted costs for new QFs up and until the final MONET update in November of year preceding the forecast year, based on known changes to scheduled CODs for new QFs. During the forecast year, PGE tracks the actual CODs for new QFs and defers the difference between actual new QF costs and forecasted new QF costs to recover or credit the variance related to changed CODs in the next power cost proceeding. Section 3 d. of the stipulation adopted by the Commission describes how the variance is determined:

> *……the variance to be refunded or collected from customers will be determined by re-running the final*

November 15 NVPC MONET forecast and replacing the estimated QF CODs with actual recorded CODs.[1]

Unlike any other variance between actual and forecasted costs in the AUT, the variance tracked in the New QF track and true-up mechanism is not subject to the deadband and sharing bands of the NVPC.

Q. Did PGE follow the methodology in Order No. 18-405 with regards to this filing?

A. Yes.

Q. What did the PGE tracking study find?

A. The tracking study found a $1.9 million adjustment for the benefit of customers. PGE notes that the credit to customers included in the 2021 NVPC was $3.3 million, so customers will actually face an increase of $1.4 million in net power cost associated with the tracking methodology when compared to current PGE power costs.[2]

Q. Did you verify PGE's calculations?

A. Yes, I verified the Company's calculations by reviewing PGE's work papers.[3]

Q. Is PGE proposing any changes to the new QF track and true–up mechanism in this filing?

A. No. The Company believes the current mechanism provides the simplest, most straightforward, and most precise methodology.[4]

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1. Order No. 08-405, App. A, p. 3.
2. UE 391/PGE/100, Vhora-Outama-Batzler/41.
3. UE 391 work paper Attachment 1_Confidential MFRs\Vol 9 - Enhancements and New Items\Step 00e - 2020 QF Tracker.
4. UE 391/PGE/100 Vhora – Outama – Batzler/40.

Q. Does Staff have any recommendations with respect to PGE's proposal?

A. Yes. Staff, continues to agree with the Company proposal for tracking the differences in the actual and projected CODs.

ISSUE 2. STANDARD INPUTS

Q. Please summarize this issue.

A. Standard inputs refer to various cost items associated with the production of power costs in operating power plants and other sources of power. The standard inputs reviewed for this testimony are forced outages, scheduled maintenance outages, heat rates, natural gas price forecast, Official Forward Price Curve (OFPC), fuel prices, and minimum operating levels.

Q. Please discuss forced outage rates.

A. PGE provided information regarding its calculation of forced outage rates in its May 10, 2021, filed workpapers. The forced outage rates are also referenced in PGE's response to Staff DR 57, a copy of which is attached as Staff/502. After reviewing the workpapers and data request response information, Staff finds the forced outage rates to be reasonable and based on a four-year moving average, consistent with Commission direction as established in Order No. 10-414.

Q. Please discuss scheduled maintenance outages.

A. PGE's response to Staff DR 57 also provides information on scheduled maintenance outages. Graph 1 below displays the actual and scheduled maintenance for the major thermal generating plants for the time period 2018 through 2021.

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL].

Q. What does Graph 1 above say to you?

[BEGIN CONFIDENTIAL]

A. [redacted]

[END CONFIDENTIAL]

Q. Do you have any concerns about the [redacted] Plant outage?

[BEGIN CONFIDENTIAL]

A. [redacted]

[END CONFIDENTIAL]

Q. Did your review of scheduled maintenance raise any concerns?

A. No. In Staff DR 56, a copy of which is attached as Exhibit Staff/502, I asked for information regarding the factors PGE considers in developing maintenance schedules, including the timing of when maintenance occurs. PGE's response identified several factors it considers in scheduling maintenance:

Outages are scheduled to minimize costs and include consideration for:

- Replacement power costs,
- Labor costs and requirements,
- Long Term Service Agreements (LTSA),
- Forecast operation of the unit until the next scheduled outage window, and
- PGE's system needs for energy, capacity and operating range.

I believe PGE's considerations are appropriate and have no concern in this area.

Q. Did you review the filed heat rates for PGE thermal plants?

A. Yes. The heat rates forecasted for the 2022 test year appear in PGE's workpapers.[5] I have reviewed those heat rates and they seem reasonable. I reviewed heat rates for PGE's thermal plants for CYs 2016, 2017, 2018, and 2019, and found the heat rates for 2021 do not depart from prior heat rates. A copy of the heat rates I reviewed is attached as Exhibit Staff/503.[6]

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5. UE 391 PGE\Workpapers\Attachment 2_Public MFRs
6. Staff/503, UE 391 PGE Confidential Response Staff DR 58.a.

Q. Are there Minimum Filing Requirements (MFRs) associated with this filing?

A. Yes. The MFRs define the documents PGE must provide to parties in conjunction with PGE's initial AUT filing. Order No. 08-405 includes the list of Commission adopted MFRs for PGE to follow whether it files a stand-alone update to its NVPC or an update in a General Rate Case (GRC) filing.[7] In addition, the Company is subject a new requirement in Order No. 20-321, issued Sept 29, 2020. PGE has to submit a report detailing the Wheatridge facility as part of its annual power cost filing.

Q. Do you have any concerns regarding PGE's compliance with the MFRs?

A. No.

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7. Order No. 08-405, App. A, pp. 11-14.

ISSUE 3. HEADWATER BENEFITS STUDY

Q. What is the Headwater Benefits study?

A. PGE testifies that under the Pacific Northwest Coordination Agreement (PNCA), the Northwest Power Pool (NWPP) conducts an 80-year regulation study called the Headwater Benefits Study (HBS) based on a regulation model whose objective function is to maximize the firm energy load-carrying capability of the Northwest system as a whole.[8] This model considers the loads and thermal resources of regional entities, as well as hydro resources. The model produces a simulated regulation of 80 water years under historical stream flows, which PGE then uses, with a set of adjustments, to develop the average hydro energy inputs to MONET.[9]

Q. Did PGE use the most recent HBS to determine the average hydro energy inputs to MONET for the 2022 NVPC forecast?

A. No. PGE states that it believes there is a material error in the study regarding the Mid-C operations in the most recent study. PGE states that it is investigating the issue and plans to supplement the record in the July MONET update.[10]

Q. Do you think it is acceptable to wait until July with regards to this issue?

A. Yes, given that PGE believes there is a material error involved, I do not see any other viable option at this time. The Mid-C dams are a significant

8. PGE/100, Vhora-Outama-Batzler/38.
9. PGE/100, Vhora-Outama-Batzler/39.
10. PGE/100, Vhora-Outama-Batzler/39.

generation source and should be modeled correctly. However, if the HBS changes as a result of PGE's activity in this regard, that would likely change PGE's power cost forecast. Staff must have sufficient time to review any new MONET modelling. Currently, Staff is scheduled to file rebuttal testimony on August 16, 2020, which hopefully will be sufficient time for Staff's review.

Q. What is Staff's recommendation regarding inputs related to the HBS?

A. Staff has issued several data requests asking PGE to essentially describe the error it has identified in the HBS and whether PGE has been in contact with the Northwest Power Pool regarding this issue. I believe it is reasonable to wait in carrying out any final staff review of the HBS until this issue is resolved, which PGE states should be by July's MONET update.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 391
WITNESS: KATHY ZARATE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 501

Witness Qualifications Statement

June 30, 2021

WITNESS QUALIFICATION STATEMENT

NAME:	Kathy Zarate
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Utility Economist Energy Rates, Finance and Audit Division
ADDRESS:	201 High Street SE., Suite 100 Salem, OR. 97301
EDUCATION:	Bachelor of Arts, Economics Oregon State University, Corvallis, Oregon Bachelor Degree in Law 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. 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

General Rate Cases: I have been a part of almost every energy rate case 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

Rulemaking: I have formulated energy regulation rules for utility performance incentives and cost-of-service regulation.

Low-Income: Results of my statistical sampling design and sampling procedures are incorporated into my revenue requirement testimony in Commission Docket No. UM 2058.

Auditing, Interest Rate, Affiliated Interest: I audited cost of capital and financial components (IU 437)

CASE: UE 391
WITNESS: KATHY ZARATE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 502

Exhibits in Support
Of Opening Testimony

June 30, 2021

UE 391/PGE
May 17, 2021
OPUC Data Request 56

TO: Kathy Zarate
Public Utility Commission of Oregon

FROM: Jaki Ferchland
Manager, Revenue Requirement
PORTLAND GENERAL ELECTRIC COMPANY UE 391
PGE Response to OPUC Data Request No. 56.

Request:

Please describe the factors considered, such as cost of replacement power, in adopting the timing of the 2022 maintenance for the resources.

Response:

When setting outage schedules, several factors are considered. The factors vary depending on the technology of the generator, maintenance contracts, if any, and the services provided by the generator. For all dispatchable unit outages, the PGE system need for capacity, water availability, and economics are considered. Typically, dispatchable units will not be taken offline for a planned outage if there is a high system need for the services of the unit (e.g., summer peaking season). PGE's large gas plants have Long Term Service Agreements (LTSAs) that dictate the operating interval for unit outages.
Outages are scheduled to minimize costs and include considerations for:

- PGE's system needs for energy, capacity, and operating range;
- Replacement power costs;
- Labor resource availability and cost;
- LTSAs;
- Scope of the work scheduled;
- Related transmission system work that impacts the plant;
- Forecasted operation of the unit until the next scheduled outage window; and
- FERC licensing and fish flow management.

UE 391/PGE
May 17, 2021
OPUC Data Request 57

TO: Kathy Zarate
Public Utility Commission of Oregon

FROM: Jaki Ferchland
Manager, Revenue Requirement
PORTLAND GENERAL ELECTRIC COMPANY UE 391
PGE Response to OPUC Data Request No. 57.

Request:

Please provide the following information in Excel format:

a) Projected scheduled outage rates for each unit, as reflected in final rates for each test year from 2016 through 2021.
b) Actual scheduled outage rates for each unit, for each test year from 2016 through 2021.
c) The dates, duration, and cause of scheduled outages occurring between 2016 and 2021.
d) The dates, duration, and cause of scheduled outages forecasted for 2022.
e) The minimum operation level and maximum output level of each unit.

Response:

Pursuant to the conversation with OPUC Staff on May 10, 2021, PGE provides planned maintenance outage information associated with PGE's thermal resources.

a. Attachment 057-A provides maintenance derations modeled in the final NVPC forecasts between 2016 and 2021. For additional information regarding thermal planned maintenance information please see Vol 3 - Thermal\Thermal Maintenance.
b. Attachment 057-C provides weighted equivalent scheduled outage factors for PGE's thermal plants, as reported by PGE to the North American Electric Reliability Corporation (NERC) Generating Availability Data System (GADS) from 2016 through 2021. For additional information regarding thermal planned maintenance outage information please see Vol 3 - Thermal\Thermal Maintenance.
c. Attachment 057-B provides actual planned maintenance outages for PGE's thermal plants, as reported by PGE to the North American Electric Reliability Corporation (NERC) Generating Availability Data System (GADS) from 2016 through 2021. For additional information regarding thermal planned maintenance outage information please see Vol 3 - Thermal\Thermal Maintenance.

d. See April 15 MFRs, Vol 3 - Thermal\Thermal Maintenance\Planned outages.

e. See April 15 MFR, Vol 9 - Enhancements and New Items, Model Steps 00g to 00k for Beaver, Coyote Springs, Port Westward 1, and Port Westward 2 thermal plant parameters, including minimum and maximum operating levels. For Colstrip, please see April 15 MFRs, Vol 3 - Thermal\Colstrip\Performance Parameters.

Attachments 057-A, 057-B, and 057-C are protected information subject to Protective Order No. 21-099.

CASE: UE 391
WITNESS: KATHY ZARATE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 503

Exhibits in Support
Of Opening Testimony

June 30, 2021

UE 391/PGE
OPUC Data Request 58-A

Thermal Plant Heat Rate

[redacted]

Source:
MONET Model -> PC Input Worksheet -> Thermal Plant Performance and Cost -> Heat Rate

CASE: UE 391
WITNESS: JOHN L. FOX

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 600

Opening Testimony

June 30, 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 discuss the proposed changes to PGE's NVPC forecast based on aggregation of the Blue Marmot qualifying facilities (QF) projects and the Company's proposal to change the timing of price updates for the Priest Rapids and Wanapum hydro facilities.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Exhibit Staff/602, which includes copies of PGE responses to Staff DRs.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. BLUE MARMOT QF PROJECTS AGGREGATION

Q. Please summarize the Company's position.

A. PGE's initial 2022 NVPC forecast includes costs to purchase power from five individual solar QFs (Blue Marmot I-V) owned by EDP Renewables North America (EDPR) and scheduled to come on line in 2022.[1] PGE testifies that EDPR approached PGE asking to aggregate the five individual 10 MW QF solar projects into a single 50 MW project.[2] The Company reports that key terms and conditions have been agreed to and the parties are working diligently on a final contract.[3] However, because the agreement is non-binding at this time, the anticipated change in costs associated with aggregating the projects was not included in the initial NVPC filing.

Q. Please summarize the anticipated change.

A. PGE explains it was able to negotiate a lower purchase price for the QF output, along with other favorable contract modifications.[4] The new contract price is confidential and included in PGE's testimony.[5]

Q. Why did the projects shift from prices listed in the Company's Schedule 201 to prices negotiated under Schedule 202?

A. Schedule 201 pertains to power delivered by a Qualifying Facility (QF) to the Company with nameplate capacity of 10,000 kW (10MW) or less. Schedule

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[1] PGE/100, Vhora – Outama – Batzler /50.
[2] PGE/100, Vhora – Outama – Batzler /50.
[3] See Staff/602, PGE Response to Staff Data Request 36 and UE 391_OPUC DR 036_Attach A_CONF.pdf
[4] PGE/100, Vhora – Outama – Batzler/51-52.
[5] PGE/100, Vhora – Outama – Batzler /51-52.

201 includes Commission-approved prices applicable to small QFs under 10 MW. The Blue Marmot projects are now aggregated into a single 50 MW project and their prices are negotiated under Schedule 202.

Q. Please discuss how the Company is modeling the current and estimated full year impact of the new agreement.

A. The Company anticipates a reduction in 2022 forecasted power costs of **[BEGIN CONFIDENTIAL]** [redacted][6] **[END CONFIDENTIAL]** Staff review of the Company's workpapers indicate that this is a net cost figure. In other words, 2022 project costs will decrease by **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** offset by a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[7] increase in net market purchases which appears to be due to **[BEGIN CONFIDENTIAL]** [redacted][8] **[END CONFIDENTIAL]** This is not directly comparable to the estimated 2023 full-year impact of **[BEGIN CONFIDENTIAL]** [redacted].[9] **[END CONFIDENTIAL]** Which is derived by **[BEGIN CONFIDENTIAL]** [redacted].[10] **[END CONFIDENTIAL]**

Q. Does Staff support aggregation of the projects?

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[6] PGE/100, Vhora – Outama – Batzler / 51. Staff notes that the figure in testimony is rounded down slightly.
[7] Calculated by staff comparing model output in excel files "#2022 AUT-00l.xlsm" and "UE 391_OPUC DR 037_Attach A_CONF.xlsm"
[8] PGE/100, Vhora – Outama – Batzler / 52.
[9] PGE/100, Vhora – Outama – Batzler / 51.
[10] See Staff/602, PGE Response to Staff Data Request 37 and UE 391_OPUC DR 037_Attach B_CONF.xlsx

A. Yes. The proposed change from five separate QFs to one is a very good outcome that will lower costs for ratepayers.

ISSUE 2. PRIEST RAPIDS AND WANAPUM PRICE UPDATE

Q. Please summarize the Company's position.

A. The Company proposes to include an update to the price applied to the energy generation at the Priest Rapids and Wanapum hydro facilities in the final NVPC (November 15th) modeling update.[11]

Q. How is this different from the current practice?

A. Currently, the Company includes a forecast of its NVPC for the following calendar year in a filing on April 1.[12] The initial forecast provided on April 1 is the final NVPC forecast from the previous year with updates to the specific inputs identified in the Annual Update Tariff (AUT).[13] On October 1, the Company files updated estimates with final planned maintenance outages, a final load forecast, updated projections of gas and electric prices, power, and fuel contracts.[14] Updates to the contract price for output from hydro generation facilities are currently not in the list of inputs updated in the final November 15 update. Instead, the last update for this input is on October 1.[15]

Q. What is the Company's rationale for including this change in the list of updates made in the November 15 update?

A. The Company states the contract provisions require the price to be updated based on an auction that occurs in November. Accordingly, this price change occurs after October 1 and is therefore currently not incorporated into the final

[11] PGE/200, Macfarlane-Tang/7.
[12] See PGE/204, Macfarlane – Tang / 2.
[13] *Id.*
[14] *Id.*
[15] *Id.*

NVPC.[16] The Company asserts that "by allowing for this annual update to occur in the final MONET update, what customers pay for this energy will more accurately reflect the actual price PGE will pay for energy delivered in the test year."[17]

Q. Please describe PGE's share of the projects.

A. PGE describes the relationship as follows:

> The Company has acquired a percentage of the output of the Priest Rapids and Wanapum Hydroelectric Projects under an agreement that requires PGE to pay its proportionate share of the operating and debt service costs of the projects, whether or not they are operable. The agreements further provide that, should any other purchaser of output default on payments as a result of bankruptcy or insolvency, PGE would be allocated a pro-rata share of both the output and the operating and debt service costs of the defaulting purchaser.[18]

Q. What is PGE's share of the project and when does the contract expire?

A. 8.6 percent of the project capacity or 163 megawatts.[19] The Contract will expire in 2052.

Q. Please describe Staff's review of the costs for this project.

A. Staff has reviewed the calculations supporting this input and prior inputs for 2017-2021. These calculations reflect PGE's share of project costs and output as discussed above and annual auction results as discussed in the Company's testimony.[20] The contract terms are quite complex, however the 2022 figures

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[16] *Id.*
[17] PGE/200, Macfarlane-Tang/8.
[18] Portland General Electric Company, Form 10-K for the fiscal year ended December 31, 2020, page 58.
[19] *Id* at 111.
[20] PGE/200, Macfarlane-Tang/7-8.

appear to have been calculated using the same methodology as prior years. Staff also reviewed the purchased power costs and output for the project as reported on the Company's annual FERC Form 1 filed with the Commission for years 2016-2020.[21]

Q. Does the project output assumed in NVPC vary much from year to year?

A. No. The output assumed in the filing is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** MWh. From 2017-2022 assumed output fluctuated within plus or minus **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** MWh.

Q. Does the auction revenue portion of project cost vary much from year to year?

A. Yes. Since 2017, auction revenue offsetting PGE's share of project costs has varied between **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]** The amount of auction revenue assumed in the filing is **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]** Staff notes that the auction revenue significantly reduces overall project cost included in NVPC (between **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** since 2017).

[21] See In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Annual Reports in compliance with OAR 860-027-0070 (1) and (2), Docket Nos. RE 54(5) to RE 54(9).

Q. Does Staff support the Company's proposal to update project costs in the final NVPC (November 15th) modeling update?

A. Yes. As noted above, auction revenues can vary significantly. Staff also notes that PGE's proportionate share of the operating and debt service costs underlying the contract price for 2022 will also be updated at that time. In Staff's view, the improved accuracy achieved by incorporating the most recent available information will benefit ratepayers and ought to be approved.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 391
WITNESS: JOHN FOX

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 601

Witness Qualifications Statement

June 30, 2021

WITNESS QUALIFICATIONS STATEMENT

NAME:	John L. Fox
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Financial Analyst Energy Rates, Finance and Audit Division
ADDRESS:	201 High Street SE. Suite 100 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). 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. 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. 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 391
WITNESS: JOHN FOX

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 602

Exhibits in Support
Of Opening Testimony

June 30, 2021

May 7, 2021

TO: John Fox
Public Utility Commission of Oregon

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC COMPANY
UE 391
PGE Response to OPUC Data Request No. 036
Dated April 23, 2021

Request:

Regarding Vhora – Outama – Batzler 100/51, and the statement thereon "PGE and EDPR have reached agreement on a non-binding term sheet",

a. Please provide a copy of the term sheet.

Response:

Attachment 036-A contains a copy of the non-binding term sheet. PGE notes that EDPR and PGE are in active negotiations and have not finalized an agreement. As such, terms and conditions contained in the non-binding term sheet may differ from those in the negotiated agreement, but PGE would seek to minimize those differences accordingly.

Attachment 036-A is protected information subject to protective order 21-099.

Portland General Electric Company
Non-binding Indicative Term Sheet
Subject to Mutual NDA

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

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

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

May 7, 2021

TO: John Fox
Public Utility Commission of Oregon

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC COMPANY
UE 391
PGE Response to OPUC Data Request No. 037
Dated April 23, 2021

Request:

Regarding Vhora – Outama – Batzler 100/52,

a. Please provide all work papers underlying the calculation of the forecast power cost reduction of $334,000 in 2022 and approximate savings of $1.9 million in 2023.

b. Please explain why the 2022 impact is disproportionate to the full year impact in 2023 as a percent of the current impact and current agreement, respectively.

Response:

a. Attachment 037-A provides the MONET output for the 2022 NVPC forecast with the updated price applied to the Blue Marmots contract. Attachment 037-B provides supporting calculations for the $1.9 million approximate savings expected for 2023. Attachment 037-C provides MONET output model steps that reflect the potential power cost reduction of approximately $0.3 million in 2022 and $1.9 million in 2023 associated with the Blue Marmots contract aggregation.

b. The 2022 impact is disproportionate to the full year impact in 2023 because the Blue Marmots projects are expected to come online in November 2022 compared to being operational for the full year 2023.

Attachments 037-A, 037-B, and 037-C are protected information subject to Protective Order No. 21-099.

CASE: UE 391
WITNESSES: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 700
VER ROM Integration and Schedule 125 Updates

Opening Testimony

June 30, 2020

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 (E-RFA) 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/701.

Q. What is the purpose of this testimony?

A. I am responsible for the analysis of the updates to the Variable Energy Resources (VER) Resource Optimization Model (ROM) in MONET and proposed language changes to Schedule 125, which is PGE's Annual Update Tariff (AUT) that specifies the procedures to update PGE's NVPC for the forecast year.

Q. Why does PGE propose changes to the VER ROM?

A. PGE proposes to modify the VER ROM in order to include on-system solar QFs and the solar plus battery component of the Wheatridge facility in its modeled system reserve requirement. By updating its system reserve requirement to add solar resources to its wind resources, PGE will be able to include costs to integrate solar resources in its forecasted NVPC.

Q. What changes to Schedule 125 are proposed by the Company?

A. PGE proposes five changes to the language of Schedule 125:

1. Changing the integration costs that may be included in the NVPC from "costs associated with wind integration" to "costs associated with integrating variable energy resources".[1]
2. Adding forward market prices for oil and foreign exchange rates in Schedule 125.[2]
3. Removing a one-time change to the timing of the final update to the schedule of planned maintenance outages implemented to address outages related to the 2020 Labor Day Wildfires.
4. Adding language to align Schedule 125 with customary AUT procedural schedules that allow two updates in November.
5. Including an update to the price applied to energy produced at the Priest Rapids and Wanapum hydro facilities in the list of inputs subject to change in the final update to the 2021 NVPC estimate on November 15.[3]

Q. Are there any procedural concerns that the Commission should be aware about regarding your recommended changes to Schedule 125 and PGE's VER ROM integration model?

A. Yes. Before giving my recommendation, it is worth noting that any language changes to PGE's Schedule 125 are reserved for proceedings other than AUTs, such as a general rate case.[4] I conduct my analysis and make my

[1] PGE/204, Macfarlane – Tang/1.
[2] *Id.*
[3] *Id.*
[4] Order No. 07-015, p. 19.

recommendations assuming PGE will file a general rate case in 2021. If PGE fails to file a general rate case in 2021, any proposed changes to Schedule 125 must be rejected outright.

Q. What is your recommendation?

A. I see no problem with including solar resources in PGE's reserve requirements in MONET and including costs to integrate solar in Schedule 125 assuming that PGE files a general rate case in 2021. I am satisfied that the associated costs of PGE's changes to the VER ROM integration model are appropriately included in forecasted NVPC and recommend only minor changes be made to the proposed language in Schedule 125 in the 2022 AUT filing. In short, my only recommended language change to Schedule 125 is to replace "Wind Resources" in PGE's proposed Schedule 125 with "Wind and Solar resources" instead of PGE's proposed "Variable Energy Resources." My recommended language change is meant to be inclusive of any wind plus battery or solar plus battery resources.

Q. Please explain the purpose of the ROM.

A. PGE explains that the ROM is a production cost model that simulates the dispatch of PGE resources to meet PGE loads and to interact with wholesale energy markets.[5] "The ROM incorporates a granular treatment of PGE resource performance, and captures phenomena related to renewable integration and resource flexibility through multi-stage optimal unit commitment and dispatch with imperfect forecast information, sub-hourly

[5] PGE/100, Vhora – Outama – Batzler/35.

timesteps, and operating reserves."[6] PGE also uses the ROM to estimate VER integration costs in the IRP process.[7] PGE states that updating the system reserves obligations such as regulation and load following for the "year in purpose" is part of the ROM set up process.[8]

Q. How do net power costs change after adding solar generation to the ROM modeling of reserve requirements?

A. Including solar resources in the ROM model adds approximately $836,000 to the total net power cost.[9]

Q. Has the Company attempted to incorporate costs associated with integrating solar resources into the forecast of NVPC in past AUT proceedings?

A. Yes. PGE proposed to change "costs associated with wind integration" to "costs associated with variable energy resources integration" in Schedule 125 in the 2021 AUT proceedings.

Q. How was PGE's proposed change resolved in the 2021 AUT?

A. Staff and parties agreed to leave Schedule 125 unchanged. The Joint Testimony in Support of Settlement reflects that parties had different reasons for reaching this settlement. CUB wanted changes to the language to only reflect the resources in the Company's VER portfolio.[10] Staff did not have adequate time to analyze the Company's proposed model update and

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[6] PGE/100, Vhora – Outama – Batzler/35.
[7] *Id.*
[8] *Id.*
[9] PGE/100, Vhora – Outama – Batzler/37.
[10] UE 377 – Stipulating Parties/100, Soldavini – Gehrke – Kaufman – Batzler/6.

changes to Schedule 125 because the changes were proposed late in the 2021 AUT proceedings.[11]

In response to the above concerns, the Company agreed to withdraw its proposed changes to the VER ROM model and Schedule 125 in the 2021 AUT.

Q. How did you do to analyze the updates to the VER ROM model?

A. I analyzed whether including costs to integrate solar resources in the 2022 AUT is consistent with the Commission's other actions regarding PGE's solar resources and whether PGE's proposed changes accurately reflect the cost of VER ROM integration and the associated change in required reserves.

Q. Is including solar resources in the 2022 AUT filing consistent with the Commission's treatment of PGE's solar resources in other proceedings?

A. Yes. As PGE pointed out in its opening testimony, PGE added solar resources into its Wind Integration Study in its 2016 IRP and renamed it the Variable Energy Resource Integration Study. PGE included its VER Resource Integration Study in its 2019 IRP. The Commission issued orders of acknowledgment for both IRPs.[12]

[11] *Id.*
[12] Order No. 20-152; Order No. 17-386.

Q. Why would integrating a renewable energy source such as solar add to PGE's overall power costs?

A. It is important to remember that VER stands for *Variable* Energy Resource, meaning that oftentimes these new resources aren't running. That means that as PGE adds more VER, it must also hold additional reserves to supplement its VER when the VER is not running. PGE's VER ROM calculates the added required reserves needed to integrate the proposed VER.

Q. What did you do to analyze whether the costs associated with VER integration as presented by PGE are accurate?

A. I began my investigation by reviewing the method by which PGE calculates its reserve requirements as presented in PGE's workpapers. I then inspected all other relevant workpapers to ensure that all values accurately reflect the costs associated with integrating new solar VER.

Q. Do you believe that PGE accurately reflects the costs of integrating solar resources?

A. Yes. I am convinced that PGE has portrayed the added costs of reserve requirements for its VER ROM integration the 2022 AUT to the best of MONET's abilities.

Q. Do you have any recommended adjustments to PGE's power costs in the 2022 AUT with regards to VER ROM integration and the associated change to reserve requirements?

A. No, I do not.

Q. How did you scrutinize the language change to Schedule 125?

A. I considered four questions when analyzing the proposed language change to Schedule 125:

1. Does the proposed language allow the Company to recoup its costs associated with the relevant projects?
2. Does the proposed language allow the Company to pursue its energy-planning goals?
3. Does the proposed language properly protect ratepayers?
4. If the answer to any of the first three questions is "no", what alternate Schedule 125 language exists that can allow the Company to properly recoup costs and pursue its energy-planning goals while still protecting ratepayers?

Q. With regards to your first question regarding cost recovery, does PGE currently have any non-wind or non-solar variable energy resources?

A. PGE's testimony on the non-price changes to Schedule 125 lists only wind and solar resources by name when discussing the possible variable energy resources.[13] I issued a data request to clarify whether there were indeed other resources that should be included apart from wind and solar. In its response to Staff DR 39, PGE notes that it "considers only wind and solar resources as VER."[14]

[13] PGE/100, Vhora – Outama – Batzler/35-36.
[14] Staff/702, Dlouhy/1, PGE Response to Staff DR 39.

Q. Given this, are there other ways to change Schedule 125 to ensure the Company can properly include all its current VER assets?

A. Yes. The Company can instead replace all instances of "costs associated with wind integration" in the current Schedule 125 language with "costs associated with wind and solar integration." This would not exclude any VER currently held by PGE from Schedule 125.

Q. With regards to your second question, does the Company's proposed change allow it to pursue its energy-planning goals?

A. The Company's general reference to "variable energy resources" would allow the Company to include the costs of integrating any variable energy resource, in its NVPC forecast in the AUT. This broad language therefore would facilitate PGE's recovery of integrating different types of renewable resources without the need for a general rate case or other proceeding to change the language of Schedule 125.

PGE notes that this is the reason behind its choice of language in its response to Staff DR 39, saying:

> Changing the Schedule 125 language to allow updates associated with VER integration would ensure the cost to integrate new types of variable resources is captured in the NVPC forecast without needing a future update to the Schedule 125 language.[15]

[15] Staff/702, Dlouhy/1. PGE Response to Staff DR 39.

Q. Has the Company identified any non-wind or non-solar VER that would require this degree of flexibility now?

A. No. As evidenced by the Company's response to Staff DR 39, the Company only uses wind and solar VER.[16]

Q. With regards to your third question, please discuss any possible ratepayer exposure from the Company's proposed language changes to Schedule 125?

A. The largest ratepayer exposure in the Company's proposed language change comes from its ambiguity. As the Company states, the use of "variable energy resources" instead of "wind and solar resources" allows the Company to integrate any type of VER. PGE's proposed language could allow it to put a new, untested VER into rates without the benefit of an integration study supporting the costs.

Q. With regards to your fourth question, is there a way to change the proposed language allow PGE to recoup its costs, achieve its energy-planning goals and protect ratepayers?

A. Yes. By changing the language from "wind resources" to "wind and solar resources", ratepayers are less exposed to the ambiguity described above but PGE will be able to recoup its costs related to integration of the VER currently on its system and achieve its energy-planning goals.

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[16] *Id.*

Q. Is it your intention to exclude the battery portion of a solar plus battery or wind plus battery with your proposed language, such as the solar plus battery component of the Wheatridge facility?

A. No. As I read it, any battery that is directly paired to a wind or solar resource should be counted as part of the wind or solar resource, particularly since the presence of a battery will be pertinent to the required reserves that the VER ROM attempts to forecast. This means that the integration of the solar plus battery component of the Wheatridge facility would be included. I was unable to find any past precedent to indicate otherwise but would be amenable to modifications to my language should it arise.

Q. Did you analyze any other changes to the language of Schedule 125?

A. Yes. There were four other changes to Schedule 125 that I analyzed:

1. Adding forward market prices for oil and foreign exchange rates in Schedule 125.[17]
2. Allowing PGE to update its schedule of planned maintenance outages on November 6, closer to the November 15 date on which the final forecast of NVPC is made.[18]
3. Adding language to align Schedule 125 with customary AUT procedural schedules that allow two updates in November and removing a one-time November update related to planned outages

[17] PGE/204, Macfarlane – Tang/1.
[18] PGE/204, Macfarlane – Tang/2.

implemented to address outages related to the 2020 Labor Day Wildfires.

4. Including an update to the price applied to energy produced at the Priest Rapids and Wanapum hydro facilities in the list of inputs subject to change in the final update to the 2021 NVPC estimate on November 15.[19]

Q. Do you support including oil and foreign exchange rates forward market prices in Schedule 125?

A. Yes. As detailed in PGE's opening testimony, this change is in alignment with the Commission order that establishes the scope of the AUT.[20] I have no issue with allowing the company to include oil and foreign exchange rates in its forward curves insofar as they are useful in properly forecasting power costs.

Q. Do you support removing the November 6 update to scheduled planned outages?

A. Yes. As detailed in PGE's response to Staff DR 40, the change that PGE proposes making removes language that was put into place in response to the extraordinary wildfire events of September 2020.[21]

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[19] *Id.*
[20] PGE/200, Macfarlane – Tang/7.
[21] Staff/702, Dlouhy/2, PGE Response to Staff DR 40.

Q. Do you support PGE's proposed language regarding a November 6 update and estimate of NVPC?

A. As noted by PGE, the proposed change is an update to align Schedule 125 with customary AUT procedural schedules that allow two updates in November.[22]

Q. Do you support the changes to add Priest Rapids and Wanapum hydro facilities to PGE's November 15 filing requirements?

A. Yes. As detailed in Staff/600, Staff supports allowing PGE to change the price for the output of the hydro facilities in accordance with a contract change anticipated in early November.[23]

Q. What is your overall recommendation on PGE's VER ROM integration and non-price changes to Schedule 125?

A. I recommend no monetary adjustment to the 2022 AUT and recommend that PGE replace "wind integration" in Schedule 125 with "wind and solar integration" instead of "variable resource integration" as was proposed by the Company.

Q. Does this conclude your testimony?

A. Yes.

[22] Staff/702, Dlouhy/2, PGE Response to Staff DR 40.
[23] PGE/204, Macfarlane – Tang/7.

CASE: UE 391
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 701

Witness Qualification

June 30, 2021

WITNESS QUALIFICATION STATEMENT

NAME:	Curtis Dlouhy
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Economist Energy Rates, Finance, and Audit Division
ADDRESS:	201 High St. SE Ste. 100 Salem, OR 97301-3612
EDUCATION:	PhD, Economics University of Oregon, Eugene, OR Master of Science, Economics University of Oregon, Eugene, OR Bachelor of Arts, Economics & Math Nebraska Wesleyan University, Lincoln, NE
EXPERIENCE:	I have been employed by the Oregon Public Utility Commission (OPUC) 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, UE 390(ongoing), and UE 391(ongoing). Prior to working for the Commission, I was employed by the University of Oregon as a graduate employee where I taught classes in Intermediate Microeconomics, Industrial Organization and Antitrust Economics. My PhD dissertation 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 391
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 702

PGE Responses to Staff Data Requests.

June 30, 2021

May 10, 2021

TO: Curtis Dlouhy
Public Utility Commission of Oregon

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC COMPANY
UE 391
PGE Response to OPUC Data Request No. 039
Dated April 26, 2021

Request:

Please discuss why replacing the word "wind" with "variable energy resources" is necessary rather than simply adding in language to include solar integration.

Response:

As technology evolves, other types of resources could be developed that might be considered variable energy resources (VERs). Changing the Schedule 125 language to allow updates associated with VER integration would ensure the cost to integrate new types of variable resources is captured in the NVPC forecast without needing a future update to the Schedule 125 language. However, for this proceeding and within PGE's Integrated Resource Planning process, PGE currently considers only wind and solar resources as VERs.

May 10, 2021

TO: Curtis Dlouhy
Public Utility Commission of Oregon

FROM: Jaki Ferchland
Manager, Revenue Requirement

PORTLAND GENERAL ELECTRIC COMPANY
UE 391
PGE Response to OPUC Data Request No. 040
Dated April 26, 2021

Request:

Please refer to PGE/204, Macfarlane – Tang/2. Discuss why PGE is proposing to make permanent the November 6 deadline to file updated planned maintenance outages timeline that was originally enacted as a temporary measure in response to the extraordinary wildfire events of 2020.

Response:

PGE is not proposing to make permanent the addition to Schedule 125 that allowed a one-time only update of final maintenance outages for certain hydro facilities as a result of extraordinary wildfire events in 2020 within the November 6 MONET update in PGE's 2021 AUT. In fact, as reflected in PGE Exhibit 204, page 2, PGE is removing that addition.

PGE instead is proposing an update to align Schedule 125 with customary AUT procedural schedules that allow two updates in November. Exhibit 204 provides the items to be updated during the first November update (on or before November 6), neither of which being updates to planned maintenance outages. Per the Schedule 125 language, PGE will file estimates with final planned maintenance outages "on or before October 1st of each calendar year".

CASE: UE 391
WITNESS: MAX ST. BROWN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 800

Opening Testimony

June 30, 2021

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

A. My name is Dr. Max St. Brown. I am a Senior Utility Analyst employed in the Utility Strategy & Integration Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/801.

Q. What is the purpose of your testimony?

A. I describe Staff's review of PGE's load forecast and PGE's Rate Spread/Rate Design.

Q. How is your testimony organized?

A. My testimony is organized as follows:

My Table of Figures is as follows:

ISSUE 1. LOAD FORECAST

Q. What is PGE's load forecast for 2022 retail load?

A. PGE's initial 2022 retail load forecast is 19,437 GWh, which is approximately a 0.4 percent increase from the final test year 2021 forecast in last year's AUT.[1]

Q. What are the primary drivers of the increase in load in the 2022 AUT?

A. PGE describes that the forecasted increase in total load is "driven by offsetting impacts in residential and commercial energy deliveries as usage moves from the home to the workplace following the COVID-19 pandemic and continued growth in energy deliveries to the industrial customer class."[2]

Q. How did Staff analyze this issue?

A. Staff reviewed the Company's workpapers related to load forecast to ensure proper calculation of the model. Staff focused on the load forecasts that exhibited the largest changes. As described in Staff's 2021 AUT testimony in Docket No. UE 377, "Staff traditionally does not produce a full model replication of the Company's load forecast in every power cost filing, but reviews the Company's forecast to determine whether it is reasonable on a short-term basis (for the AUT test year)… one of Staff's main objectives is to verify that the methodology used in the AUT filing is the same as that used in a GRC where a more extensive review of the Company's forecast is performed."[3]

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[1] PGE/100, Vhora – Outama – Batzler/10.
[2] PGE/100, Vhora – Outama – Batzler/54.
[3] UE 377 Staff/300, Gibbens/9-10.

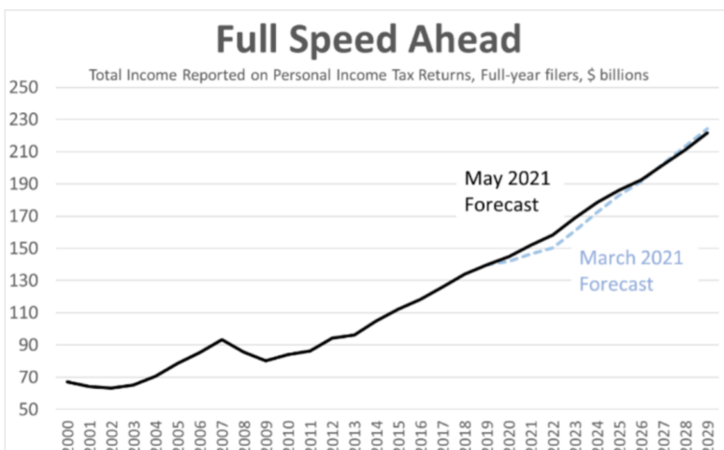
Q. Did PGE use the same load forecasting methodology as in a GRC?

A. Yes, UE 391 uses the same forecast models used in UE 377, which are from PGE's most recent GRC (Docket No. UE 335).[4]

Q. Has PGE incorporated the impacts of COVID-19 in its forecast?

A. Yes, PGE included more recent actual load data and the most recent available economic forecasts from the Oregon Office of Economic Analysis (OEA) as inputs into its load forecast.[5] The OEA forecasts relate to economic recovery. The figure below is reproduced from OEA's Economic Forecast and shows the upwards trajectory of total Oregon income. This particular forecast was not used by PGE, but is illustrative of the effects of COVID-19 that were included by PGE:[6]

Figure 1: Total Oregon Income from OEA's May 2021 Economic Forecast



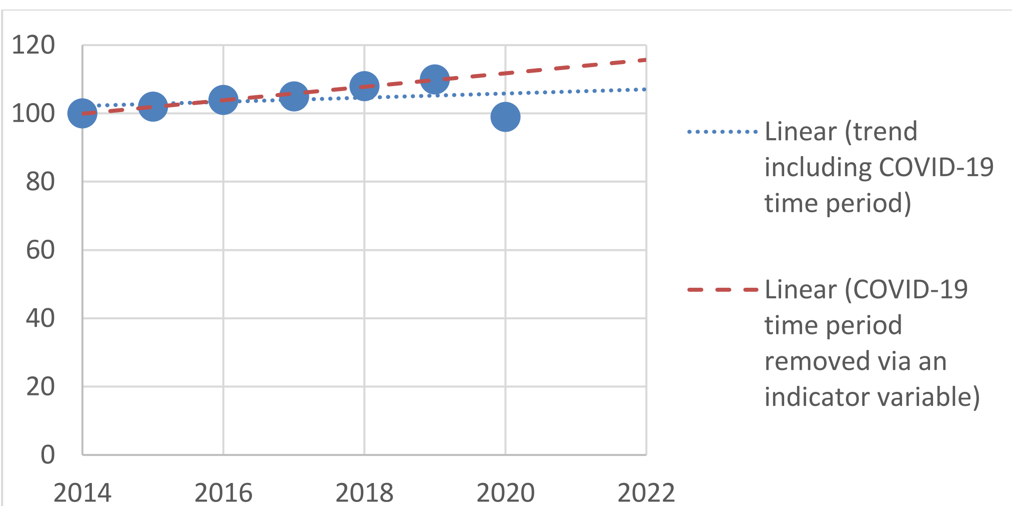
[4] PGE/100, Vhora – Outama – Batzler/55.
[5] Ibid.
[6] Figure reproduced from page 23 of the Oregon Office of Economic Analysis' May 2021 Economic forecast.

The purpose of the figure above is to show the general trend of economic recovery (note that PGE does not use the OEA income variable in its load forecasts but does use the OEA unemployment rate, which is also recovering).

Q. How did PGE incorporate the impacts of COVID-19 in its load forecasts?

A. PGE's workpapers show that it added a COVID-19 indictor variable to many of its forecasts. The indicator variables generally have the expected impacts including increased use-per-customer for residential customers during the COVID-19 time period and reduced commercial loads during that time period. Including indicator variables allows the load forecasts to have a more accurate long-term trend coefficient. For instance, consider this simplified example of hypothetical commercial load data:

Figure 2: Hypothetical Commercial Load



In the figure above, the hypothetical commercial load data is set at 100 in the year 2014, grows modestly in each year until 2020, and then falls sharply in 2020 due to the impacts of COVID-19. A best fit line using all seven years of data will be averaged down by the year 2020. But, as PGE has done via an indicator variable, if the time periods impacted by COVID-19 are not included in the trend, the best fit line matches the prior trend.

Q. In general, does Staff find PGE's use of COVID-19 indicator variables in its load forecast appropriate?

A. Yes, and this matches a typical approach used by many utilities to model known shifts in load for a time period. Furthermore, in PGE's 2019 IRP LC 73, Staff raised concerns about PGE's use of out-of-model adjustments for COVID-19. Staff recommended that PGE not use out-of-model adjustments.[7] Staff appreciates that PGE is not using out-of-model adjustments here.

Q. Does Staff propose an adjustment to load forecasting?

A. No, not at this time. Staff has reviewed the Company's inputs and methodology and finds no errors. Given the unknown and potentially significant impacts of COVID-19 on load demand, Staff will continue to review as the Company updates its load forecast inputs to include any updated forecast that incorporates the impacts of the pandemic.

[7] In the Matter of PGE 2019 Integrated Resource Plan LC 73, Order No. 21-129 May 3, 2021 at Appendix A page 5.

ISSUE 2. RATE SPREAD/RATE DESIGN

Q. How does PGE spread its Schedule 125 AUT Rates?

A. PGE spreads Schedule 125, the AUT rates, based on the generation allocation. For example, residential (Schedule 7) customers have 45.10 percent of the forecasted base generation revenues in 2022 and are also assigned 45.10 percent of the AUT rates. Likewise small commercial (Schedule 32) customers are assigned 8.54 percent of the AUT rates to match their 2022 forecasted base generation revenues share.

Q. Does Staff have any concern with PGE's Schedule 125 rate spread?

A. No, PGE's rate spread is consistent with the design of Schedule 125.

Q. Did Staff identify any concerns with PGE's proposed rate design?

A. Staff noted that for some direct access rate schedules, the "System Usage Charge" went from a rebate to a charge for some direct access rate schedules. Staff contacted PGE to determine the reason for this change.

Q. Have Staff's concerns related to rate design been resolved?

A. Yes, Staff met with PGE's testimony witness Teresa Tang on May 13, 2021, to discuss the change to the System Usage Charge for some direct access schedules. PGE's witness Ms. Tang clarified that the change from a rebate to a charge is due to different vintages of direct access customers. Customers that have been opted out for more than five years (since 2017) do not have to pay the Schedule 129/139 opt out rate anymore. Since there is less opt out revenue collected, less is distributed so the rebate went to a charge.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 391
WITNESS: MAX ST. BROWN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 801

Witness Qualifications Statement

June 30, 2021

WITNESS QUALIFICATIONS STATEMENT

NAME:	Max St. Brown
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Analyst Utility Strategy and Integration Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	Ph.D., Economics (2013) Washington State University B.S., Economics (2009) Central Washington University
EXPERIENCE:	I have been employed by the Public Utility Commission from July 2015 to December 2018 and since April 2020, with my current position being a Senior Utility Analyst, in the Utility Program's Utility Strategy and Integration Division. Prior to rejoining the OPUC, I worked as a Senior Economist in the Research Section at the Oregon Department of Revenue. From 2013 to 2015 I served as an Assistant Professor of Economics at Eckerd College, teaching courses including: Econometrics, Labor Economics, and Intermediate Microeconomics. My published research in peer-reviewed academic journals includes a study of the U.S. renewable energy industry and includes international economic impact studies. I have been a witness in Oregon PUC general rate cases: UE 374, UG 390, UG 389, UE 319, UG 287, UG 288, UG 305, UG 325.

CASE: UE 391
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 900

Redacted
Opening Testimony

June 30, 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 AUT filing and Staff's review of and recommended Commission action regarding the Wheatridge Performance Report and forecasts, and capacity planning in the AUT.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. WHEATRIDGE PERFORMANCE REPORT AND FORECASTS

Q. Please describe the Wheatridge Renewable Energy Facility.

A. Wheatridge is a 300 MW wind, 50 MW solar, and 30 MW four-hour duration energy storage facility located in Morrow County, Oregon. The wind facility came online in the 4th quarter of 2020, while the solar and battery storage portions are scheduled to come online at the end of 2021. PGE has forecasted the NVPC benefits of all aspects of Wheatridge into this year's AUT. This includes 100 MW of wind, which PGE will own, and a 200 MW long-term PPA for wind, and the solar plus storage component owned by NextEra.

Q. How does PGE propose to model Wheatridge in this year's AUT?

A. PGE proposes to use the standard forecast methodology for its wind generating facilities in the AUT. This is a five-year moving average forecast that utilizes the P50 forecast included in the RFP scoring process for any year where actual historical data is unavailable. Being that the facility has very little historical data to date, the vast majority of the forecast is based on the P50 forecast.

For solar, the capacity factor and generation profile are based on generation data provided by the bidder in PGE's Renewable RFP, similar to the P50 forecast used for wind. The battery is modeled based on the terms of the PPA; the battery charges during sunlight hours, per the generation profile to maximum, and then is discharged fully during the evening ramp.

Q. Does Staff agree with this methodology?

A. Yes. Staff believes that the circumstances surrounding the investment decision may warrant a modified methodology for capacity factor calculation, however two circumstances mitigate the necessity to propose any alternative approach at this time. The first is that Staff's preferred approach and PGE's proposed approach would result in almost no difference for this year's AUT as they would both rely fully on the P50 forecast for the methodology. The second is that the Commission required PGE to file a performance report in Order No. 20-321. This report is meant to allow parties and the Commission to examine the relative performance of Wheatridge compared to the forecasted benefits used to make the investment decision.

Staff discusses its review of the performance report below and will continue to review the performance report and will propose any warranted to Wheatridge modeling adjustments should they become necessary. Given these two factors, Staff recommends no change to the Company's proposed methodology for Wheatridge capacity factor calculation at this time.

Q. What is the Wheatridge facility performance report?

A. In Docket No. UE 370, the Commission directed PGE to file an annual report as part of its AUT. In Order No. 20-321, the Commission stated:

> In order to assist us and the parties in an appropriate ongoing review of the Wheatridge facility, we direct PGE to file a report with its annual power cost filings, detailing the performance of the Wheatridge facility, compared to the estimated performance that was used to justify the acquisition of the project. This report should

> include information that allows transparency into whether the expected benefits and costs to customers over time are similar to those originally projected and should include an evaluation of expected and realized PTCs, project output and capacity, and revenue requirement, including ongoing operating and maintenance costs. The report will help us assess what factors may cause a deviation from forecast costs and benefits and will assist us in determining whether any adjustments based on the just and reasonable standard are warranted. We direct PGE to work with Staff and the parties to this proceeding on the format and particulars of the report, and any challenges in providing the information specified.[1]

Following a discussion with parties, PGE agreed to include the report, which includes cumulative and annual information regarding forecast and actual expense and costs, forecast NVPC in prices, historical generation and capacity factor, and production tax credits generated and utilized.

Q. Has Staff reviewed the Company's report?

A. Yes. Staff has reviewed the Company's initial report and finds it complies with the Commission's direction and agreement amongst the parties.

Q. Does Staff have any recommended changes or additions to the report?

A. Yes. Staff believes that it would be helpful to parties if PGE made two additions to the Wheatridge performance report. The first is that PGE include the initial

[1] Order No. 20-321, at 11.

forecast of Wheatridge benefits for PTC and NVPC that is filed contemporaneously with the report. Although the PTC benefits are relatively easy to identify in the Company's workpapers, the NVPC impact of Wheatridge is not. Staff notes that the Company could include a footnote that identifies that these numbers are subject to change through the course of the proceeding but believes that the information could provide additional information to stakeholders that read the report.

Staff also believes that the Company could include in the performance report a short narrative description for any large deviations between forecasts and actuals in the preceding calendar year. One potential example would be a description of the impact an extended forced outage had on the actual generation or capacity factor in a given year.

Staff notes that the Company already does provide some pertinent footnotes to the report when further clarification is warranted and cannot say if the Company may already be planning to provide Staff's requested narrative explanations. In any event, Staff makes the request to ensure the report is as useful as possible.

ISSUE 2. CAPACITY PLANNING

Q. Why is Staff addressing this issue in the context of an annual power cost filing?

A. PGE describes an apparent on-going and increasingly important issue regarding changes to the energy resource capacity landscape within the Western Electricity Coordinating Council (WECC) region in its opening testimony.[2] The Company notes that the regional resource mix is shifting from dispatchable baseload generation to non-dispatchable renewable generation.[3] In the Company's view, this change adds complexity to forecasting, planning, procuring, and dispatching resources. While this has implications in the long-term IRP process, it also has potential implications in shorter-horizon dockets like the AUT.[4]

Q. Please elaborate and explain the impacts of the shift in resource mix.

A. PGE noted that capacity concerns and the shift to non-dispatchable resources has caused volatility in the market. PGE argues that this has caused a divergence between actual operations and the MONET model.[5] In recent years, MONET dispatches plants traditionally used for meeting peak capacity needs into the market as they become more economical to run during more hours during the year based on the forward market curves.[6] This is a practice that can't be duplicated by PGE's Power Operations (Power Ops) as they

[2] PGE/100, Vhora – Outama – Batzler / 11-14.
[3] *Id.*
[4] *Id.*
[5] *Id.*, p. 14.
[6] *Id.*, p

reserve those two units during extreme events in order to ensure customers are not subject to extreme market prices.[7] This leads to an overestimation of the benefits achievable through market sales, particularly by Port Westward 2 (PW2) and Beaver, PGE's peaking plants, in the AUT.[8]

Q. Does Staff agree with PGE's analysis of the issue?

A. Yes. Staff believes that PGE has raised a potential concern that may warrant an adjustment to methodology. However, a much more in-depth analysis should be completed prior to implementing any methodological changes. Staff continues to analyze the issue and looks forward to working with the parties and stakeholders to ensure the AUT modeling results in fair, just, and reasonable rates. In the meantime, the following is a brief discussion of the issue.

Q. Please describe how Staff reviewed the issue?

A. In an initial test of the veracity of PGE's claims, Staff reviewed the forecast and actual dispatch of the two capacity plants that PGE notes are particularly impacted by the market changes. PGE claims that MONET is now identifying economic market sales that Power Ops is unable to take advantage of. Confidential Figure 1 below shows the AUT forecast compared to actuals by year for PW2 and Beaver.

[BEGIN CONFIDENTIAL]

[7] *Id.*, p. 17.
[8] *Id.*, pp. 17-18.

Figure 1

[redacted]

[END CONFIDENTIAL]

It is clear from the graph that MONET is dispatching PW2 and Beaver more in recent years. While PGE's actual dispatch of Beaver has stayed relatively flat, it appears the Company is also increasing its actual dispatch of PW2. So, while the potential issue may be becoming more significant for Beaver data, it appears the magnitude of any forecast discrepancy remains relatively the same for PW2 from 2016-2020. Staff notes that PGE retired Boardman in October of 2020, thus the actual operational data provides relatively little clarity on how these two plants' dispatch may change in response to fewer options in the resource stack.

Q. Did Staff perform any other analysis of the issue?

A. Yes. Staff performed additional analysis to identify the magnitude of the potential issue. To do this, Staff reviewed the hourly dispatch for Beaver and PW2 during the summer months (July 15-September 15). Staff assumed that

Beaver and PW2 were the highest cost resources in the resource stack, and thus anytime the model showed a market sale in a given hour where the two resources were also dispatching, the generation was assumed to be sold into the market for economic sales. Staff then calculated the relative savings from the plants whenever it could be inferred that any generation from the two capacity plants went to serving PGE load. The assumption being that anytime the two highest cost resources were dispatched to serve load, the economic dispatch was avoiding a higher cost market purchase.

It was important to Staff to differentiate between the purposes of the capacity plant dispatch because these plants are designed to serve customer load when necessary. If they were being dispatched to serve load, this would not comport with the issue raised by PGE. MONET modeled dispatch to serve load, would presumably be capacity utilized by Power Ops in actual operations to meet customer load.

Staff identified where MONET made dispatches to serve load by examining two circumstances. The first, where market purchases occurred in a given hour and the two plants dispatched (the model does not simultaneously make purchases and sales). The second, where generation exceeded market sales. In the second circumstance, the portion of generation that was in excess of market sales was assumed to be serving load and subtracted from the portion of generation that was sold to the market.

Once Staff identified the purpose of the dispatch, Staff multiplied the generation used for sales by the Mid-C market price for that hour. Staff then multiplied the hourly generation of PW2 and Beaver used to serve load by the Mid-C market price for that given hour and subtracted from the sales revenue.

Q. What were the results of this analysis?

A. Staff found that in **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of the summer hours, some generation from PW2 and Beaver was dispatched into the market in the MONET model. On average **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of the maximum generation from the plants was included in these sales. This equates to roughly **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of capacity used for market sales during the entire summer. In **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of all hours, the generation was used to serve PGE load.

In terms of dollar impact, Staff estimated that the dispatch of Beaver and PW2 for economic sales to the market reduced NVPC by approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Staff cautions that this is a rough estimate that likely provides the maximum impact the issues has on NVPC. Staff did not account for the marginal cost of running these plants. Staff also notes that Power Ops is able to release excess capacity to the market for economic sales on “normal weather days”, which are usually known in the week or day-ahead planning.[9] Meaning that some of the transactions identified by Staff may in fact be reflections of actual benefits realized by PGE instead of a modeling issue.

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[9] PGE/100, Vhora – Outama – Batzler/18. Lines 3 – 6.

Q. Does PGE offer any proposals to mitigate this concern?

A. No. PGE made no firm proposals in its opening round of testimony, however the Company does offer some potential solutions. These are:

- Enter into a capacity contract to address the summer capacity concern;
- Withhold a portion of Beaver and PW2 capacity from the MONET dispatch stack during the summer; and
- Change MONET to introduce a capacity planning capability to the model.

Q. What is Staff's view of the proposed solutions to the potential modeling issue?

A. Staff has not concluded if the solutions are acceptable. Staff reiterates that it continues to analyze the apparent issue and is not in a position to make a firm recommendation on a potential solution at this time, but instead offers comments in order to further the discussion and considerations on the issue.

Q. What is Staff's view of the proposed capacity contract?

A. Staff does not believe PGE meant to imply that the Company would enter into a capacity contract solely for the purpose of solving a modeling issue in the AUT. However, if the Company evaluates the costs, benefits, and risks to customers and identifies that entering into a capacity contract for summer reliability best meets customers' needs, Staff would support the contract should Staff deem it prudent. If the contract decision was made to meet customers' reliability needs and it also served to reduce or eliminate the modeling concerns, Staff views this as the simplest and most straight-forward approach.

Q. What is Staff's view of the proposed plant outage during summer?

A. PGE's proposal to artificially withhold a portion of Beaver and PW2 capacity from July 15 to September 15 is a potential solution assuming PGE takes necessary precautions to ensure the modeling adjustment does not over-estimate the problem. As Staff noted previously, its initial estimate is that roughly **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of Beaver and PW2 capacity is being utilized to sell into the market during this timeframe. Further not all of the transactions included in those sales would be an over-estimation of what PGE could do in actual operations. Thus, on its surface, this solution seems to over-estimate the potential problem, and could lead to an under-estimation of the benefit these two plants provide to customers. However, if PGE could come up with a principled approach, backed by data, to identify a proper amount of capacity to withhold, which would ideally only isolate the transactions where the model was unrealistically selling into the market, Staff may support this solution.

Q. What is Staff's view of the proposed capacity planning capability in MONET?

A. PGE notes that this is a longer-term solution that would require a more complex change to MONET's algorithm. Staff has questions related to the methodology but would support the modeling change as long as it made reasonable assumptions and resulted in a more accurate forecast of NVPC.

Q. Does Staff have any further comments on this issue?

A. Staff notes that it looks forward to further discussions with parties and intends to dig further into this concern. Staff does not intend to imply that it has come to any firm conclusions on the issue, but instead hopes that this discussion will provide parties and the Commission with a sense for the concerns and potential scope of the matter. Staff encouraged PGE to review and refine Staff's analysis and work with stakeholders to identify the best possible outcome in this docket and future AUT filings.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 391
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 901

Witness Qualifications Statement

June 30, 2021

WITNESS QUALIFICATION STATEMENT

NAME: Scott Gibbens

EMPLOYER: Public Utility Commission of Oregon

TITLE: Policy and Economic Analysis Manager
Strategy and Integration Division

ADDRESS: 201 High St. SE Ste. 100
Salem, OR 97301-3612

EDUCATION: Bachelor of Science, Economics, University of Oregon
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 Policy and Economic Analysis manager since February 2021, and prior to that I was the power cost team manager from 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, UE 375, UE 379 and current UE 390. PGE UE 308, UE 310, UE 319, UE 329, UE 335, UE 346, UE 359, UE 362, UE 377 and current UE 391. 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 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.