Oregon
Tina Kotek, Governor

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

June 23, 2025

Via Electronic Filing

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

RE: Docket No. UE 452 – In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, 2026 Annual Power Cost Update Tariff.

Attached for Opening Testimony filing are the following exhibits:
Exh 100-101 Kim REDACTED
Exh 200-202 Abraham
Exh 300-303 Dyck REDACTED
Exh 400-406 Gariety
Exh 500-502 Zhao REDACTED
Exh 600-603 Lockwood REDACTED
Exh 700-702 Mondragon REDACTED
Exh 800-803 Bolton REDACTED

Confidential exhibits and Excel exhibits included with this filing are:

Confidential exhibits:
Exh 100-101 Kim CONF
Exh 300-303 Dyck CONF
Exh 303 Dyck UE 452_CONF_PGEtoOPUC_DR12R_Attach12-A_04232025.xlsx
Exh 500-502 Zhao CONF
Exh 600-603 Lockwood CONF
Exh 700-702 Mondragon CONF
Exh 800-803 Bolton CONF
Exh 803 Lockwood 1_2026 AUT Apr Filing Reliability Contingency Event Forecast CONF.xlsx

/s/ Emily Dolph
Emily Dolph
Oregon Public Utility Commission
(503) 510-7925
emily.dolph@puc.oregon.gov

<u>CERTIFICATE OF SERVICE</u>

UE 452

I certify that this day I served the foregoing document upon all the following parties or attorneys 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 (which may include a link to a secure shared file service).

Dated this 23rd day of June 2025 at Salem, Oregon.

/s/ *Emily Dolph*

Emily Dolph
Public Utility Commission
201 High Street SE, Suite 100
Salem, Oregon 97301-3398
Telephone: (503) 510-7925

ALLIANCE OF WESTERN ENERGY CONSUMERS	
JULITTA BRANNON **(C)** DAVISON VAN CLEVE, P.C.	107 SE WASHINGTON STREET, SUITE 430 PORTLAND OR 97214 jlb@dvclaw.com
MICHELLE MADSEN **(C)** DAVISON VAN CLEVE, P.C.	107 SE WASHINGTON ST STE 430 PORTLAND OR 97214 mnm@dvclaw.com
TYLER C PEPPLE **(C)** DAVISON VAN CLEVE	107 SE WASHINGTON ST STE 430 PORTLAND OR 97214 tcp@dvclaw.com
OREGON CITIZENS UTILITY BOARD	
RYAN TRAN **(C)** OREGON CITIZENS' UTILITY BOARD	610 SW BROADWAY STE 400 PORTLAND OR 97205 ryan@oregoncub.org
CLAIRE VALENTINE-FOSSUM **(C)** OREGON CITIZENS' UTILITY BOARD	610 SW BROADWAY STE 400 PORTLAND OR 97205 claire@oregoncub.org; dockets@oregoncub.org
PORTLAND GENERAL ELECTRIC	
KIM BURTON **(C)** PORTLAND GENERAL ELECTRIC	121 SW SALMON STREET PORTLAND OR 97204 kim.burton@pgn.com
JAKI FERCHLAND **(C)** PORTLAND GENERAL ELECTRIC	121 SW SALMON ST. 1WTC0306 PORTLAND OR 97204 jacquelyn.ferchland@pgn.com
SHAY LABRAY **(C)** PORTLAND GENERAL ELECTRIC	21 SW SALMON STREET PORTLAND OR 97204 shay.labray@pgn.com; pge.opuc.filings@pgn.com
STAFF	
STEPHANIE S ANDRUS **(C)** Oregon Department of Justice	BUSINESS ACTIVITIES SECTION 1162 COURT ST NE SALEM OR 97301-4096 stephanie.andrus@doj.oregon.gov
ANNA KIM **(C)** PUBLIC UTILITY COMMISSION OF OREGON	P O BOX 1088 SALEM OR 97308 anna.kim@puc.oregon.gov

CASE: UE 452
WITNESS: ANNA KIM

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 100

REDACTED
Opening Testimony

June 23, 2025

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

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

Q. Please describe your educational background and work experience.

A. My Witness Qualifications Statement is found in Exhibit Staff/100.

Q. What is the purpose of your testimony?

A. My testimony covers several topics. First, as Staff's summary witness, I will present an overview of PGE's 2026 Annual Power Cost Update (APCU) filing and provide an overview of the issues reviewed by Staff in this filing, including a summary of the adjustments and recommendations made by Staff.

The second section of my testimony addresses PGE's compliance with the APCU guidelines and orders resulting from the most recent 2025 APCU, and contracts.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared Exhibit Staff/101: Witness Qualifications Statement.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Overview of 2026 APCU 2
CONF Figure 1. Actual and forecast power costs by major cost category 5
CONF Table 1. forecast power cost difference 6
Issue 1. Compliance with Past Orders and Guidelines 10
Issue 2. Capacity and Energy Contracts 15

OVERVIEW OF 2026 APCU

Q. What is PGE's APCU?

A. PGE's APCU (sometimes referred to as the Automatic Update Tariff (AUT)) is found in PGE Schedule 125 and is an automatic adjustment mechanism. Under Schedule 125, PGE must file an annual updated forecast of its Net Variable Power Costs (NVPC) no later than April 1 for rates that will be effective January 1 of the following calendar year. Schedule 125 is prescriptive as to what NVPC inputs are updated in each April filing. Schedule 125 also states PGE will update the inputs to forecasted NVPC no later than October 1 and will update some of the inputs, i.e., new power purchase or sales agreements, power and gas price projections, and new fuel contracts, on November 6 of each year. PGE's final forecast to NVPC is filed on November 15.[1] The November 15 Final Update includes the updated inputs from the October 1 and November 6 filings, and includes final updates to a few inputs, notably including anticipated on-line dates for new Qualifying Facilities (QFs).

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

A. Staff's review has focused on the main expenses forecasted by the Company and the modeling changes the Company has proposed.

Q. Is the current 2026 power cost forecast impacted by past choices by the Company?

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[1] Schedule 125 specifies that if November 6 or 15 falls on a weekend, the filing date is the next business day.

A. Yes. The resources the Company has procured and the risks it has incurred impact current power cost projections

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

A. In **Staff/100**, I provide an overview of the filing, a review of the Company's consistency with Commission orders, and discuss capacity and energy contracts.

In **Staff/200**, witnesses David Abraham addresses load forecasting, rate spread, rate design, and hydro modeling.

In **Staff/300**, witness Julie Dyck addresses updates to the Company's APCU filing related to energy markets, market purchases and sales, treatment of the Washington Climate Control Act, and federal tariffs.

In **Staff/400**, witness Bonnie Gariety addresses transmission issues.

In **Staff/500**, witness Zhuoyi Zhao, Ph.D., addresses the Western Energy Imbalance Market (WEIM) and the Extended Day Ahead Market (EDAM).

In **Staff/600**, witness Charles Lockwood addresses the Seaside battery system and the Natural Gas Call Option.

In **Staff/700**, witness Luz Mondragon addresses interactions with the integrated resource plan and resource procurement.

In **Staff/800**, witness Madison Bolton addresses reliability constraint events and capacity constraint modeling.

Q. Please summarize the Company's initial filing.

A. The Company has forecasted 2026 Net Variable Power Costs (NVPC) of $1,059.7 million, representing an increase of approximately $84.8 million. Adjusted for load, the increase is $50.6 million. On a per-unit basis, the Company's NVPC forecast is $48.3/MWh, which is $2.67/MWh more than the forecast in the November 15, 2024 filing.[2] While the November 15, 2024 filing included Clearwater Wind and Seaside, these two resources were removed in the final compliance filing in UE 436. However, the power costs PGE recovered for 2025 ultimately did assume the inclusion of Clearwater Wind, when the entire revenue requirement for Clearwater, including NVPC, was recovered under Schedule 122 in 2025.

PGE's AUT forecast for 2026 includes Clearwater that began commercial operation in January 2025. It also includes the Seaside battery that is scheduled to be on-line mid-year 2025.

Q. What does PGE say are the primary causes for the change in power costs?

A. The Company predicts an increase of $24.6 million related to BPA transmission costs and a $16.4 million increase due to federal tariffs on gas imports from Canada.

Q. How have individual cost categories changed between November 2024 and April 2025?

A. Based on the Company's filing in confidential document "WorkPaper_Table 1_CONF.xlsx", **[BEGIN CONFIDENTIAL]** [redacted]

2 PGE/100, Outama–Pedersen/2.

[redacted] **[END CONFIDENTIAL]** and which shows the impact of this power cost forecast, including BPA transmission and federal tariffs, the biggest changes are **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** as seen in confidential Figure 1.

CONF FIGURE 1. ACTUAL AND FORECAST POWER COSTS BY MAJOR COST CATEGORY

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

The following table was provided by the Company in “WorkPaper_Table 1_CONF.xlsx”.

CONF TABLE 1. FORECAST POWER COST DIFFERENCE

[BEGIN CONFIDENTIAL]

Summary Table
Forecast Power Cost Difference 2025 vs. 2026 ($ Millions)

Factor	Effect ($M)
Hydro Cost and Performance	[redacted]
Coal Cost and Performance	
Gas Cost and Performance	
VER and Owned Battery Cost and Performance	
Contract and Market Purchases	
Market Purchases for Load Increase	
Transmission	
Total	

[redacted]

[END CONFIDENTIAL]

Q. What is MONET and how does PGE use it in the 2026 AUT?

A. MONET, which is an acronym for Multi-area Optimization Network Transaction model, is an economic dispatch model developed by PGE and used to forecast Net Variable Power Cost (NVPC). MONET seeks to minimize NVPC by economically dispatching PGE's generating resources, subject to operating constraints, and making market purchases and sales. Generally, MONET dispatches a resource when it is available and its dispatch cost is below the electric market price, meaning that PGE's resources are dispatched when doing so would prevent a relatively expensive purchase or allow for a cost-saving sale of electricity. MONET uses a variety of inputs, including an hourly load forecast, operating characteristics of PGE's generation and storage facilities, contract information, transmission costs, and forward price curves for gas and electric power purchases and sales. MONET uses these inputs to simulate the dispatch of PGE resources and produce a forecast of NVPC and energy production for the Test Year.[3]

Q. What modeling changes to MONET has the Company proposed for the 2026 APCU?

A. The Company proposes modeling changes to address BPA tariff rates, federal tariffs, capacity market constraints, Beaver oil fuel stock, extended Colstrip operations in alignment with the 2023 IRP that was acknowledged in Order No. 24-096, EDAM, ongoing deferral of Washington Cap and Invest costs, hydro modeling corrections, Westside gas correction, NW Natural Call Option, and miscellaneous model maintenance.[4]

Q. Are additional model updates expected?

A. Yes. The Company intends to update the following in its July 15 update: power, fuel, emissions control chemicals, transportation, transmission contracts, and related costs; gas and electric forward curves; planned thermal and hydro maintenance outages; load forecast; wind and hydro production tax credit rates; and make any errata corrections to this initial filing. [5]

Q. Are further updates expected in the docket?

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3 PGE/100, Outama-Pedersen/6-7.
4 PGE/100, Outama–Pedersen/9.
5 PGE/100, Outama–Pedersen/42.

A. Yes. As discussed above, PGE files updates to its projected NVPC no later than October 1, and on November 6 and November 15.[6]

Q. Has Staff proposed any adjustments?

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

1. A reduction of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** representing an increase in forecast EIM benefits as described in **Staff/500, Issue 1**.
2. A reduction of $1.0 million representing an increase in forecast EDAM benefits as described in **Staff/500, Issue 2**.
3. A reduction of $4.2 million representing the withheld marginal resource as described in **Staff/800, Issue 1**.
4. A reduction of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** to remove the Reliability Contingency Event forecast as described in **Staff/800, Issue 2**.

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

A. Staff's proposed cumulative adjustments result in a reduction of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** to NVPC.

Q. Does Staff have other requests for the Company?

A. Yes. Staff recommends the Company:

[6] *See e.g., In the Matter of Portland General Electric, 2010 Annual Power Cost Update*, UE 208, Order No. 09-433 (October 30, 2009).

1. Provide relatable information about monetary changes to major power cost categories and how these affect existing rates, as described in **Staff/100, Issue 1**.
2. Provide additional information on real power losses capacity rate as described in **Staff/400, Issue 2**.
3. Propose a revision to the EIM benefits model for the next AUT that helps improve forecast accuracy and hold a workshop discussing the revised model prior to the 2027 AUT as described in **Staff/500, Issue 1**.
4. Explain its strategy to address its capacity deficit and model the impact of this strategy, as well as modeling its first proposed strategy of securing capital agreements as described in **Staff/800, Issue 1**.
5. Consider transitioning away from MONET to a different model as described in **Staff/800, Issue 1**.

Q. Did Staff review other topics that are not covered specifically in Staff testimony?

A. Yes. Staff reviewed numerous aspects of the Company’s filing, including coal generation, gas generation, Westside Gas updates, wind generation, PURPA forecast, hedging, and other MONET updates. While Staff does not have recommendations on these topics at this time, Staff’s investigation is ongoing, notably with the upcoming July Update.

ISSUE 1. COMPLIANCE WITH PAST ORDERS AND GUIDELINES

Q. What are minimum filing requirements (MFRs)?

A. MFRs are the filing requirements for PGE on NVPC established in Order No. 08-505. The Company has shared the MFRs its Exhibit 101. These filing requirements include summary documents, modeling enhancements, new item inputs, and miscellaneous items.

Q. Has the Company provided the MFRs as listed in Order No. 08-505?

A. Staff has reviewed the Company's MFR filing and believes that the Company has thus far complied with the MFR requirements. Part of the guidelines dictate what the Company can and cannot update over the pendency of the AUT, and as such, Staff cannot conclude that the Company has completely satisfied all requirements as the AUT docket is ongoing.

Q. What were the compliance implications of the 2025 APCU Order?

A. Order No. 24-406 includes two provisions pertinent to the 2026 AUT:

- The following parameters apply to the 2021 RFP battery projects for purposes of the 2026 NVPC forecast: a) round trip efficiency factor of 88.5 percent and b) Availability factor of 95 percent.
- Stipulating parties have the right to challenge the prudence of the Calpine Capacity contract.

Q. Did PGE comply with this order?

A. Yes.

Q. Are there implications from Order No. 25-075 from PGE's Renewable Automatic Adjustment Clause proceeding concerning the Clearwater resource?

A. Yes. Under that order, PGE is required to use a static capacity factor to calculate power costs in its AUT for five years starting in 2025. PGE will calculate its net variable power costs assuming that 80 percent of its nameplate capacity had been covered by long-term firm transmission, as was required in its RFP. The intention of this condition is to protect customers from the costs of potential transmission shortfalls, thus we clarify that the costs of this incremental transmission (the additional transmission needed to reach 80 percent) should not be charged to customers in the AUT in implementing this condition. PGE will hold the cost of the first 10 MW of short-term transmission rights used to deliver power from Clearwater to its load at any given time out of the PCAM or any other cost recovery docket. Whenever Clearwater is unable to deliver generated power to PGE's load due to lack of available transmission, it will exclude any marginal power costs incurred to cover this shortfall from the results of the PCAM.[7]

Q. Did PGE comply with Order No. 25-075?

A. Yes.

Q. Are there implications from Order No. 24-454 from the last General Rate Case?

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[7] *In the Matter of Portland General Electric Company, Renewable Resource Automatic Adjustment Clause (Schedule 122) (Clearwater Wind Project)*, Order No. 25-075 (February 21, 2025).

A. Yes, there are some implications for this docket.

- The Company is required to provide an analysis to justify keeping a minimum balance of 1.2 million dth of gas at North Mist and may do so in the context of a workshop in the AUT.[8]
- The Company is required to include a high-level non-confidential summary of their power cost forecasts that will allow better communication of expected rate changes to customers by PGE and other stakeholders. The Commission also expects “robust communication throughout the rate base process.” [9]

Q. Did PGE provide an analysis regarding keeping a minimum of 1.2 million dth of gas at North Mist?

A. Yes. PGE held a gas storage workshop on March 17, 2025. In its Direct Testimony, the Company discussed increasing the minimum reserved at North Mist.[10] Please see Staff/600, Issue 2 for discussion on this topic.

Q. Did PGE include a high-level non-confidential summary of its power cost forecast that will allow better communication of expected rate changes to customers by PGE and other stakeholders?

A. Staff does not believe so. Some information was provided, but as described above, less detail was available than in previous initial filings.

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8 *In the Matter of Portland General Electric Company, Request for a General Rate Revision,* UE 435, Order No. 24-454 at 21 (December 20, 2024).

9 Id., at 124.

10 PGE/100, Outama–Pedersen/9.

Q. Are there challenges in communicating high level impacts due to the lack of publicly available information?

A. Yes. The Company usually protects even high-level changes by major cost category, especially with later updates closer to the rate effective date. This year, it seems there is even less non-confidential information available than previously. For example, the following table is an example of a comparison the Company typically provides as non-confidential in an APCU. This table, and discussion about changes to these high-level categories, is absent in the Company's initial filing this year.

Table 1: Example of a past table provided by PGE comparing power costs between the 2025 APCU and UE 427 Forecast dated December 8, 2024.[11]

Forecast Power Cost Difference 2024 vs. 2025 ($ Millions)

Factor	Effect ($M)
Hydro Cost and Performance	$ (22.0)
Coal Cost and Performance	0.7
Gas Cost and Performance	(22.4)
2024 GRC Stipulation	14.5
VER and Owned Battery Cost and Performance	10.8
Contract and Market Purchases	37.8
Market Purchases for Load Increase	27.6
Transmission	(10.5)
Total	**$ 36.5**

** Numbers may not total due to rounding.*

Staff notes that this table still does not provide much detail for the public. While this table from the last AUT is more than was provided in this filing, it was still very scanty information for the public.

Q. Does this level of confidentiality impact other Staff testimony?

[11] Docket No. UE 436, PGE/100, Schwartz–Outama–Cristea/24, Table 1.

A. Yes. There are many areas within Staff's Opening Testimony where Staff must redact information that many may considered basic.

Q. Does Staff have any recommendations related to compliance with orders?

A. Staff believes PGE can do a better job at providing more non-confidential information in an accessible way. Particularly, Staff recommends that PGE provide relatable information about monetary changes to major power cost categories, and to increase transparency on how rates are changing, rather than relying solely on comparisons between forecast models. The public should be able to ascertain both how much, and why rates are changing, in the direct testimony. Staff recommends PGE implement more transparency when addressing the July Update in Reply Testimony.

ISSUE 2. CAPACITY AND ENERGY CONTRACTS

Q. How have changes to contracts impacted the resources in power costs?

A. When comparing the April forecast for 2026 to the 2025 forecast from November 2024, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[12]

Q. Did Staff review the new electric sale contracts since the 2025 AUT?

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

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12 PGE's WorkPaper_Table 1_CONF.

13 PGE's UE 452_CONF_PGE MONET Update 04152025_Attachment 1_04162025,, Vol 5 - Contracts.

[END CONFIDENTIAL] While this placeholder seems reasonable at this time, Staff will review any final contacts that materialize.

Q. How was the Calpine capacity contract addressed in last year's AUT?

A. Order No. 24-406 addresses the Calpine capacity contract. PGE introduced this contract in its October Update. Because Parties had little time to review this contract, Parties agreed that the contract could be included in the final NVPC update but Parties would have the option to challenge the prudence of this contract within the 2026 AUT.

Q. Did Staff review the Calpine contract?

A. Yes. Staff reviewed the contract when originally provided by PGE last year, and reviewed PGE's documentation in MFR Volume 5 and its modeling. Staff does not see concerns at this time. Staff is however interested to learn about AWEC's perspective and will take AWEC's review into account.

Q. Does Staff have any recommendations?

A. No, not at this time. Staff will continue to consider contract changes currently in the model and ones that are added in the overall context of this proceeding and take the research of other stakeholders into account.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 452
WITNESS: ANNA KIM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualifications Statement

June 23, 2025

WITNESS QUALIFICATIONS STATEMENT

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

CASE: UE 452
WITNESS: DAVID ABRAHAM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 200

OPENING TESTIMONY

June 23, 2025

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

A. My name is David Abraham. I am a Senior Economist employed in the Energy Program 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 Qualifications Statement is found in Exhibit Staff/201.

Q. What is the purpose of your testimony?

A. To address Portland General Electric's (PGE or Company) Test Year load forecast, rate spread/rate design and forecasted hydroelectric generation for PGE's 2026 Annual Update Tariff (AUT) filing, UE 452.

Q. Did you prepare any exhibits for this docket in addition to Staff/201?

A. Yes. PGE's non-confidential responses to select data requests can be found in Exhibit Staff/202.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1. Load Forecast 2
Issue 2. Rate Spread/Rate Design 6
Issue 3. Hydroelectric Generation........ 9

ISSUE 1. LOAD FORECAST

Q. What is PGE's 2026 load forecast in this AUT filing?

A. PGE's initial 2026 load forecast is 23,211 GWh,[1] which represents a 4.1 percent increase compared to PGE's 2025 general rate case forecast of 22,298 GWh.[2] Both forecasts include deliveries to customers who opted out of PGE's cost-of-service rates for direct access.

Q. Does the increase in the load forecast translate into an increase in net variable power costs?

A. Yes. PGE estimates a rate increase of $50.6 million.[3]

Q. Did Staff analyze the major factors driving the increase?

A. Yes. PGE describes two primary factors driving the increase. The anticipated updates to BPA transmission rates result in a $24.6 million increase, and the tariffs announced by the federal government will impact the purchase of Canadian natural gas, resulting in a $16.8 million increase.[4] Staff notes that the investor-owned utilities that will be impacted have worked together to advocate for a reduction in BPA's proposed rate increase.[5]

Q. Does PGE use the same load forecast in the MONET model as it does for proposed revenues collected via Schedule 125?

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1 Staff/202, PGE response to Staff No. DR 040 at 2.
2 Docket No. UE 435, PGE/700, Riter – Greene/3.
3 PGE/100, Outama - Pedersen/2.
4 PGE/100, Outama – Pedersen/3.
5 PGE/100, Outama – Pedersen/12.

A. No. The 2026 load forecast included in the MONET model is 21,946 GWh,[6] which compares to the retail forecast included in Schedule 125 of 20,690 GWh. The difference between the 2026 retail load forecast compared to the MONET model is attributable to line losses, or the amount PGE needs to procure to serve load at the meter.[7]

Q. Does Staff agree the forecast used in the MONET model should be grossed up for line losses?

A. That depends. Schedule 125 represents load measured at the customer meter, reflecting values used for customer billing. Grossing up retail sales to account for line losses related to energy that flows on Company owned lines would be the right approach to accurately represent the energy needed to procure service at the meter. However, for energy that flows on BPA's transmission lines and requires a financial payment to make up for line losses, no gross up should be applied to the forecast used in the MONET model for those line losses.

Q. What is Staff's proposal regarding PGE's treatment of line losses in this filing?

A. Staff will work with the Company to ensure there is no double counting of line losses in this filing related to the gross up of the load forecast and energy procured via payments to BPA to account for line losses.

Q. Did Staff analyze the 2026 load forecast by customer class?

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6 PGE/100, Outama – Pedersen/10.
7 Staff/202, PGE/Response to Staff No. DR 069, at 3.

A. Yes. Table 1 displays PGE's 2026 energy deliveries by customer class compared to 2024 actuals.[8] The table includes PGE's energy deliveries on a cycle-month billing basis, including deliveries to customers who opted out of cost-of-service rates for direct access service.[9]

Table 1: PGE Energy Deliveries by Class

Customer Class	2026 Forecast (GWh)	2024 Actuals (GWh)	Change from 2024
Residential	7,905	7,723	2.4%
Commercial	6,931	6,976	-0.6%
Industrial	8,332	6,716	24.1%
Lighting	43	43	0%
Total	23,211	21,458	8.2%

Q. Did Staff analyze what is driving the increase in the 2026 forecast?

A. Yes. Nearly the entirety of the increase is attributed to the industrial class. The Company has described an expectation for strong growth from high-tech expansion and new data centers for the industrial class.[10] For example, PGE estimated a one-year increase of 9.2 percent for the industrial class (2024-2025) in the Company's most recent rate case filing.[11]

Q. Did Staff meet with the Company to discuss the forecasting methodology used in this filing?

A. Yes. Staff met with the Company's analyst and reviewed the workpapers to ensure that the methodology used in this AUT filing is consistent with the

8 Staff/202, PGE/Response to Staff No. DR 069, at 3.
9 Staff/202, PGE response to Staff No. DR 040 at 2.
10 Docket No. UE 435, PGE/700, Riter – Greene/3.
11 Docket No. UE 435, PGE/700, Riter – Greene/5.

methodology used in the Company's most recent general rate case.[12] In addition, Staff will continue discussions with the Company regarding the strong growth expected from new data center connections and usage in this filing compared to recent actuals.

Q. Does Staff recommend any adjustments to PGE's load forecast in this AUT filing?

A. No, not at this time.

[12] Staff/202, PGE response to Staff No. DR 040 at 1.

ISSUE 2. RATE SPREAD/RATE DESIGN

Q. Please describe how PGE spreads its Schedule 125 AUT Rates.

A. PGE spreads Schedule 125, the AUT rates, based on the generation revenue allocation as required in Special Condition 1 of Schedule 125:

> *Costs recovered through this schedule will be allocated to each schedule using the applicable schedule's forecasted energy on the basis of an equal percent of generation revenue applied on a cents per kWh basis to each applicable rate schedule.*

Q. Did Staff analyze the Company's use of generation revenue to spread rates to Schedule 125?

A. Yes. For example, PGE's residential (Schedule 7) customers have 43.1 percent of the forecasted base generation revenues in 2026 and are also assigned 43.1 percent of the AUT rates. Likewise, small commercial (Schedule 32) customers are assigned 7.3 percent of the AUT rates to match their 2026 forecasted base generation revenue share.

Q. What are the base rate impacts of the increase in Schedule 125 prices?

A. Table 2 summarizes the initial estimated 2026 cost of service (COS) base rate impacts by rate schedules.[13]

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[13] PGE/200, Ferchland – Manley/2.

Table 2: Estimated Base Rate Impacts

Schedule	Rate Impact
Sch 7 Residential	1.3%
Sch 32 Small Non-Residential	1.2%
Sch 83 Non-Residential	1.6%
Sch 85 Secondary	1.8%
Sch 85 Primary	2.4%
Sch 89 Primary	2.2%
Sch 89 Subtransmission	1.9%
Sch 90	2.4%
COS Overall	1.6%

Q. Does Staff have any concerns with PGE's Schedule 125 rate spread?

A. No. PGE's rate spread is consistent with the design of Schedule 201.

Q. Did Staff identify any rate design changes to Schedule 125 in this AUT filing?

A. Yes. To remain consistent with the pricing structure approved in UE 435, PGE now includes on-peak, mid-peak, and off-peak pricing structures in Schedule 125.

Q. Did Staff identify any changes to the calculation of AUT rates in this filing?

A. Yes. In UE 435, PGE changed Schedule 125 to include all costs of NVPC whether PGE filed for a full rate revision or an AUT. The 2026 AUT revenue requirement is now determined by calculating 2026 NVPC revenues at current rates and subtracting from the total forecasted 2026 proposed NVPC amount. PGE then multiplies the delta by the revenue sensitive factor from UE 435 of 3.5 percent to determine the incremental revenue sensitive amount needed.

Q. How does this methodology differ from prior AUT calculations?

A. In prior years, Schedule 125 pricing was calculated as the change in the proposed NVPC compared to the current NVPC with the addition of the revenue sensitive factor.

Q. Does Staff have a recommendation regarding this change?

A. Staff agrees that the proposed change more clearly delineates the base price change from NVPC price changes.

Q. Does Staff propose any adjustments to PGE's initial 2026 Rate Spread calculation?

A. No, not at this time.

ISSUE 3. HYDROELECTRIC GENERATION

Q. Please summarize how PGE produces its hydroelectric forecast.

A. PGE describes the use of a 10-year average of actual hydro generation as a basis for the forecast, adjusted for known and verifiable climatological indicators for the upcoming water year.[14]

Q. Has PGE recently made any changes to its hydroelectric forecast methodology?

A. Yes. The Company discontinued the use of the Northwest Power Pool's 80-year Headwater Benefits Study in favor of the 10-year average of actual hydro generation in last year's 2025 AUT filing.

Q. Has the change improved PGE's hydro generation forecast?

A. It may be too early to determine if the change to a 10-year average has improved hydro forecasting results.

Q. Is PGE proposing any changes to their hydro methodology in this filing?

A. Yes. PGE proposes rolling forward the 10-year data set to remove the oldest year and include the most recent full year of actuals. Additionally, PGE has discovered some issues in the assumptions utilized in last year's forecast and Table 3 summarizes the Company's proposed updates to hydro generation modeling:

[14] UE 436/100, Schwartz – Outama - Cristea/12.

Table 3. PGE Hydroelectric Modeling Corrections

Issue	Description	Impact to NVPC (Millions)
Canadian Entitlement	Correction due to EIA data mis-interpretation regarding the 10-year average of hydro generation data.	$ 3.1
Canadian Encroachment	Similarly, PGE also removing Encroachment energy from Mid-C generation.	$ 3.4
Columbia River Treaty	Modeling a 33% reduction to Canadian Entitlement obligations due to a pending Columbia River Treaty Agreement.	$ (1.4)
Habitat and Fish Flow	Removing downward flow adjustments related to winter flood, Farady dam diversion, and hatchery diversion requirements.	$ (2.5)
Total NVPC Impact		$ 2.6

Q. Does Staff have any concerns with PGE's proposed changes to hydro modeling?

A. Staff does not have any concerns regarding PGE's proposal to roll the 10-year average forward to include the most recent full year of actuals. Regarding PGE's remaining proposed corrections and updates:

1. <u>Canadian Entitlement and Encroachment</u>: PGE assumed that the U.S. Energy Information Administration (EIA) hydro generation data used to establish the 10-year average had already removed the Canadian Entitlement and Encroachment obligations; however, these obligations had not been removed from the EIA 10-year average. Staff agrees the correct methodology would be to remove these obligations from PGE's estimated AUT energy supply.

2. Columbia River Treaty: Canada and the U.S. reached an Agreement-in-Principle (AIP) on key elements of a modernized Columbia River Treaty. PGE plans to model a 33 percent reduction to the Canadian Entitlement energy to reflect the AIP. Staff is concerned that the litigation is still pending, and volumes are subject to change. Staff will reserve a final decision on this issue until more clarity is developed.
3. Habitat and Fish Flow: PGE describes several downward adjustments related to spill and diversion dam flow requirements and hatchery diversion requirements. PGE proposes to remove these downward adjustments from its NVPC energy supply as the 10-year average data used to model hydro generation would already account for these historical effects. Staff agrees that PGE's proposal to remove these downward adjustments is prudent and results in a more accurate representation of future hydro generation volumes.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 452
WITNESS: DAVID ABRAHAM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 201

Witness Qualifications Statement

June 23, 2025

WITNESS QUALIFICATION STATEMENT

NAME: David Abraham

EMPLOYER: Public Utility Commission of Oregon

TITLE: Energy Costs Section Economist
Rates, Safety and Utility Performance Program

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

EDUCATION: Master of Science, Economics (2013)
University of Texas,
El Paso, TX

Bachelor of Arts, Business Administration
(2005)
University of Texas,
El Paso, TX

EXPERIENCE: I have been employed by the Oregon Public Utility Commission as an economist in the Energy Costs Section since November 2023. Prior to working for the Commission, I worked for an Investor-Owned Regulated Electric Utility in Texas for the past 14 years. I started with the utility as a real-time energy trader and transitioned into the Investor Relations Department as a Financial Analyst in 2012. I moved to a position as an energy and demand forecaster in the Regulatory and Resource Planning Department in 2019 and was named lead-forecaster in May of 2021. I attended an electric utility ratemaking course offered through New Mexico State University and the Center for Public Utilities in 2019.

CASE: UE 452
WITNESS: DAVID ABRAHAM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 202

PGE’s Responses to Select Data Requests

June 23, 2025

May 23, 2025

To: Scott Gibbens
Oregon Public Utility Commission

From: Jaki Ferchland
Senior Manager, Pricing, Tariff, and Power Cost Recovery

Portland General Electric Company
UE 452
PGE Response to OPUC Data Request 040
Dated May 9, 2025

Request:

Please provide:

a. A narrative describing any changes in the retail energy forecast methodology used in this filing compared to PGE's UE 435 General Rate Case, and
b. Actual retail energy deliveries to customer classes in 2024 and forecasted energy deliveries for 2025 through 2026 at average weather conditions using the table format below:

MWh Retail Energy Deliveries			
	2024 Actual	2025 Forecast	2026 TY Forecast
Residential			
General Service			
Industrial			
Lighting			
Total Retail			

Response:

a) No methodological changes were made compared to UE 435 filing. Final rate spread for 2025 was based on the September 2024 Load Forecast. The September 2024 Load Forecast was also used for Test Year 2026 in UE 452.

b)

MWh Retail Energy Deliveries (Cycle)			
	2024 Actual	2025 Forecast	2026 TY Forecast
Residential	7,723,120	7,885,158	7,905,059
General Service (Secondary Service)	6,975,873	6,971,207	6,931,022
Industrial	6,716,419	7,544,960	8,332,363

(Primary and Sub-Transmission Service)			
Lighting	42,624	42,585	42,621
Total Retail	21,458,035	22,443,911	23,211,065

PGE's energy deliveries are on a cycle-month (billing) basis, including deliveries to customers who opted out of PGE's cost-of-service rates for direct access. The 2025 and 2026 forecasts reflect economic conditions expected for Oregon at the time of forecast development, as well as operational changes among PGE's largest customers, savings from incremental energy efficiency (EE) programs that are implemented by the Energy Trust of Oregon (ETO) and forecasted incremental electric vehicle adoption, building electrification and customer-sited solar generation. Note, the 21,946 MWh cost-of-service energy forecast included in MONET for the 2026 test year excludes deliveries to direct access customers, reflects the calendar year, and is grossed-up for line losses prior to being input into the model.

June 2, 2025

To: Scott Gibbens
Oregon Public Utility Commission

From: Jaki Ferchland
Senior Manager, Pricing, Tariff, and Power Cost Recovery

Portland General Electric Company
UE 452
PGE Response to OPUC Data Request 069
Dated May 19, 2025

Request:

Please provide a narrative describing the difference in the 2026 retail load forecast between:

a. PGE/100, Outama - Pedersen/10 at 8, compared to
b. PGE/201, Ferchland – Manley/1, 2026 Calendar COS Energy.

Response:

The difference between the 2026 retail load forecast presented in PGE/100 as compared to PGE/201 is a gross up for line losses. PGE/201 presents load measured at the customer meter, reflecting the load values comparable to those used for customer billing. PGE/100 presents the grossed-up load, or the amount PGE needs to procure to serve load at the meter.

The line losses used for this gross up calculation are consistent with the loss adjustment factors in PGE's most recent line loss study, approved in UE 394. These adjustment factors are as follows:

- Secondary Delivery Voltage: 6.4%
- Primary Delivery Voltage: 5.3%
- Subtransmission Delivery Voltage: 4.16%.

Loss adjustment factors are also listed in relevant tariff schedules, within Non-Cost of Service Option language. See Schedule 89 as an example.

CASE: UE 452
WITNESS: JULIE DYCK

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 300

REDACTED
OPENING TESTIMONY

June 23, 2025

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

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

Q. Please describe your educational background and work experience.

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

Q. What is the purpose of your testimony?

A. My testimony analyzes the treatment of costs for the Washington cap and invest program and PGE's updates to market purchases and sales, market forecasts, and tariffs included in Portland General Electric's (PGE) Automatic Update Tariff (AUT). At this time, Staff does not have any monetary adjustments related to the topics covered in this exhibit.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared Exhibit Staff/302, comprised of PGE's non-confidential responses to Staff data requests and Exhibit Staff/303, which includes PGE's confidential responses to data requests.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1. Washington Cap and Invest 3
Issue 2. Gas and Electric Market Forecast 7
Figure 1. Mid-Columbia Spot Prices 10
Confidential Figure 2. Electric Official Forward Price Curve: 11
Figure 3. Natural Gas Spot Prices 13
Confidential Figure 4. Natural Gas Official Forward Price Curve 14

Issue 3. Market purchases and Sales 16
Confidential Figure 5. Historical Purchases 20
Confidential Figure 6. Historical Sales 21
Issue 4. Tariffs 22

ISSUE 1. WASHINGTON CAP AND INVEST

Q. What is the Washington Climate Commitment Act (CCA)?

A. The state of Washington passed the Climate Commitment Act (CCA) in 2021 aimed at reducing pollution and achieving greenhouse gas (GHG) limits set in Washington state law. It is one of a suite of laws intended to drive down greenhouse gas emissions in Washington to 45 percent below 1990 levels by 2030, 70 percent by 2040, and 95 percent by 2050. The Washington Department of Ecology (Ecology) finalized the CCA regulations in October 2022 and the program was launched on January 1, 2023, and entities covered under the program started incurring emission compliance obligations then.[1] In November 2024, Washington voters rejected initiative 2117, which sought to repeal the CCA and dismantle the cap-and-invest program.

Q. What is the Washington cap and invest program?

A. This program is the primary mechanism established by the CCA. It sets a declining cap on total carbon emissions and requires major polluters to purchase allowances for their emissions that are equal to their total annual GHG emissions if they are a covered entity. Each allowance permits the emissions of one metric ton of CO_2e. Allowances can be obtained several ways including through auctions, secondary markets, offset credits, and free allocations. PGE must comply with requirements with respect to energy imported into the State of Washington.

[1] Cap-and-invest - Washington State Department of Ecology which was accessed at https://ecology.wa.gov/Air-Climate/Climate-Commitment-Act/Cap-and-invest.

Q. Has treatment of PGE's cap and invest program costs been addressed by the Commission in previous proceedings?

A. Yes. In PGE's 2023 general rate case, the Commission approved a stipulation specifying:

1. Parties agree that PGE will remove the estimated carbon compliance costs associated with the Washington CCA from the 2024 NVPC forecast.
2. Parties agree that PGE will submit, and Parties will not oppose, a deferral application under ORS 757.259(2)(e) to defer 2024 carbon compliance costs associated with the Washington CCA.
3. Parties agree that if PGE seeks to amortize any deferred amounts under ORS 757.259(5), it will request amortization through Schedule 125.
4. Although Parties agree to support PGE' s deferral of Washington CCA costs, this agreement does not mean the Parties will necessarily support the amortization of those costs. Parties reserve the right to challenge the amortization of the costs and raise issues when PGE requests amortization of deferred amounts.[2]

Q. Has PGE continued the treatment of the cap and invest costs agreed to for the 2024 AUT?

A. Yes. PGE did not include an estimate of the costs within the 2025 AUT. Instead, the Company separately filed for reauthorization of its deferred

[2] *In the Matter of Portland General Electric Company, Request for a General Rate Revision*, UE 416, Order No. 23-386, Att., Third Partial Stipulation at 3 (October 30, 2023).

accounting application in Docket UM 2308 to cover the period of January 1, 2025 through December 31, 2025.[3]

Q. Why did stipulating parties recommend a deferral in 2023?

A. Deferring the costs allows PGE to track and (potentially) recover actual Washington CCA-related compliance costs-if and when they materialize-rather than relying on uncertain costs in its AUT. However, the expenses are to be ultimately amortized in the AUT. It also ensures that customers are only charged for prudent, verified expenditures, as all deferred balances remain subject to a prudency review by the Commission. In 2023 and 2024, PGE has not included any Washington CCA cost costs in its deferral. Therefore, no prudency reviews of amortized amounts have been completed.

Q. Does Staff have any recommendation to the Company as of now related to its compliance costs?

A. No. At this time, Staff does not oppose the deferral. Staff will reevaluate the need for a deferral in the next AUT.

Q. Are there additional concerns that Staff should remain aware of for future filings?

A. Yes. Staff should continue to monitor any material changes in the Washington CCA policy, the accuracy and transparency of PGE's deferred cost tracking, and potential rate impacts once PGE seeks amortization of the deferred balance. One pending change that was highlighted by the Company is the

[3] PGE/100, Outama—Pedersen/24.

linkage rulemaking.[4] If approved, this would mean that all importers of unspecified electricity will need to be covered entities (and therefore need to acquire allowances) regardless of the amount of unspecified electricity the entity imports.[5] As a result, PGE could be responsible for paying the carbon costs for each metric ton of unspecified electricity imported into Washington. PGE has submitted separate comments to Ecology (along with PacifiCorp and other Companies).[6] Currently the threshold is 25,000 metric tons of CO_2e and in 2023, PGE did not report applicable emissions greater than this threshold.

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4 These were first outlined in an industry supported paper known as the Electric Power Entities (EPE) Under the Climate Commitment Act (CCA) ("White Paper"). Letter from Joint Parties to Ecology, 23-02-051, (June 2023).

5 Referred to as the Linkage rulemaking which is currently in process and could last until early 2026. This can be accessed online at https://ecology.wa.gov/regulations-permits/laws-rules-rulemaking/rulemaking/wac-173-441-446-cap-and-invest-program-updates-and-linkage. The linkage aims to create a unified carbon market between Washington, California, and Quebec.

6 PGE's comments are included in Staff/302 and can be accessed online at https://ecology.commentinput.com/comment/extra?id=KZc7tHYhu.

ISSUE 2. GAS AND ELECTRIC MARKET FORECAST

Q. Explain the electric and gas forward curves used by PGE.

A. There are four forward curves used by MONET, either directly or in development of its inputs: electric, gas, oil, and foreign exchange (F/X) rate. For this initial filing of the 2026 AUT, the electric, gas, heating oil, and F/X curves are as of February 28, 2025, and will continue to be updated, with the final update occurring in November before rates go into effect.[7]

Q. Please describe how the Company's gas and electricity official forward price curves are derived.

A. Gas and power forward price curves are developed starting with price data delivered from term traders transacting in the open markets and from various third-party data providers including brokers, and proprietary price publications. The Company uses price data from the following sources: **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[8]

This third-party data is aggregated then compared against the forward prices provided by term trading to develop a separate final forward price curve data set. The final forward price curves are then adjusted to be within 5 percent of the third-party price data, ensuring prices are not off market. Forward price curves are reviewed daily by risk management. These final price curves

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7 ^_2026AUTElectricAndGasCurves.docx. This file is uploaded as part of the workpapers submitted to the Commission as part of the Company's initial and subsequent filings.

8 Staff/303, PGE's CONF Response to DR 4 (pdf).

are then automatically sent to the Company's system-of-record to be used as the official forward price curve.[9]

Q. How do market forecasts show up in the Company's workpapers?

A. Hourly forward electric and gas prices as of February 28, 2025, are included and formatted for MONET input from the monthly prices. In general, this price information, as stated above comes from the Company's risk management team.[10] Then an hourly shape is applied as an outboard adjustment.[11] California-Oregon border transactions (2022-2024) are analyzed separately by the Company by applying Lydia shaped prices to the expected volumes and prices for the Test Year.[12]

Q. Please describe in more detail what Lydia is.

A. Lydia is an hourly price shaping model used to create hourly price distributions from forward (monthly) on and off-peak prices to support the NVPC forecast in MONET. It was developed in 2001 and is an outboard adjustment to MONET that applies an hourly shape to the monthly on/off-peak electric curve. Lydia 2.0 was updated during the 2022 AUT to incorporate wind volatility and its impact on intramonth Mid-Columbia (Mid-C) prices, making wind generation and Mid-C price forecasting an interdependent process. Lydia 2.2 was further refined in the 2023 AUT and was intended to better align with actual historical

[9] Staff/302, PGE's Response to DR 3 (pdf).

[10] 2_2026EndurCurves-20250228_FA. This file is uploaded as part of the workpapers submitted to the Commission as part of the Company's initial and subsequent filings.

[11] Lydia2.2_2026AUT_20250228. This file is uploaded as part of the workpapers submitted to the Commission as part of the Company's initial and subsequent filings.

[12] 6_COB2022-24WeightedShape_2.28.2025. This file is uploaded as part of the workpapers submitted to the Commission as part of the Company's initial and subsequent filings.

shapes for Mid-C data.[13] Lydia 2.2 methodology is also used for the 2026 AUT.[14]

Q. Which market hubs does PGE use for wholesale electricity transactions?

A. The primary hubs are Mid-C and the California-Oregon Border (COB).

Q. Please describe the changes seen in wholesale electric prices in recent years.

A. After almost two decades of relatively little change, electricity consumption grew by two percent in 2024, and the EIA forecasts it will continue growing by two percent in 2025 and 2026, mostly as a result of demand from new semiconductor and battery manufacturing factories and from data centers.[15] Average wholesale electricity prices at major trading hubs were lower and less volatile in 2024 than in 2023.[16] This was mostly driven by low natural gas prices,[17] increases in generation for some lower cost renewable energy sources[18] and new battery storage capacity.[19] Still, as PGE correctly highlighted, prices spiked above $150/MWh twelve days in 2024, and these

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13 UE 436 Staff/200, Dyck/11 and UE 402 PGE/100, Vhora—Outama—Cristea/21.

14 See the Company's non-confidential workpaper titled ^_2025AUTElectricAndGasCurves. This file is uploaded as part of the workpapers submitted to the Commission as part of the Company's initial and subsequent filings.

15 Residential Energy Expenditures have increased with colder weather and higher prices (available at https://www.eia.gov/todayinenergy/detail.php?id=64584).

16 Wholesale Electricity Prices Trended higher in 2021 due to increasing natural gas prices (available at https://www.eia.gov/todayinenergy/detail.php?id=50798). See also U.S. Wholesale Electricity Prices were Lower and Less Volatile in 2024 (available at https://www.eia.gov/todayinenergy/detail.php?id=62544).

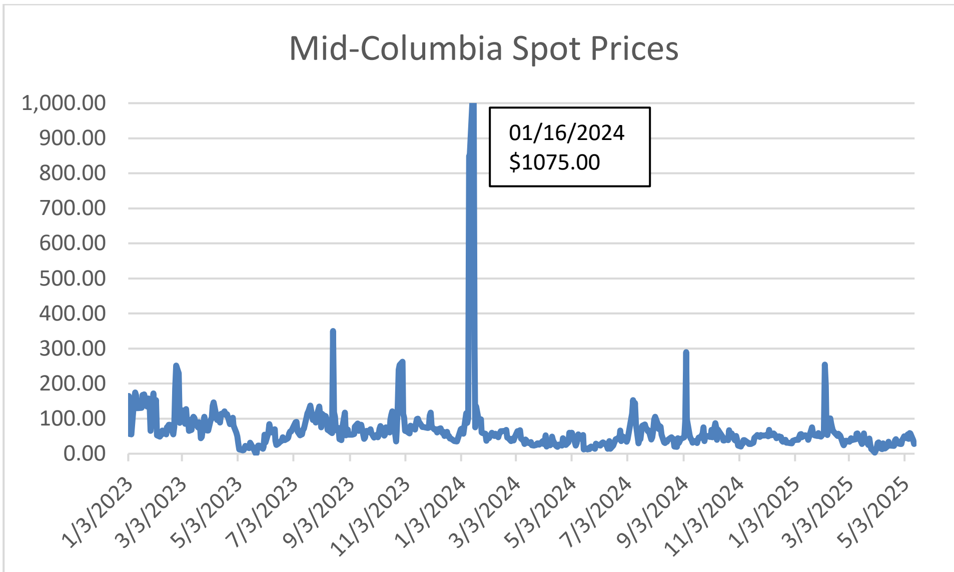
17 U.S. Wholesale Natural Gas Spot Prices Fell to Record Lows in First Half 2024 (available at https://www.eia.gov/todayinenergy/detail.php?id=62544).

18 Levelized Costs of New Generation Resources in the Annual Energy Outlook 2023 (available at https://www.eia.gov/outlooks/aeo/electricity_generation/pdf/AEO2023_LCOE_report.pdf)

19 Batteries are a Fast-Growing Secondary Electricity Source for the Grid (available at https://www.eia.gov/todayinenergy/detail.php?id=63025).

scarcity pricing days have been more common in the past decade compared to the decade prior.[20]

FIGURE 1. MID-COLUMBIA SPOT PRICES[21]



Q. What are forecasts projecting for 2026 wholesale natural gas prices?

A. US electricity prices in 2025 may continue to be moderate as strong natural gas production is expected to keep pace with growing LNG exports. However, in 2026 and beyond, prices may rise more steeply as a result of the imposition of US tariffs, counter-tariff actions by other countries, the ultimate response of the Federal Reserve, and unexpected geopolitical events. In combination, these could drive higher materials, energy, and capital costs for utilities, eventually impacting retail power rates.[22] The Company's current OFPC

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20 PGE/100, Outama—Pederson/17.
21 [CIQ Pro: Commodity Charting](#).
22 S&P Global Market Intelligence, 2024 US Electricity Price Growth Continues Moderation Trend Since 2022 Spike (accessible at https://www.capitaliq.spglobal.com/apisv3/spg-webplatform-core/news/article?id=88701856&KeyProductLinkType=65). This article is also included in Staff/302.

shows **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** The Company does not currently have forecasted COB prices but will update them in the July filing. As a result, the Company is currently using Mid-C curves as a proxy for COB prices. That is why they are not displayed separately in Confidential Figure 2.[23]

CONFIDENTIAL FIGURE 2. ELECTRIC OFFICIAL FORWARD PRICE CURVE: [24]

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. Where does PGE source its natural gas from?

A. PGE sources its natural gas supply from three regions, maintaining firm transportation rights to Sumas, AECO, and Opal.[25]

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23 ^_2026AUTElectricAndGasCurves.docx.

24 Created using data from Copy of 2_2026EndurCurves-20250228_FA.

25 Staff/302, PGE's Response to DR 16 (pdf). See PGE's Minimum Filing Requirements, Volume 5 – Contracts / Gas Transportation for details on the firm transportation rights PGE holds to transport physical gas purchases to its power plants. See also PGE/100, Outama-Pedersen/ testimony page 15, lines 1-11 and 16, lines 1-14.

Q. Please describe the changes in wholesale natural gas prices in recent years.

A. The Henry Hub natural gas price set numerous daily and monthly low-price records in 2024. On an inflation-adjusted basis, average monthly prices in February, March, April, and August were the four lowest ever recorded, and the four lowest daily prices ever recorded also occurred during 2024.[26] Prices at regional trading hubs decreased last year primarily because of relatively high natural gas inventories in each of the storage regions in 2023[27] and 2024,[28] sustained U.S. natural gas production,[29] and mild winter temperatures.[30]

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26 Spot Henry Hub Natural Gas Prices Hit a Historic Low in 2024 (accessible at https://www.eia.gov/todayinenergy/detail.php?id=64184).

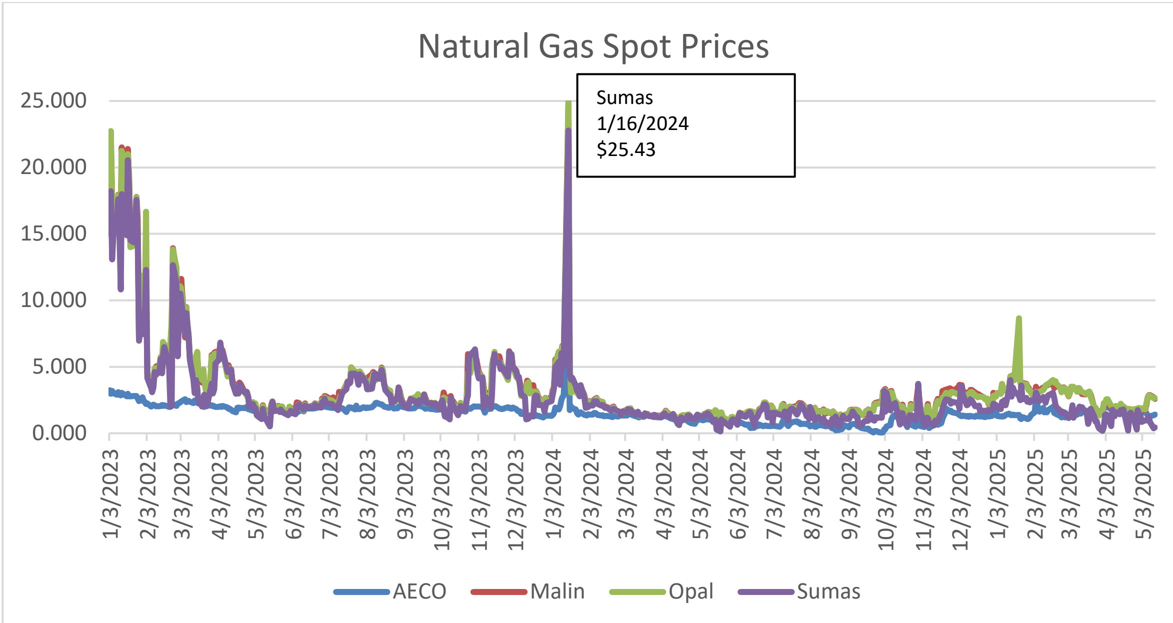
27 The United States Begins the Winter with the Most Natural Gas in Storage since 2020 (accessible at https://www.eia.gov/todayinenergy/detail.php?id=61044).

28 U.S. Inventories Enter the Winter with the Most Natural Gas since 2026 (accessible at https://www.eia.gov/todayinenergy/detail.php?id=63864).

29 EIA-914 Monthly Production Report (accessible at https://www.eia.gov/petroleum/production/#ng-tab).

30 The U.S. Has its Warmest Winter on Record (accessible at https://www.noaa.gov/news/us-had-its-warmest-winter-on-record).

FIGURE 3. NATURAL GAS SPOT PRICES[31]



Q. What are forecasts projecting for 2026 wholesale natural gas prices?

A. Natural gas prices are forecasted to increase from 2024 to 2026. This is due in part to the fact that LNG export capacity is on track to double between 2024 and 2028.[32] In other words, increases in total demand for natural gas are expected to outpace increases in supply in upcoming years. In the near-term, storage is lower than the five-year average due to colder than expected weather in 2025. Record output and milder weather in the spring should allow utilities to pull less gas out of storage in the coming weeks. However, the EIA expects increased demand both domestically and for exports contributing to sustained upward pressure on prices through 2026.[33]

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31 CIQ Pro: Commodity Charting.

32 North America's LNG Export Capacity is on Track to More than Double by 2028 (accessible by https://www.eia.gov/todayinenergy/detail.php?id=64128).

33 Short Term Energy Outlook (accessible at https://www.eia.gov/outlooks/steo/report/natgas.php).

[BEGIN CONFIDENTIAL] [redacted] **[END CONFIDENTIAL]**

CONFIDENTIAL FIGURE 4. NATURAL GAS OFFICIAL FORWARD PRICE CURVE[34]

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. Does Staff have any recommendation related to PGE's OFPCs discussed above at this time?

A. In general, Staff has reviewed the market forecasts and identifies no issues or recommendations for additional analysis or adjustments so far. However, this may be updated as a result of new information, internal discussions, other

[34] Created using data from Copy of 2_2026EndurCurves-20250228_FA.

intervenors' testimonies, or the Company's rebuttal testimony or subsequent updates.

ISSUE 3. MARKET PURCHASES AND SALES

Q. How are market purchases and sales included in the AUT?

A. Physical and financial contract and market fuel (coal, natural gas, oil) commodity and transportation costs are included as inputs to the MONET model. The same is true for physical and financial electric contract purchases and sales.[35] MONET simulates the dispatch of PGE's resources to meet load, which happens generally when dispatch cost is below the market electricity price. Then, MONET fills any resulting gap between total resource output and retail load with hypothetical market purchases (or sales) priced at the forward market price curve.

Q. Does PGE hedge its future energy requirements?

A. Yes, PGE supplements its own generation with power purchased in the wholesale market, utilizing short and long-term wholesale power purchase contracts. These purchases allow the Company to take positions in power and fuel markets up to five years in advance of physical delivery. PGE also uses spot purchases of power in the open market that are made under contracts that range in duration from 15 minutes to one month.

Q. How does PGE transact power?

A. PGE purchases and sells power in the open market under short and long-term contracts.

- Short term contracts involve transactions in the day-ahead and real-time trading markets, where delivery occurs within hours or days. These

[35] PGE/100, Outama—Pederson/6-7.

trades can happen bilaterally (directly between parties), via brokers, or through market platforms like CAISO's Day-Ahead and Hour-Ahead Markets and the Western Energy Imbalance Market (WEIM).[36]

- Long-term contracts typically involve forward purchases or sales with delivery over multiple years and are often secured through Request for Proposals (RFPs). Some of PGE's long-term transactions are planned for delivery starting in 2026, as reflected in the NVPC forecast.[37] Term contracts are discussed more below.

In addition to these short and long-term contracts, the Company also executes Qualifying Facilities (QF) contracts.

Q. What is the difference between physical and financial contracts?

A. Physical contracts involve the actual delivery of electricity or gas. In contrast, financial contracts are used for hedging (to protect against price fluctuations in the market).

Q. Does the Company include any physical or financial[38] electric contracts in its 2026 AUT?

A. No new electric physical contracts have been added since the 2025 AUT. For financial contracts, PGE includes monthly total marked-to-market (MTM'd) net costs.[39]

36 See also UE 391 Staff/200 Cohen/3.
37 Staff/302, PGE's responses to Staff DR 7 (pdf) and DR 11 (pdf).
38 These are fixed or index financial swap contracts, marked-to-market (MTM'd) at the 2/28/2025 electric curves.
39 #_2026AUTTermContracts.docx. These values are pasted into MONET on the PC Input worksheet in row 87.

Q. What are marked-to-market net costs?

A. This refers to the process of valuing a financial contract based on its current market value rather than the original cost or agreed upon price. In other words, if the current market price is worse than the contract price, it is a cost, if better, it might be a gain. The net of these values is reported by the Company.

Q. Can you provide an example?

A. If PGE locked in a contract where each MMBtu of gas was $5/unit, but the current market price is $4/unit, the contract would have a $1/unit loss. That loss is recorded as part of the Company's MTM net cost. This method ensures that cost estimates reflect current market projections—not outdated projections.

Q. What are the total forecasted costs as of the Company's Opening Testimony for its financial electric contracts?

A. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[40]

Q. Does the Company include any physical or financial gas contracts in its 2026 AUT?

A. Yes. PGE includes three term-gas physical contracts at Port Westward for 2026.[41] This appears to be added into the Company's weighted average cost of gas (WACOG). For financial gas contracts, PGE uses the same method as it does for electricity.[42]

Q. What are the total forecasted costs as of the Company's Opening Testimony for its physical and financial gas contracts?

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40 This is a sum of row 87 in the PC Input page.
41 Entered into MONET on the PC Input page in rows 107-108.
42 Monthly MTM'd net costs are entered into MONET on the PC input page in row 84.

A. The Company's physical gas contracts total **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[43] The Company's financial gas contracts total **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[44] These values appear reasonable as the EIA and other sources have shown that increases in natural gas prices expected for 2025 and 2026 compared to the all-time lows seen in 2024. Therefore, the Company would want to hedge more natural gas.

Q. How do purchases in the 2026 AUT compare to those in the past?

A. In this AUT, PGE forecasts that costs for purchased power to total **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

43 This is a sum of row 112 in the PC Input page.
44 This is a sum of row 84 in the PC Input page.

CONFIDENTIAL FIGURE 5. HISTORICAL PURCHASES[45]

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. How do sales in the 2026 AUT compare to those in the past?

A. In this AUT, PGE forecasts that revenues from sales for resale will total **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** See Confidential Figure 6.

[45] Staff/303, PGE's CONF Response to DR 12.

[46] This is displayed as a negative in the excel sheet and Figure 6 as revenues are an offset to total NVPC.

CONFIDENTIAL FIGURE 6. HISTORICAL SALES

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

ISSUE 4. TARIFFS

Q. Describe why tariffs are discussed in the Company's initial filing.

A. As of the Company's filing, President Trump intended to proceed with an executive order[47] that applied a 10 percent tariff on energy resources imported from Canada beginning April 2, 2025. The Company applied this 10 percent increase to the forward curves for AECO and Sumas as the Company anticipates Canadian sellers to pass on the entire tariff cost to US buyers.[48]

Q. How are they included in MONET?

A. Monthly Sumas and AECO gas prices are increased by tariffs on Canadian imports on the PC Input page in row 55. This can be turned on and off within the MONET model to assess the impact the tariffs have on total NVPC.

Q. As a result, what additional costs did PGE include in its NVPC filing?

A. Ten percent tariffs applied to Sumas and AECO gas increase forecasted NVPC by $16.8 million.[49]

Q. Is the Pacific Northwest uniquely affected by these tariffs?

A. In a way, yes. Currently, Canada is the only gas-producing region with firm transport capacity to serve Pacific Northwest markets and makes up as much as two-thirds of the gas consumed in the Northwest region and makes up an even larger share of PGE's firm pipeline rights.[50] In 2024 alone, imports from

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47 See Exec. Order 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025).
48 #_2026AUT-Canadian Tariffs.docx. See also PGE/100 Outama—Pederson/16.
49 As stated in PGE/100, Outama—Pederson/16.
50 Natural Gas Regional Infrastructure, Supply, and Demand (accessible at https://www.nwcouncil.org/2021powerplan_natural-gas-regional-infrastructure-supply-and-demand/). See also Imposing Duties to Address the Flow of Illicit Drugs Across our Northern Border (accessible at https://www.whitehouse.gov/presidential-actions/2025/02/imposing-duties-to-address-the-flow-of-illicit-drugs-across-our-national-border/).

Canada accounted for 89 percent of supply to the region and 185 percent of total consumption (with excess gas flowing into Northern California).[51] These imports come from Canada via Northwest Pipeline in Washington and GTN, which comes in from Idaho. Gas from the Rockies is sent via the Ruby Pipeline but this is at a much smaller scale due to Canadian competitiveness.[52] Generally, Canada is a net electricity exporter to the US.

Q. Could the Administration reverse its decision?

A. Yes, according to the Company, the Administration could also change the applicability of the proposed tariff to United States-Mexico-Canada Agreement (USMCA) compliant goods, as it has done so in the past.[53] At this time, there is a lot of uncertainty around the impacts of the tariffs on natural gas as well as imported electricity.

Q. Does Staff have any recommendation at this time?

A. At this time, it is unclear the extent that tariffs will impact prices paid by the Company. Staff is not recommending any adjustment for now and is waiting for more news regarding the tariffs and their impact before making any additional assessments.

Q. Does this conclude your testimony?

A. Yes.

---

51 Trump Tariffs Include 10% Carve-Out for Canadian Gas, Power, and Minerals (accessible at https://www.spglobal.com/commodity-insights/en/news-research/latest-news/natural-gas/020225-trump-tariffs-include-10-carve-out-for-canadian-gas-power-minerals). Also included in Staff/302.

52 Tariffs on Canadian Energy and Their Effects on Regional Markets (accessible at https://insight.factset.com/tariffs-on-canadian-energy-and-their-effects-on-regional-markets).

53 Staff/302, PGE's response to Staff DR 22 (pdf).

CASE: UE 452
WITNESS: JULIE DYCK

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 301

Witness Qualifications Statement

June 23, 2025

WITNESS QUALIFICATIONS STATEMENT

NAME: Julie Dyck

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Utility Analyst
Rates, Safety and Utility Performance Program

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

EDUCATION: I have a Bachelor of Science from Berea College in Political Science. I also hold a Masters of Integral Economic Development Policy specializing in the public sector and econometrics. I have completed rate school with NARUC, a data analytics course with Google, and am currently a NABE Frank Schott Scholar working towards becoming a Certified Business Economist.

EXPERIENCE: I was employed as a Junior Utility Analyst by the Oregon Public Utility Commission starting in June 2021 in the Telecommunications and Water division. I transitioned to the ERFA/RSUP Division in July of 2022 as a senior economist. Within this division, I currently perform a range of financial analysis duties related to natural gas and electric utilities, with a focus on Power Cost filings. In addition, I assist with Purchased Gas Adjustments, Annual Power Cost filings, and General Rate Cases. Rate case experience include: UE 435, UE 433, UG 435, UE 399, UE 416, and UG 461. I was previously employed as an adjunct professor of Econometrics at the Catholic University of America and as a Junior Analyst in the Office of Management and Budget (OMB) within the Executive Office of the President (EOP), where I worked as part of a team on higher education funding. Prior to EOP, I was an Economic Consultant for the U.S. Conference of Catholic Bishops.

CASE: UE 452
WITNESS: JULIE DYCK

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 302

Exhibits in Support
of Opening Testimony

June 23, 2025

Portland General Electric

Accurately identifying and quantifying electricity imports is essential to avoid over-counting or double counting emissions under the CCA. To aid in that effort, PGE encourages formal adoption of the lesser-of-analysis scenarios described in the Electric Power Entities (EPE) Under the Climate Commitment Act (CCA) White Paper ("White Paper") by administrative rule to provide clarity and certainty for the market as to the treatment of imported power.

Please see the attached comments.

PGE Comments on Linkage Rulemaking Electricity Considerations

December 18, 2024

Portland General Electric (PGE) appreciates the opportunity to comment on the imported electricity provisions of the Climate Commitment Act administrative rules. We appreciated the discussion of these issues with Ecology and other utilities in the 2024 Legislative Session on Senate Bill 6058.

PGE is a vertically integrated electric utility engaged in the generation, purchase, transmission, distribution, and retail sale of electricity in the State of Oregon. PGE serves over 900,000 retail customers with a service area population of approximately 2 million, comprising nearly half of the state's population. While PGE only serves retail customers in Oregon, we own and operate the Tucannon wind facility in Columbia County, Washington, and we transact power with Washington utilities and through the MIDC trading hub. PGE utilizes the MID-C wholesale interstate electric trading hub in Washington to trade power with Washington utilities and to serve our customers in Oregon.

Accurately identifying and quantifying electricity imports is essential to avoid over-counting or double counting emissions under the CCA. To aid in that effort, PGE encourages formal adoption of the lesser-of-analysis scenarios described in the Electric Power Entities (EPE) Under the Climate Commitment Act (CCA) White Paper ("White Paper") by administrative rule to provide clarity and certainty for the market as to the treatment of imported power.

It is especially important that Ecology ensures an entity such as PGE can demonstrate that electricity sourced from a 'composite source POR' was separately accounted for because the electricity supply either originated from a Washington resource or Washington Balancing Authority Area. To-date, PGE uses the lesser-of-analysis documented in the White Paper to show that electricity and any associated emissions sourced from a 'composite source POR' in a multistate BAA was separately accounted for. The example described in Appendix 1 of the whitepaper (see page 28) outlines PGE's situation, and the importance of the lesser-of analysis to avoid overstating emissions.

Please see below for our response to Department of Ecology's questions that are applicable to PGE:

1. *How should Ecology implement the term "common point"? Should "common point" include or refer to: a single Point of Receipt/Point of Delivery (POR/POD); any PORs/PODs within the same Balancing Authority Area (BAA) located entirely within WA; or something else?*

PGE response: PGE supports the definition proposed by Western Power Trading Forum (WPTF) in its comments submitted September 27, 2024. Specifically, WPTF proposed the definition: "Common Point" means, for purposes of identifying electricity wheeled through the state, PORs and PODs within the same BAA located entirely in Washington, Electricity exported from Washington must be matched to an electricity import that sinks to a POD in the same BAA to be considered electricity wheeled through the state on separate e-tags.

2. *How should Ecology implement the term "trading hub" specific to the MID-Columbia (MID-C) area? Should trading hub refer to: the MID-C adjacency only; a broader set of PORs/PODs associated with MID-C transactions. If so, how should these be defined; or something else?*

   PGE response: PGE recommends the formal adoption of lesser-of-analysis scenarios described in the Electric Power Entities (EPE) Under the Climate Commitment Act (CCA) White Paper as the means of implementing the term trading hub, which was intended to recognize hubbing arrangements at the Mid-C area. PGE agrees with WPTF's recommendation that Ecology formally adopt provisions to enable entities to use the lesser-of analysis to show that electricity and any associated emissions sourced from a 'composite source' POR in a multistate BAA was separately accounted because it was partially (or completely) supplied from a Washington resource or sourced from a Washington-only BAA.

3. *For unspecified imports initially sinking at a trading hub, should "wheel throughs" be limited to occurring into and out of the same BAA at the trading hub. (e.g. An Electric Power Entity (EPE) transacting at MID-C and sinking and sourcing from both BAA X and BAA Y, "wheel throughs" would have to be separately calculated for BAA X and BAA Y even if all source PORs/PODs are associated with the MID-C area).*

   PGE response: See PGE's answers to Items 1 and 2. PGE supports the definitions proposed by WPTF that would limit wheel-throughs to PORs/PODs within the same BAA. For entities such as PGE whose BAA is considered out of state, PGE recommends the formal adoption of the use of lesser-of-analysis to show that electricity and any associated emissions sourced from a 'composite source' POR in a multistate BAA was separately accounted because it was partially (or completely) supplied from a Washington resource or sourced from a Washingtononly BAA.

"Balancing Energy"

Ecology requests multistate BAAs and interested parties provide feedback on the following topics. This information will help Ecology determine if and how balancing energy may be separately accounted for in electricity reporting as enabled by SB 6058.

For balancing energy provided to in-state generators by a MJRP, a multistate BAA without retail load in WA, or a federal system:

- *Is balancing energy provided by the multistate BAA associated with "system energy"?*

- *Would it be appropriate to apply a system emission factor or an unspecified emission factor to any balancing energy provided by the multistate BAA?*

- *Is balancing energy provided by the multistate BAA generally associated with certain resources (e.g. hydro power or centralized electricity market purchases)?*
- *Is balancing energy provided by the multistate BAA fully accounted for by other aspects of EPE reporting?*

PGE response: PGE recommends against the use of an unspecified emission factor. PGE recommends Ecology allow for the use of (1) a system emission factor or (2) resource-specific emission factors if an entity can identify the resource(s) providing balancing services for the resource in question. For example, in PGE's circumstance, the Tucannon wind facility in southeastern Washington is pseudo-tied into the PGE Balancing Authority Area, and balancing energy is provided by PGE's resources providing regulation service to the PGE Balancing Authority Area. If PGE needed to identify the provision of balancing services for the Tucannon wind facility, PGE could identify the resources providing regulation service in each hour and therefore provide a set of resource-specific emission factors that is more detailed than a system emission factor.

April 23 2025

To: Julie Dyck
Oregon Public Utility Commission

From: Jaki Ferchland
Senior Manager, Pricing, Tariff, and Power Cost Recovery

Portland General Electric Company
UE 452
PGE Response to OPUC Data Request 003
Dated April 9, 2025

Request:

Please provide a narrative description of how the Company's gas and electricity official forward price curves are derived.

Response:

The Company develops electricity and natural gas forward price curves using a combination of data from various sources. Gas and power forward price curves are developed starting with price data delivered from term traders transacting in the open markets. The company also receives forward prices from various third-party data providers including brokers, and proprietary price publications. This third-party data is aggregated then compared against the forward prices provided by term trading to develop a separate final forward price curve data set. The final forward price curves are then adjusted to be within 5% of the third-party price data, ensuring prices are not off market. To reiterate, forward price curves from term trading are used as the primary source to develop the final forward price curves when information is provided. Forward price curves are reviewed daily by risk management. These final price curves are then automatically sent to the Company's system-of-record to be used as the official forward price curve.

2024 US electricity price growth continues moderation trend since 2022 spike

Tuesday, April 29, 2025 11:55 AM ET

A + A -

In 2024, the average retail price of electricity paid by ultimate customers in the US increased 0.9% on a nominal basis, reaching 13.44 cents per kilowatt-hour, compared to 13.32 cents/kWh in 2023. The incremental uptick continues the trend of price moderation that began in 2023, which saw a 3.7% increase, following a significant 12.1% surge in 2022. When adjusted for inflation, the real price in 2024 declined 1.6%, marking the first real price decline since 2020. The ultimate customer classification is an aggregate of the residential, commercial and industrial classes.

The Take

➤ In 2024, the average US electric price for ultimate customers rose 0.9% nominally, following a 3.7% increase in 2023 and a 12.1% jump in 2022.

➤ The electricity price trajectory in 2025 may continue to be moderate, assuming economic and geopolitical turbulence does not unduly impact energy costs. However, it is possible that 2025 and 2026 prices could rise more intensely than in recent years if US tariffs and potential retaliatory tariffs ultimately impact supply chains and impel higher inflation.

US electricity prices in 2025 may continue to track a moderate trajectory. However, in 2026 and beyond, prices may rise more steeply compared with 2023 and 2024, if significant fallout materializes from the imposition of US tariffs as well as from other potential unexpected geopolitical events. While strong natural gas production from US shale basins is anticipated to keep pace with growing LNG exports and support a continuation of moderate electrical prices, economic and geopolitical impacts may supersede.

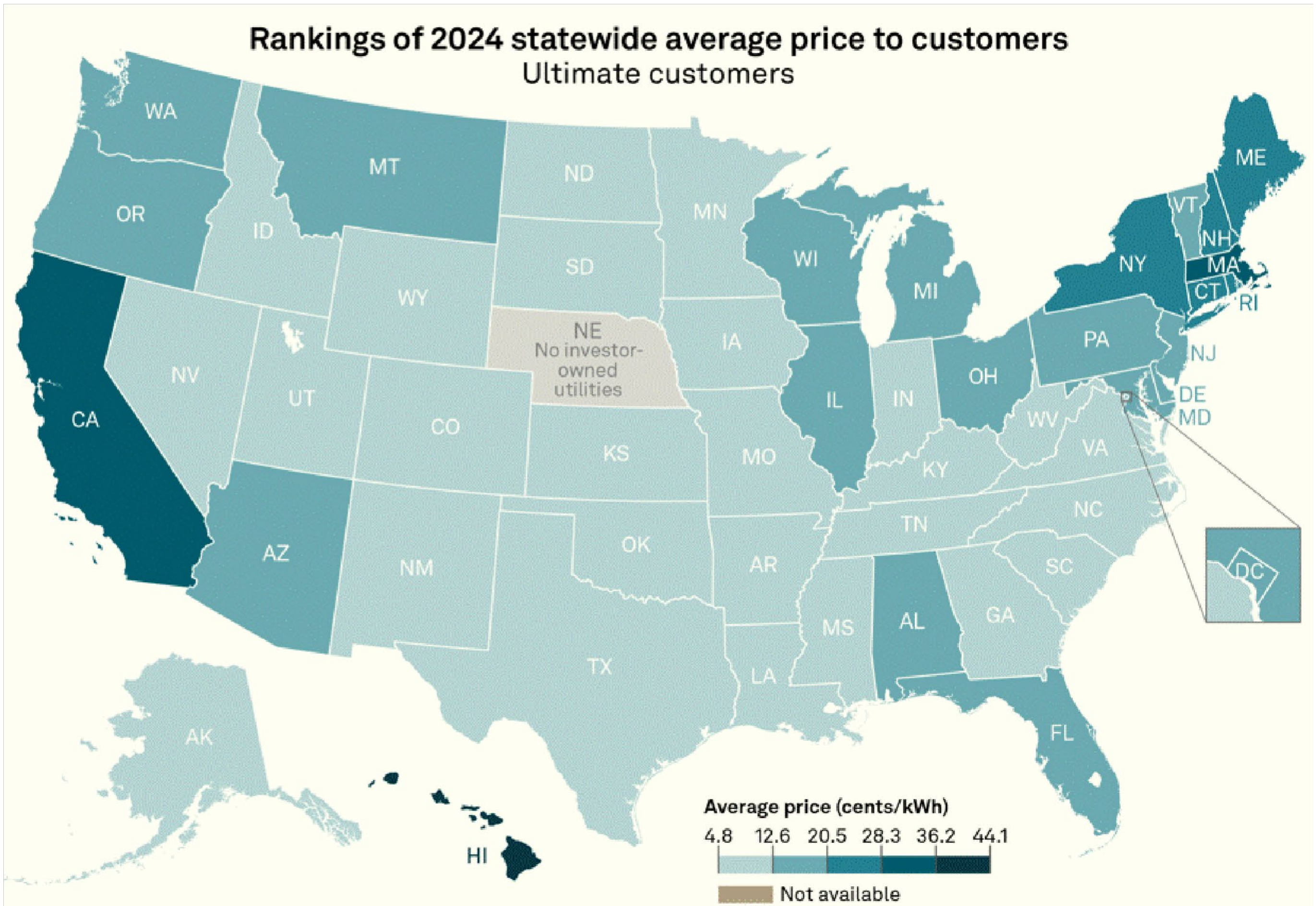
Regional infrastructure investments, particularly in the Northeast and West Coast, may lead to some regional above-average price increases due to grid resilience investments and decarbonization initiatives, while the Southeast and Mountain West are likely to maintain more stable pricing paths. Uncertainty in the US economy — due to the imposition of tariffs, counter-tariff actions by other countries and the ultimate response of the US Federal Reserve — could drive higher materials, energy and capital costs for utilities, eventually impacting retail power rates.

Price dynamics by customer class

The 2024 ultimate customer price showed a marked decrease, rising just 0.9% nominally, compared to 3.7% in the previous year and 12.1% in 2022. Residential customers experienced the largest nominal price increase in 2024 at 1.8%, with prices moving from 16.59 cents/kWh to 16.89 cents/kWh. Commercial customers saw a smaller increase of 0.3%, reaching 12.77 cents/kWh from 12.73 cents/kWh in 2023. Industrial customers experienced a price decrease of 0.4% in 2024, with prices falling to 8.28 cents/kWh.

Geographic and utility company price variations

Hawaii continues to exhibit the highest bundled electricity prices in the nation at 38.41 cents/kWh for ultimate customers, while Louisiana offered the lowest ultimate customer price at 8.41 cents/kWh. California remains the second most expensive state for electricity at 30.20 cents/kWh for the ultimate customer classification. Among utility holding companies, Hawaiian Electric Industries Inc., PG&E Corp. and Sempra Energy commanded the highest ultimate customer prices, whereas Otter Tail Corp., MDU Resources Group Inc. and OGE Energy Corp. had some of the lowest ultimate rates.



Data compiled April 17, 2025.
Refers to bundled power sold to retail electric customers of investor-owned utilities under rates subject to the oversight of state regulatory commissions.
Source: S&P Global Market Intelligence.

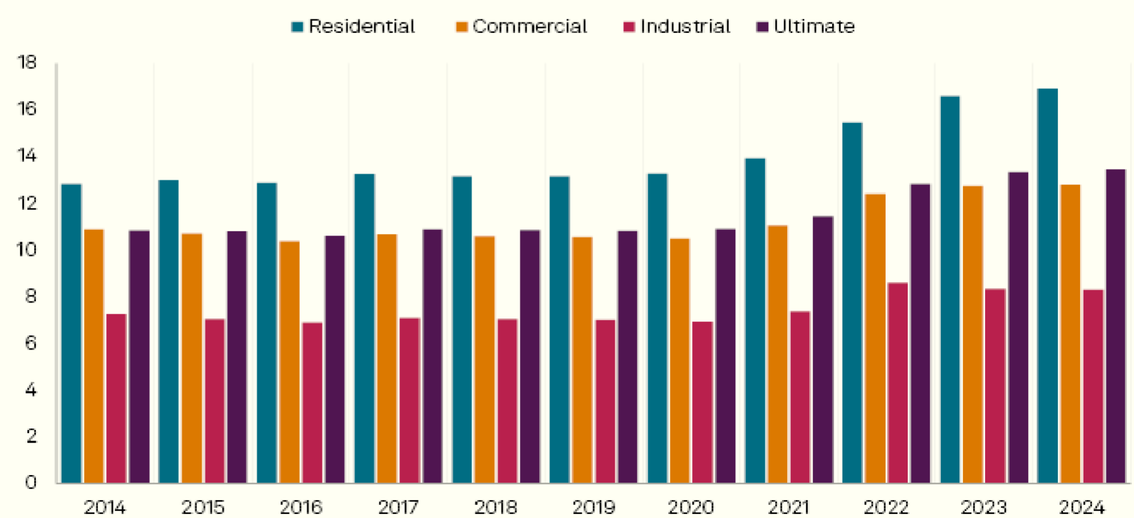
Regional utility price patterns

In the Western region, companies operating primarily in California, such as Pacific Gas & Electric, a subsidiary of PG&E Corp., and Southern California Edison, a subsidiary of Edison International, have some of the highest rates nationally, driven by multiple factors including extensive wildfire mitigation investments, ambitious renewable targets and higher transmission costs. Pacific Northwest utilities benefit from abundant hydroelectric resources, allowing for lower rates. In the Northeast, New England utilities maintain consistently high rates due to natural gas pipeline constraints, nuclear plant retirements and substantial grid modernization investments. Mid-Atlantic companies exhibit moderate to high retail rates, influenced by capacity market structures and aging infrastructure. In the Southeast, traditional vertically integrated utilities sustain relatively stable mid-range pricing, with Florida utilities generally having higher rates due to hurricane hardening investments and natural gas dependence. In the Midwest, states with significant coal and nuclear generation generally maintain lower-than-average prices despite recent upward pressures. Utilities in the Mountain/Central region maintain some of the nation's lowest rates due to abundant coal resources, low-cost hydroelectric power and lower infrastructure requirements.

Historical context and recent trends

The 2022 electricity price spike was the first time since 2006 that real prices grew more than 5% in a year. This unusual surge was driven primarily by sharp increases in natural gas prices, which propelled wholesale electricity costs markedly higher across markets. The moderation in electricity price increases during 2023 and 2024 can be attributed to stabilizing natural gas prices as production from US shale basins reached record levels. Despite natural gas contributing approximately 43% of US electricity generation, increased production has helped offset demand growth from LNG exports and industrial consumption.

US average retail price of electricity by customer type, 2014–24 (cents/kWh)



Data compiled April 17, 2025.

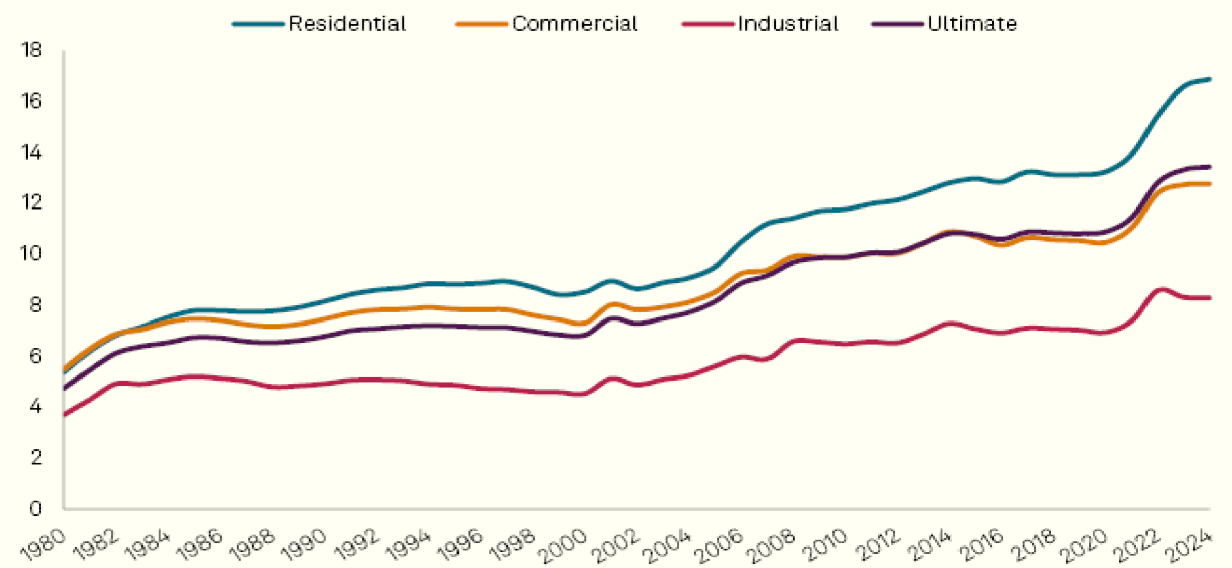
Ultimate customer represents an aggregate of residential, commercial and industrial customer classifications. The customers in these classifications have purchased electricity for their own consumption rather than for resale.

Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.

Long-term price trends

Over the period from 1978 to 2024, nominal ultimate customer prices increased 263.2%, with residential, commercial and industrial prices rising 291.8%, 192.9% and 195.6%, respectively. However, when adjusted for inflation, ultimate customer prices have decreased 12.4%, reflecting the long-term stabilizing effects of technological improvements and fuel source diversification. More recently, from 2014 to 2024, ultimate customer prices increased nominally 24.3%, with residential customers seeing the largest increase at 35.5%.
After inflation adjustment, ultimate prices declined 5.5% over this period, with only residential customers experiencing a real price increase of 3.0%.

US average retail price of electricity by customer type, 1980–2024 (cents/kWh)



Data compiled April 17, 2025.

Ultimate customer represents an aggregate of residential, commercial and industrial customer classifications. The customers in these classifications have purchased electricity for their own consumption rather than for resale.

Source: Regulatory Research Associates, a group within S&P Global Commodity Insights.

In an effort to align data presented in this report with data available in S&P Global Market Intelligence's online database, earlier historical data provided in previous reports may not match historical data in this report due to certain differences in presentation. In addition, the data within this report is largely derived from information obtained from the EIA. The error capture and update methodology utilized by the EIA is outside the control of S&P Global Market Intelligence. Accordingly, S&P Global Market Intelligence does not guarantee the accuracy, completeness or timeliness of any content provided herein.

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More...

April 23 2025

To: Julie Dyck
Oregon Public Utility Commission

From: Jaki Ferchland
Senior Manager, Pricing, Tariff, and Power Cost Recovery

Portland General Electric Company
UE 452
PGE Response to OPUC Data Request 007
Dated April 9, 2025

Request:

Describe how the company carries out wholesale power purchases and sales.

a. In addition, state what percent of purchases and what percentage of sales happen in each market,
b. How many MWh are typically sold in a given year and how much has happened so far in this AUT?

Response:

PGE objects to this request as vague, calling for speculation as to time period being referenced and requiring significant new analysis. Without waiving said objections, PGE replies as follows:

As part of its normal business operations, PGE purchases and sells power in the open market under short- and long-term contracts. Examples of short-term contracts would be purchases and sales conducted in a Day-Ahead or Real-Time trading horizons (e.g., delivery lengths measured in days and hours). Examples of long-term contracts would be forward contracting conducted under a Request for Proposal (e.g., delivery lengths measured in years). Physical purchases or sales may also occur for delivery beginning in 2026 (i.e., the Net Variable Power Cost forecast year).

a. See PGE’s Response to OPUC Data Request No. 012. OPUC Staff can derive percentages from the categories shared in PGE’s response.

b. PGE’s Response to OPUC Data Request No. 012 provides historical sales data.

April 23 2025

To: Julie Dyck
Oregon Public Utility Commission

From: Jaki Ferchland
Senior Manager, Pricing, Tariff, and Power Cost Recovery

Portland General Electric Company
UE 452
PGE Response to OPUC Data Request 011
Dated April 9, 2025

Request:

Please provide a narrative explanation of how PGE carries out wholesale sales, including details of:

a. Which timeframes are sales enacted in, including a definition of each timeframe referenced? Please specify which actuals correspond to which forecasted amounts.
b. The mechanism through which sales are enacted, e.g. through markets, counterparties, brokers, other?
c. What factors are taken into account when deciding to sell power?
d. How does owned transmission capacity, or transmission capacity available for sale, factor into the Company's decision to sell power?
e. What communication takes place between PGE's power sales team and the wider management group to inform power sales? Please describe the type and frequency of communications, reports, meetings, and any other types of communications.
f. What reference prices are taken into account when choosing to sell power? If this response differs according to the timeframe, please provide a separate response for each timeframe.
g. Describe the interplay between risk management and power sales and detail any conflicts between the two and how they are handled.

Response:

PGE object to this request as vague and overly broad. Notwithstanding its objection, PGE replies as follows.

a. As noted in PGE's Response to OPUC Data Request No. 007, PGE sells power in the open market under short- and long-term contracts. Please see Confidential Attachment 012-A for actuals and forecast data.

b. PGE completes wholesale sales through several methods. Examples include the following:
   1. PGE completes real time sales bilaterally (direct or through exchange), through CAISO hour-ahead bidding, and western Energy Imbalance Market (western EIM).

   2. PGE completes day ahead sales bilaterally (direct or through exchange), via brokers, or through CAISO day-ahead bidding.
   3. PGE completes forward sales in time periods prior to the start of cash trading (i.e., Day Ahead and Real Time) bilaterally (direct or through exchange) and via brokers.

b. PGE participates in the wholesale electricity marketplace to balance its supply of power to meet the needs of, and obtain reasonably priced power for, its retail customers, as well as manage risk, and administer its long-term wholesale contracts. PGE's engagement in the wholesale electricity marketplace depends upon numerous factors, including: 1) the relative price and availability of power, whether purchased, generated, or from storage facilities; 2) hydro, wind, and solar conditions; and 3) daily and seasonal retail demand. The Company also participates in the California Independent System Operator's (CAISO) western EIM, which allows for load balancing with other western EIM participants in fiveminute intervals.

c. Interconnected transmission systems in the western United States and Canada serve utilities with diverse load requirements and allow the Company to purchase and sell electricity, largely through bi-lateral agreements, within the region to serve retail demand.

d. See PGE's Response to OPUC Data Request No. 009. The procedures provide guidance on evaluating, aggregating, monitoring, and reporting exposures in market risk.

e. Reference prices will be the prevailing market prices for power in the trading time window (e.g., real time, day ahead, or forward markets). Prevailing market prices are influenced primarily by factors related to supply and demand. These factors generally include the adequacy of generating capacity, scheduled and unscheduled outages of generating facilities, hydroelectric and wind generation levels, prices and availability of fuel sources for generation, disruptions or constraints to transmission facilities, weather conditions, economic growth, and changes in technology.

f. See PGE's Response to OPUC Data Request No. 009. PGE's Energy Trading Risk Management Policy provides a framework for how PGE manages energy market risk and provides oversight of energy trading risk.

April 23 2025

To: Julie Dyck
Oregon Public Utility Commission

From: Jaki Ferchland
Senior Manager, Pricing, Tariff, and Power Cost Recovery

Portland General Electric Company
UE 452
PGE Response to OPUC Data Request 016
Dated April 9, 2025

Request:

Where does PGE source its natural gas supply from? Please include in your response the name(s) of the city gates and the gas volumes contracted.

Response:

PGE does not purchase at a city gate. PGE sources its natural gas supply from three regions and maintains firm transportation rights to the trading hubs associated with the regions:

1) Natural gas sourced from British Columbia/Western Alberta and delivered to a trading hub location commonly known as “Sumas Hub”;
2) Natural gas sourced from Alberta at a trading hub location commonly known as “AECO Hub”, and;
3) Natural gas sourced from the U.S. Rocky Mountain region (“Opal Hub” or “Rocky Mountain Pool”).

See PGE’s Minimum Filing Requirements, Volume 5 – Contracts / Gas Transportation for details on the firm transportation rights PGE holds to transport physical gas purchases to its power plants.

See also PGE testimony page 15, lines 1-11 and page 16, lines 1-14.

COAL, ELECTRIC POWER, NATURAL GAS

February 02, 2025

Trump tariffs include 10% carve-out for Canadian gas, power, minerals

By **Killian Staines, Daniel Weeks, Kip Keen, Zack Hale,** and **J Robinson**

HIGHLIGHTS

Tariffs on Canada, Mexico, China take effect Feb. 4
Could decrease US demand for Canadian hydropower
Metals tariffs to raise US manufacturing costs

US President Donald Trump on Feb. 1 followed through on a threat to hit the nation's three largest trading partners with steep tariffs. Energy imports from Canada — including oil, natural gas, electricity, coal, uranium, and critical minerals — were singled out, however, to be taxed at a lower rate of 10%.

Outside of the energy exclusions, Trump's executive orders imposed 25% across-the board tariffs on imports from Canada and Mexico and a 10% tariff on imports from China. No energy-related exemptions were identified for Mexico or China. The new tariffs will take effect on Feb. 4.

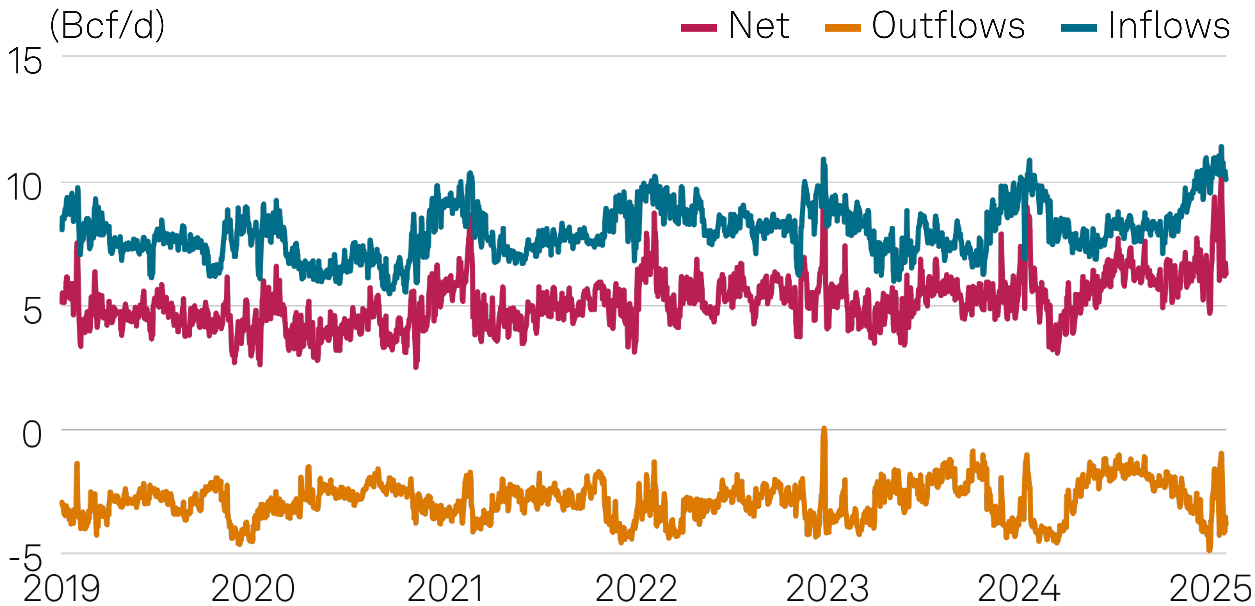
Canadian Prime Minister Justin Trudeau said Feb. 1 that the country would impose 25% tariffs on C$155 billion worth of US goods in response. Trudeau said the tariffs would go into effect on C$30 billion of US goods starting Feb. 4, and the tariffs applying to the other C$125 billion worth will go live in 21 days to allow Canadian companies to find alternative supply chains.

In a clause addressing potential retaliation against the US, Trump noted that he "may increase or expand in scope the duties" to ensure their efficacy.
Trump asserted that the tariffs are necessary to address crisis-level flows of undocumented immigrants and illegal drugs such as fentanyl into the US. Two different federal statutes authorize the US president to implement economic tariffs to address national emergencies. Executive orders for Mexico and China were not immediately available at press time.

Cross-border natural gas flows

The Pacific Northwest consistently imports gas from Western Canada, whereas the Northeast and Midwest tend to alternate between net imports and exports, depending on demand and pricing.
Imports from Canada accounted for 89% of supply to the Pacific Northwest in 2024, and 185% of total consumption, with most of the excess gas flowing to Northern California, S&P Global Commodity Insights data showed.

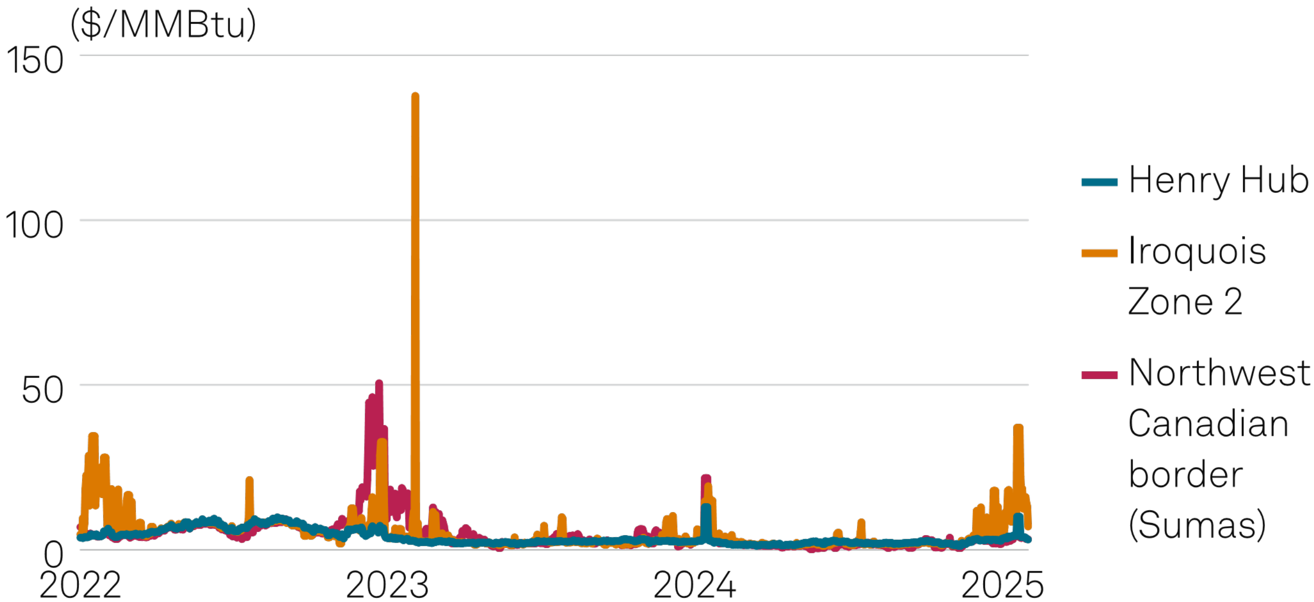
Canadian imports are also important for premium markets like New England's Algonquin city-gates and Iroquois Zone 2, which are prone to price spikes during winter because of limited pipeline connectivity as happened in January 2025 with prices regularly double-digits per MMBtu.



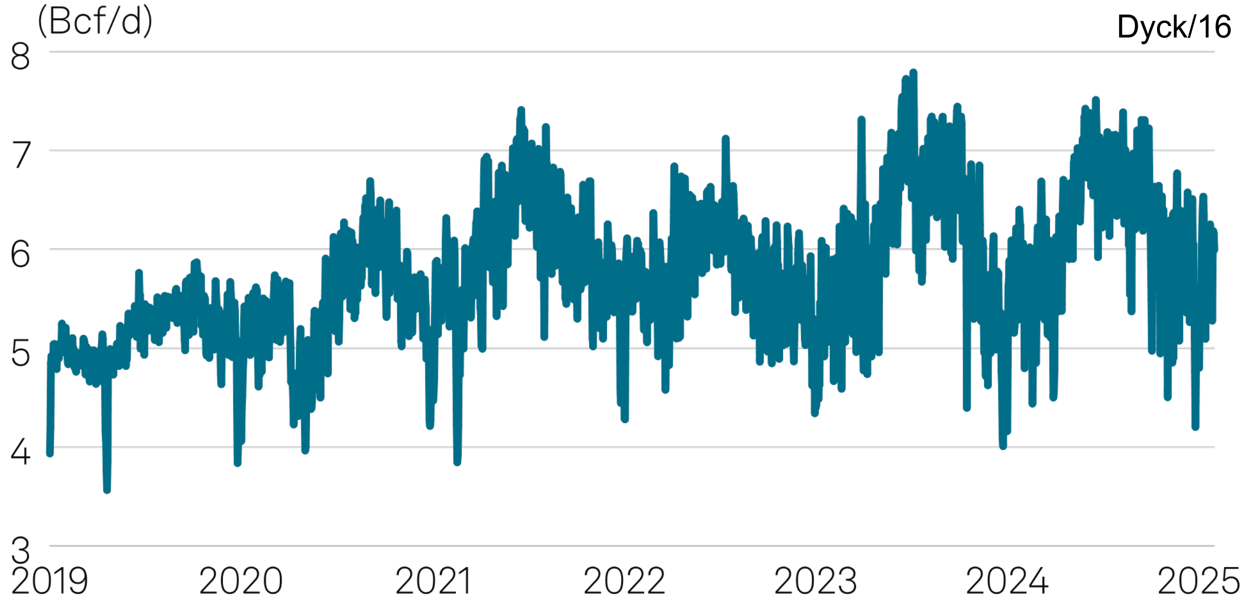
Source: S&P Global Commodity Insights

January 2025 was a bumper month for Canada-US gas flows. Net flows averaged about 7.6 Bcf/d during the month, the highest monthly net export level since 2008, Commodity Insights data showed early Jan. 31. This accounted for about 7% of total Lower-48 supply, the data showed.
Exceptionally cold weather drove strong heating demand and took some production offline in the United States during January. Meanwhile, Canadian production has remained strong this winter despite record storage inventories, which have generally been pressuring Canadian gas prices.

p **p**



Source: S&P Global Commodity Insights



Source: S&P Global Commodity Insights

And the anticipation of tariffs may have already been having an impact on the Canadian gas market. "The Canadian dollar has depreciated this winter, impacted by various economic challenges facing Canada, including the potential Trump tariffs," Ian Archer, a natural gas analyst at Commodity Insights wrote Jan 29. At the Western Canadian AECO hub, "the January 2025 average spot price ... is nearly identical to that of January 2019, while the equivalent U.S. price is 10 cents lower when converted to American currency."

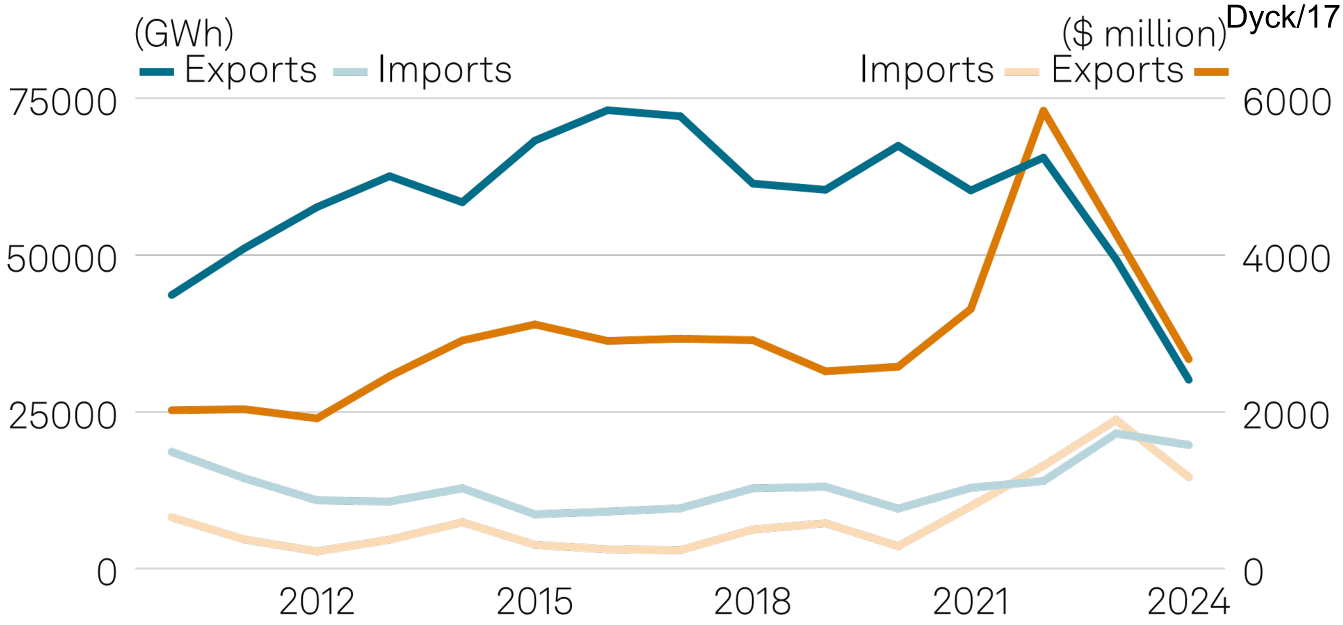
Gas flows with Mexico are less complicated in that the US consistently exports. USMexico flows averaged 6.4 Bcf/d in 2024, accounting for 73% of total consumption in Mexico, Commodity Insights data showed. Even if Mexico opts for retaliatory tariffs, it would have limited alternative supply options to US imports.

US demand for Canadian power imports

Canada is generally a net electricity exporter to the US — except for a period in early 2024 when severe drought impacted hydropower generation. Hydropower makes up most of Canada's electricity generation and power exports to the US, said Hilary Bao, senior analyst at Commodity Insights, in a report Jan. 28.

"In a favorable hydro year like 2022, the US imported a net total of 51.6 TWh of electricity from Canada, a bit more than 1% of total US demand," Bao said. Hydropower should rebound in 2025, she said.

The 25% tariff could decrease demand for the Canadian power, Bao said. The total value of Canadian electricity exported in 2024 was about CAD$2.7 billion ($1.9 billion), or 30 TWh, according to the Canada Energy Regulator. The country imported about 20 TWh valued about CAD$1.2 billion.



Source: Canada Energy Regulator

New York state saw the most power imported from Canada in 2024 at 7.7 TWh, according to data from the regulator. The New York Independent System Operator said it is in "close and regular contact" with Quebec and Ontario to ensure a reliable grid and stable electricity flows.

ISO New England said the integration of the US and Canadian power systems "benefits residents and businesses in both countries." ISO-NE states are some of the largest Canadian power importers, with Vermont importing 3.9 TWh and Maine importing 2.3 TWh in 2024.

Leading up to the tariffs, the premiers of two Canadian power-exporting provinces, Doug Ford of Ontario and David Eby of British Columbia, threatened to cut exports to the US if the tariffs were imposed. These provinces, alongside Quebec deliver most of the electricity exported to the US, according to the Energy Information Administration have said.

The three countries are heavyweight suppliers of metals and minerals to the US and accounted for 41% of the total value of US metal and mineral imports in 2023, according to a Commodity Insights analysis of data from the US International Trade Commission.

US imports included unwrought aluminum, base metals, steel and precious metals. In cases like aluminum and processed lithium, US buyers may have trouble finding alternative sources not covered by tariffs. By value, Canada accounted for more than half of US imports of aluminum products in the past year and a half, according to US Commerce Department data.

"Today, much of that metal comes from North American trading partners, especially Canada," Matt Meenan, vice president of external affairs at The Aluminum Association, said in a Jan. 31 email. "The US industry sources around two thirds of the primary aluminum it uses every year from Canada, since all US-based smelters, even running at full capacity, cannot produce nearly enough metal to meet demand."

Meanwhile, China accounted for the majority of global refined lithium supply in 2023, according to the International Energy Agency.

These potential trade soft spots have not gone unnoticed. Canada flagged US dependence on Canadian raw materials in the run up to Trump's tariffs, as it prepared countermeasures, which Prime Minister Trudeau has yet to reveal.

"If they don't get them from Canada, they'll get them from China," said Trudeau, whose government has said everything is on the table in terms of countermeasures. "And if they can't get them from Canada or China, they don't get them from anywhere."

On the eve of possible tariffs, the Mining Association of Canada warned that US consumers would pay a higher price. Setting aside US imports of Canadian oil products, Pierre Gratton, president and CEO of the industry group, said the US runs a trade surplus in other areas with Canada, including manufacturing.

"Canada's resource sector enables that manufacturing surplus," Gratton said in a Jan. 31 interview. "We're the ones that actually make their manufacturing sector strong and competitive because we're a reliable, secure source of minerals and metals. So we need to impress that upon them."

Canada was the top US source of metals and mineral imports in 2023, valued at $46.97 billion. China and Mexico followed, with US imports valued at $28.32 billion and US$28.18 billion, respectively, according to ITC data.

Still, the US steel industry has expressed support for tariffs, including on Canada, saying they would offset "market-distorting behaviors." The Aluminum Association has said the US should exempt Canadian aluminum but take measures to tackle "unfair" global trade in aluminum.

April 23 2025

To: Julie Dyck
Oregon Public Utility Commission

From: Jaki Ferchland
Senior Manager, Pricing, Tariff, and Power Cost Recovery

Portland General Electric Company
UE 452
PGE Response to OPUC Data Request 022
Dated April 9, 2025

Request:

See the following articles: Trump's tariffs already have a major carve-out. Oil and gas: Russell | Reuters and Fact Sheet: President Donald J. Trump Declares National Emergency to Increase our Competitive Edge, Protect our Sovereignty, and Strengthen our National and Economic Security – The White House.

a. How has PGE interpreted any carveouts for energy commodities?
b. Does PGE plan to revise its request?
c. What would PGE's revised request be if the tariffs did not apply to natural gas?
d. Provide updated copies of any natural gas workpapers that have changed as a result of these exclusions to the tariffs.

Response:

a. PGE's natural gas purchases are considered United States-Mexico-Canada Agreement (USMCA) compliant goods, and at the time of this response, the proposed tariff, and its associated 90-day moratorium, does not apply. The administration could reverse their decision on applicability of the proposed tariff to USMCA compliant goods in the future, as they have done in the past, at which point PGE's natural gas purchases would fall under the proposed tariff.

b. Not immediately. The annual update tariff schedule allows for price curve updates at identified milestones in the proceeding. PGE intends to make its final AUT tariff update in November 2025 during the last update of price curves in this proceeding.

c. The request would reduce from $16.8 million to zero. PGE has only modeled a direct tariff impact on natural gas purchases.

d. Not applicable. There are no new workpapers.

CASE: UE 452
WITNESS: JULIE DYCK

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 303

Portland General Electric's (PGE's) Redacted Responses to Staff Data Requests

June 23, 2025

April 23 2025

To: Julie Dyck
Oregon Public Utility Commission

From: Jaki Ferchland
Senior Manager, Pricing, Tariff, and Power Cost Recovery

Portland General Electric Company
UE 452
PGE's CONFIDENTIAL Response to OPUC Data Request
004 Dated April 9, 2025

Request:

Please list all sources the Company uses for the pricing of its natural gas and electricity.

Response:

PGE objects to this request on the basis that it is vague, overly broad, and unduly burdensome. Without waiving said objections, PGE responds as follows:

The Company uses price data for the purpose of developing forward power and natural gas prices from multiple sources including but not limited to the following:

[BEGIN CONFIDENTIAL] [redacted] **[END CONFIDENTIAL]**

PGE's Confidential Response to Staff Data Request 12 Attachment A is available in electronic spreadsheet format only.

CASE: UE 452
WITNESS: BONNIE GARIETY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 400

Opening Testimony

June 23, 2025

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

A. My name is Bonnie Gariety. I am a senior analyst employed in the Utility Strategy and Planning Energy Section of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My Witness Qualifications Statement is found in Exhibit Staff/401.

Q. What is the purpose of your testimony?

A. To respond to PGE's Opening Testimony discussing the estimated increase in net variable power cost (NVPC) that PGE asserts is primarily driven by Bonneville Power Administration (Bonneville or BPA) transmission rate increases.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared the following exhibits:

- Staff Exhibit 401 – Witness Qualifications Statement
- Staff Exhibit 402 – NewsData article about Bonneville Rate Increase
- Staff Exhibit 403 – Bonneville Evolving Grid Project Summaries and Maps
- Staff Exhibit 404 – Oregon Public Broadcast article about Bonneville Transmission Expansion projects
- Staff Exhibit 405 – PGE Non-Confidential Data Response 041
- Staff Exhibit 406 – PGE Non-Confidential Data Response 072

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

A. My testimony is organized as follows:

Issue 1. Long-Term Point to Point and Scheduling, Control and Dispatch 2
Issue 2. Real Power Losses Capacity Charge 6

ISSUE 1. LONG-TERM POINT TO POINT AND SCHEDULING, CONTROL AND DISPATCH

Q. Why do Bonneville Power Administration (Bonneville or BPA) rates matter in PGE's NVPC?

A. Because PGE transfers (or wheels) power over Bonneville's transmission lines to get power from off-system generating resources to load.

Q. What did PGE propose for its 2025 NVPC?

A. PGE predicts an increase over the 2025 NVPC is $50.6 million (1.6 percent increase to customers) of which $25 million is attributable to Bonneville rate increases from the BP-26 rate case.

Q. What is driving the increase in Bonneville rates?

A. PGE said the Bonneville rate increase is driven by a shift in capital funding strategy to support Bonneville's Evolving Grid (EG) projects, a new control center, and various other factors related to Bonneville's investments.[1]

Q. Can you explain Bonneville's Evolving Grid initiative?

A. Bonneville's EG initiative was created by Bonneville to address the regional objectives toward electrification, a shift toward renewable power, and the rise of data centers that use a massive amount of electricity. The agency has proposed two sets of transmission expansion projects (EG 1 and 2) to meet its customers' needs for transmission service.[2] There are about 23 proposed EG grid transmission expansion projects costing about $5 billion.[3]

[1] PGE/100, Outama-Pedersen/10-13.
[2] Staff/403, Gariety/1-7.
[3] Staff/404, Gariety 1-2.

Q. What are the Bonneville rate increases discussed by PGE?

A. PGE has described three substantial rate increases in Bonneville's BP-26 rate case proceeding affecting PGE (and PacifiCorp, Avista, Puget Sound Energy and Idaho Power.) There is a 22.9 percent (~$20 million) rate increase for long-term point to point (PTP), a 30 percent (~$4 million) rate increase for long-term scheduling, control and dispatch (SCD), and a 130 percent rate increase in real power losses capacity charge (RPL).[4]

Q. What factors does Bonneville say caused the rate increase?

A. Bonneville reports, "[t]he proposed rate increases [come] from a combination of inflationary pressures along with greater investments in maintaining and upgrading our power, transmission and other infrastructure. These investments are critically needed to position Bonneville to meet the growing energy needs of the Pacific Northwest region."[5]

Q. Are the Bonneville rate increases modeling changes appropriate?

A. In part. The rate increases for PTP and SCD are because those rates currently exist in the MONET model. According to PGE, it would be necessary to update the MONET model to include the RPL capacity rate. PGE asserts that it has not done so in this Annual Update Tariff (AUT).

Q. Are the Bonneville rate increases published in BP-26 rate Schedule included in PGE's Monet model?

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[4] Staff/406, Gariety, PGE's response to Staff Data Request No. 072.
[5] Staff/402, Gariety/1.

A. The PTP rates (actual and as filed) are included. The SCD (actual and as filed) are also included. Any impact to NVPC from the RPL capacity charge is not evident. The RPL charge is discussed further in Issue 2 below.

Q. Are the Bonneville rate increases beyond the company's control?

A. Not entirely. PGE and other investor-owned utilities can and do participate in Bonneville's rate-case proceedings and can have an impact on Bonneville rates.

Q. Was PGE's strategy in response to Bonneville's proposed rate increase appropriate?

A. Yes. PGE responded to the proposed rate increase by meeting weekly with other impacted investor-owned utilities (joint utilities) to align on the BP-26 approach. The joint utilities worked together to submit a proposal within the BP-26 case advocating to reduce Bonneville's proposed increase to keep costs as low as possible for customers while ensuring reliable service.

Q. Should PGE continue to seek low-cost, low-risk strategies to keep prices as low as possible?

A. Yes. Given the region's reliance on the Bonneville transmission system to deliver energy to load, the constrained transmission landscape in the Pacific Northwest and the constrained flow gates in PGE's territory such as the South of Allston and Cross-Cascades South paths, PGE must consistently work to achieve least cost and least risk solutions in transmission upgrades and resource acquisitions in its Integrated Resource Plan and not shift unnecessary costs to customers through the net variable power cost mechanism.

Q. Please outline the remaining process for Bonneville's BP-26 Rate Case?

A. The Federal Register Notice announcing the commencement of Bonneville's BP-26 rate case was published on November 13, 2024. Bonneville reached an all-party settlement in the Transmission Rate Case. Once Bonneville issues its Final Order, expected on July 24, 2025, it goes to the Federal Energy Regulatory Commission (FERC) for review. Per the Northwest Power Act FERC review is limited. If approved by FERC, new Bonneville rates go into effect on October 1, 2025, for a three-year period from October 1, 2025, through September 30, 2028.

Q. Has PGE applied Bonneville's rate increases appropriately in MONET model?

A. Staff believes the Bonneville PTP and SCD rate increases are applied appropriately in the MONET model. PGE states that the increase in the RPL capacity charge is not included in the model, but Staff cannot verify this. See Issue 2 below.

ISSUE 2. REAL POWER LOSSES CAPACITY CHARGE

Q. How does PGE describe the real power losses capacity rate?

A. According to PGE's testimony, Bonneville's Firm Power and Surplus Products and Services Real Power Losses (RPL) Capacity Charge is for procuring energy to make up for line losses incurred when PGE uses Bonneville's transmission lines to deliver power to PGE's customers.

Q. What is Staff's concern with the rate increase related to the RPL capacity charge?

A. In PGE's testimony, of the three proposed Bonneville monthly transmission bill increases, the RPL capacity charge had the largest increase (130%)[6] yet PGE is not transparent about how it is seeking recovery of those costs.

Q. Is Bonneville's BP-26 rate increase for the RPL capacity rate applied in the MONET model?

A. It's unclear. PGE's initial filing suggests the Bonneville BP-26 rate increase for RPL capacity rate is applied in the MONET model because it is discussed in the "MONET Updates and Modeling Changes" section of PGE's testimony.[7] As noted above, the RPL capacity rate was not transparent in the model. When Staff sought clarification in discovery, PGE responded by noting a line in testimony "may have been misleading."[8] The Company further stated, "[t]he capacity rate for Bonneville's real power losses is not an input in the MONET model given including the capacity rate in MONET would have constituted an

[6] PGE/100, Outama-Pedersen/11.
[7] PGE/100, Outama – Pederson/11, lines 18-21.
[8] Staff/405, Gariety/1, PGE's Response to Staff Data Request No. 041.

enhancement and thus was not implemented. As a result, PGE's NVPC forecast does not reflect this real power losses capacity rate. If it were included, the price increase to customers would be higher than $24.6 million."[9]

Q. When can the RPL capacity charge rate increase be included in the MONET model?

A. As PGE noted in discovery, PGE is only allowed to include modeling enhancements in the Annual Update Tariff (AUT) if the changes are filed no later than February, which did not occur.[10]

Q. Do you agree that the Bonneville RPL capacity charge is not included in the MONET model?

A. Not necessarily. The RPL capacity charge rate increase may not be applied transparently as an input the MONET model in a similar fashion to the other two Bonneville rates. Without more information on PGE's accounting for RPL capacity charges assessed by BPA, Staff cannot verify that it is not accounted for in PGE's NVPC forecast.

Q. How does PGE treat Bonneville transmission line losses in MONET?

A. PGE states, "[l]ine losses for transmission delivered via Bonneville transmission lines, which are a significant portion of PGE's line losses, are settled physically in MONET. This occurs in two steps: 1. The MONET team

[9] Id.
[10] According to PGE's Schedule 125, "Should the Company propose modeling changes outside of a general rate case to be effective on January 1st of the following calendar year, the Company will file estimates of the proposed modeling changes and all associated minimum filing requirements no later than February 15 of the calendar year prior to the rate effective date. Any estimates for modeling changes proposed in a general rate case year shall be filed at the earlier of either the filing of GRC opening testimony or by April 1st prior to the rate effective date."

grosses up the load forecast entered into the model to account for these anticipated losses. 2. The model then simulates market purchases for the lost MWhs during transmission."[11]

Q. What load forecast was included in the MONET model?

A. In its initial filing, PGE testified it used the 2026 retail load forecast consistent with the September 2024 forecast vintage used for the final 2025 Test Year forecast in Docket No. UE 435.

Q. What is the RPL Capacity Charge?

A. It is Staff's understanding that the charge is assessed in connection with in-kind repayment of power provided by BPA to make up line losses. In BPA's Notice of FY 2024-2025 proposed power and transmission rate adjustments, BPA stated it was "propos[ing] two new charges associated with real power loss returns. First, Bonneville is proposing a charge to settle loss imbalances associated with in-kind loss returns. In addition, the Invalid Loss Return penalty charge is proposed to replace the Financial for Inaccuracy penalty charge in the current rate schedules and incent accurate and timely return of in-kind loss return obligations."[12]

Q. What does Staff ask PGE to provide to resolve whether the Bonneville RPL capacity rate was applied in MONET model or the load forecast?

A. Staff requests the following:

[11] Staff/405, Gariety/1, PGE's Response to Staff Data Request No. 041.
[12] BP-12 Notice of FY 2024-2025 proposed power and transmission rate adjustments at 20.

- Documentation that verifies Bonneville's increase in the RPL capacity charge is not incorporated into the AUT 2025 Test Year forecast, including confirmation the Bonneville RPL rate increase is not accounted for in the grossed-up load methodology used to settle line losses.
- If the Bonneville RPL capacity charge is incorporated into the forecast please provide information on the financial impact to customers in dollars.
- Please explain if the Bonneville RPL capacity charge has been included in the MONET model in previous AUT or general rate case filings.
- Please explain if the Bonneville RPL capacity charge been included in the MONET model previously and removed to include in the load forecast?
- Will Bonneville's BP-26 RPL capacity charge be applied as a MONET model enhancement or change in the Company's next AUT or general rate case filings? How will the model enhancement or change appear in the MONET model?

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 452
WITNESS: BONNIE GARIETY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 401

Witness Qualifications Statement

June 23, 2025

WITNESS QUALIFICATIONS STATEMENT

Name:	
Employer:	Bonnie Gariety
Title:	Public Utility Commission of Oregon
Address:	Senior Analyst Utility Strategy and Planning
Education:	201 High Street SE Ste 100 Salem, OR 97301-3612
Experience:	Master of Science in Economics, University of Wyoming

I have 20 years of experience in the utility industry. I have been employed at the Oregon Public Utility Commission since February 2025. My responsibilities include working on various dockets such as LC 80 PGE Integrated Resource and Clean Energy Plan, UM 2371 PGE Request for Proposal, and DR 58 Declaratory Ruling for PacifiCorp Small-Scale Renewables.

My prior work experience includes about ten years at Bonneville Power Administration in the Transmission Planning organization where I prepared the annual Transmission Plan. I also developed the proof on concept for the online public-facing interactive generation and line-load interconnection map.

Prior to Bonneville, I was employed with Portland General Electric and was an expert witness in marginal cost pricing in Docket Nos. UE 283 and UE 262. I also participated in several rate cases and prepared tariff filings.

I was a labor economist for the Oregon Employment Department where I estimated nonfarm payroll employment data (a.k.a. monthly jobs data) for the Portland Metropolitan area and its counties.

CASE: UE 452
WITNESS: BONNIE GARIETY

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 402

NewsData Article about Bonneville Rate Increase

June 23, 2025

SUPPLY & DEMAND

BPA Proposes Double-Digit Increases for Both Power and Transmission

by Steve Ernst

The Bonneville Power Administration's Tier 1 power rates would increase by 10.8 percent and transmission rates would jump by an average of 24 percent, under an initial rate proposal for fiscal years 2026 to 2028, the federal power marketing agency announced on Dec. 9.

The rate case proposal comes almost a month after the agency formally announced plans to adjust its transmission tariff to include a new Generator Interconnection Withdrawal Charge.

The proposal would subject power developers to a charge of between $5 million and $10 million if an interconnection request is withdrawn or deemed withdrawn after executing a Phase 2 Cluster Study Agreement. The charges increase, depending on how far into the cluster study process the project is withdrawn, according to the BP-26 Partial Rates Settlement Agreement.

Federal Register Notices for both the BP-26 and TC-26 were published on November 13 and the initial proposals were released November 22.

"We worked with our customers and other regional stakeholders to develop a plan to meet their increasing load and resource requirement needs, while also meeting our other statutory obligations," Joel Cook, chief operating officer for BPA, said in a prepared statement. "The proposed rate increases [come] from a combination of inflationary pressure along with greater investments in maintaining and upgrading our power, transmission, and other infrastructure. These investments are critically needed to position Bonneville to meet the growing energy needs of the Pacific Northwest region."

The proposed power and transmission rate increases come at a time when many Northwest consumer-owned utilities are facing increased rate pressure from acquiring new resources as well as upgrading and modernizing existing systems and infrastructure.

Scott Simms, executive director of the Public Power Council, told Clearing Up that the upcoming rate case will be about "balancing competing priorities."

"Given that on one side of the scale are substantial proposed power and transmission rate increases, and the other side is the need to continue to invest in BPA and its assets for the long term," he said. "PPC's approach will be to scour every opportunity for mitigating strategies that can provide some rate relief while ensuring BPA can deliver on its mission. It will likely be a difficult and contested rate case, but this isn't PPC's first rate-case rodeo and we and our members are saddled up and ready to go."

Northwest Requirements Utilities said its top priority is working with BPA to keep Tier 1 power rates affordable. NRU, which includes 57 member utilities in seven states, said it

U.S. Department of Energy/Flickr
Bonneville Power Administration transmission towers and lines with Mount Hood in the background.

understands the drivers leading to the proposed rate increases, but has serious concerns about the impacts on its members.

NRU will be taking a careful look at Bonneville's initial proposal, Emily Traetow, NRU's senior rates and policy director, said in an email to Clearing Up.

"Some of Bonneville's reasons driving the rate increases are valid. For example, we support needed investment in both the Power and Transmission systems," she said. "However, we believe that aspects of Bonneville's proposal would drive up costs unnecessarily, and we will be submitting testimony seeking to minimize rate increases where possible. Bonneville can and should make some changes to the initial proposal to bring down the rate increase, especially with respect to Transmission revenue financing," she added.

Spencer Gray, executive director of the Northwest and Intermountain Power Producers Coalition, said his group supports BPA investing in transmission and calls it a "positive for the region."

But NIPPC has issues with how BPA plans to finance those transmission investments, specifically the agency's use of revenue financing as opposed to the historic practice of using debt to financing.

"Using cash from customers is the most expensive way to finance transmission," he said. "Debt financing helps spreads costs out over generations who also benefit from those projects."

Gray said NIPPC also has issues with how Bonneville implements its Transmission reserves distribution clause, which is supposed to return overcollected transmission revenue back to customers.

"We are at the point where we think it should be renamed revenue non-distribution clause because on the transmission

CASE: UE 452
WITNESS: BONNIE GARIETY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 403

Bonneville Evolving Grid Project Summaries and Maps

June 23, 2025

Evolving Grid Project (EGP) 1.0 Summaries

EGP 1.0 consists of 10 proposed projects at a preliminary projected cost of $2 billion to support the region's electrification and clean energy goals.

Rock Creek-John Day 500 kV Line Upgrade

This project is an upgrade of the existing Rock Creek – John Day #1 500-kV line. BPA would rebuild 14 miles of line between the Rock Creek Substation (Goldendale, WA) and John Day Substation (Rufus, OR), including a Columbia River crossing.

This project will create additional capacity to support regional load growth, reliability needs and commercial requests for long-term transmission at a preliminary estimated direct cost of $37 million.

Estimated completion: Early 2030 (updated)

Big Eddy-Chemawa 230/500 kV Line Upgrade

This project is a rebuild of portions of the existing Big Eddy-Chemawa #1 230 kV line to 500 kV. BPA proposes to rebuild and re-terminate 91 miles of line between BPA's Big Eddy Substation (The Dalles, OR), Ostrander Substation (Oregon City, OR) and Pearl Substation (Wilsonville, OR).

This project will create additional capacity to support regional load growth, reliability needs and commercial requests for long-term transmission at a preliminary estimated direct cost of $670 million.

Estimated completion: 2032

Cross Cascades North Upgrades

This series of upgrades consists of three projects designed to reinforce the Cross Cascades North path on the FCRTS.

- Schultz-Raver 500 kV Line Upgrade: BPA proposes upgrading the existing Schultz-Raver #3 and Schultz-Raver #4 500-kV lines to a higher rated capacity. BPA would reconductor the 77 miles of line between BPA's Schultz Substation (Ellensburg, WA) and Raver Substation (Ravensdale, WA).
- Paul 500 kV Substation Upgrade: BPA proposes adding a new capacitor at Paul Substation (Centralia, WA).
- Olympia 230 kV Substation Upgrade: BPA proposes adding a new Static VAR Compensator at Olympia Substation (Olympia, WA).

This project will create additional capacity to support regional load growth, reliability needs and commercial requests for long-term transmission at a preliminary estimated direct cost of $400 million.

Estimated completion: 2031 (updated)

Ross-Rivergate 230 kV Line Upgrade

This project is a proposed upgrade of the existing Ross-Rivergate #1 230 kV line. The work would consist of replacing conductor on 7.5 miles of line between BPA's Ross Substation (Vancouver, WA) and PGE's Rivergate Substation (Portland, OR), including a Columbia River crossing.

This project will create additional capacity to support regional load growth, reliability needs and commercial requests for long-term transmission at a preliminary estimated direct cost of $50 million.

Estimated completion: 2029 (updated)

Chehalis-Covington 230 kV Line Upgrade

This project is a proposed upgrade of a portion of the existing Chehalis-Covington #1 230-kV line. The work would consist of replacing conductor on 35 miles of line between BPA's Chehalis Substation (Chehalis, WA) and Cowlitz Tap (Frederickson, WA).

This project will create additional capacity to support regional load growth, reliability needs and commercial requests for long-term transmission at a preliminary estimated direct cost of $95 million.

Estimated completion: 2028

Portland Area Upgrades

Keeler-Horizon 230 kV Line #2 - Completed (energized 2024)

Terminating PGE's new Keeler-Horizon #2 line at BPA's Keeler Substation (Hillsboro, OR) and a new 500/230-kV transformer would also be added at Keeler Substation.

Pearl-Sherwood-McLoughlin 230 kV Line Upgrade

Reconfiguring and re-terminating the Pearl-Sherwood-McLoughlin line at BPA's Pearl Substation (Wilsonville, OR).

Estimated completion: Summer 2026

Keeler 230/500 kV Transformer Addition

A new 500/230-kV transformer would also be added at Keeler Substation (Hillsboro, OR).

Estimated completion: 2029

In total, these projects will create additional capacity to support regional load growth, reliability needs and commercial requests for long-term transmission at a preliminary estimated direct cost of $150 million.

Bonanza 230/500 kV Substation

This facility would be a new hub substation in Central Oregon near Prineville, OR. The new 115/230/500 kV Bonanza Substation would be built near BPA's existing Ponderosa Substation.

This project will create additional capacity to support new resource development and access to non-federal resources at a preliminary estimated direct cost of $300 million.

Estimated completion: 2028 (updated)

La Pine-Bonanza 230 kV Line

This project is a proposed new 53-mile 230-kV transmission line in Central Oregon between BPA's La Pine Substation (La Pine, OR) and proposed Bonanza Substation (Prineville, OR).

This project will create additional capacity to support regional load growth, reliability needs and commercial requests for long-term transmission at a preliminary estimated direct cost of $150 million.

Estimated completion: Late 2029

Six Mile Canyon 230/500 kV Substation

This is a proposed new 230/500-kV hub substation called Six Mile Canyon near Boardman, OR.

This project will create additional capacity to support regional load growth, reliability needs and commercial requests for long-term transmission at a preliminary estimated direct cost of $250 million.

Estimated completion: Late 2027/Early 2028 (updated)

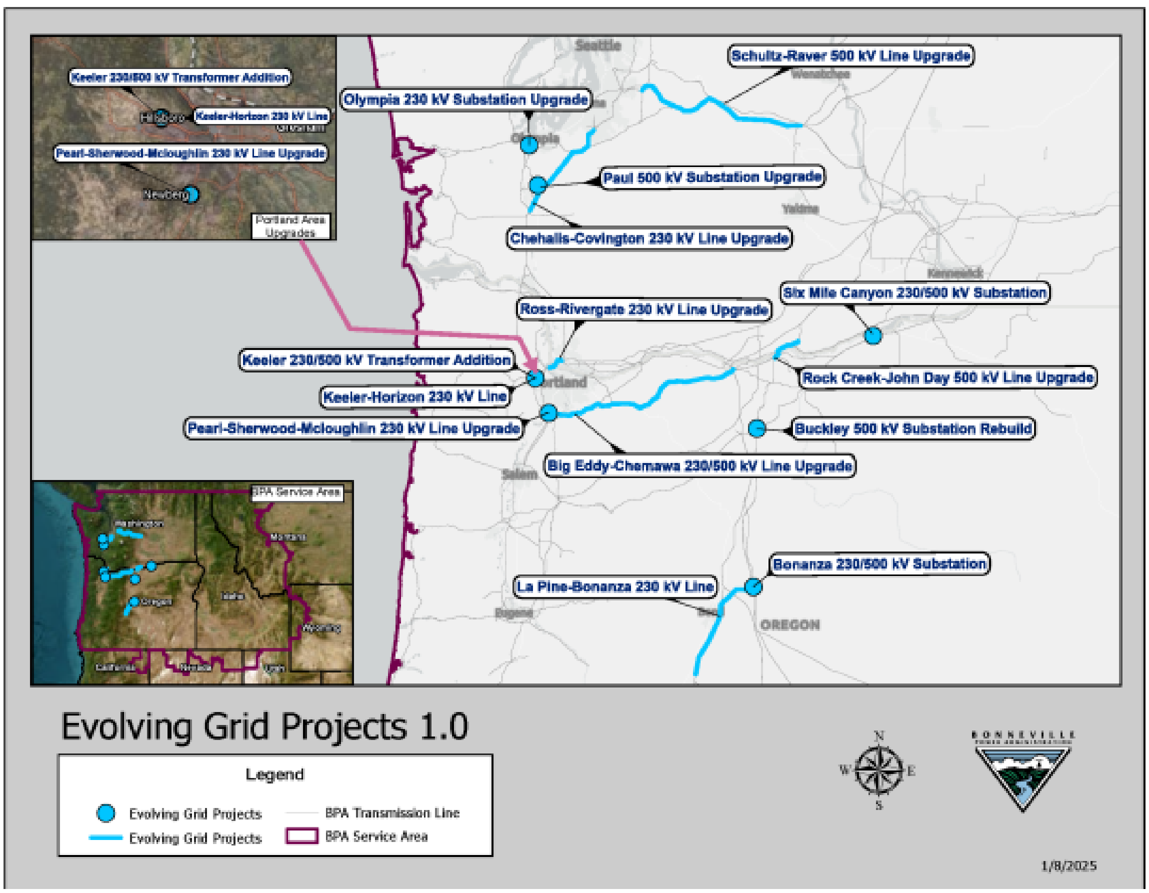
Buckley 500 kV Substation Rebuild

This project is a proposed rebuild of BPA's Buckley Substation in Sherman County, OR. It would be a new air-insulated 500-kV substation built near the existing gas-insulated substation, which will be retired.

This project will create additional capacity to support regional load growth, reliability needs and commercial requests for long-term transmission at a preliminary estimated direct cost of $150 million.

Estimated completion: 2028 (updated)

(continued)



Evolving Grid Project (EGP) 2.0 Summaries

EGP 2.0 consists of 13 proposed projects at a preliminary projected cost of $3 billion to support the region's electrification and clean energy goals.

Grand Coulee-Columbia-Schultz 500 kV Line Upgrade

This proposed project would rebuild the existing Grand Coulee-Olympia 287 kV circuit to 500 kV. To loop into Columbia, the project would also build a new Columbia 500 kV substation yard, with a 500/230 kV transformer bank. This section of the line would terminate at Schultz Substation.

Schultz-Olympia 500 kV Line Rebuild

This proposed project would rebuild the Schultz-Olympia portion of the Coulee-Olympia 287 kV to 500 kV. The project would also include an expansion of an Olympia 500 kV yard, a new 500/230 kV transformer bank, and three new 500 kV shunt capacitors.

Central Oregon 500 kV Dynamic Reactive Upgrades

This proposed project would install reactive support (STATCOM) for Central Oregon at Bonanza 500 kV and a Captain Jack 500 kV.

RATS: Reno-Alturas Reactive Addition

This proposed project would install reactive support (STATCOM) at Warner 115 kV and Hilltop 230 kV.

Salem Area Upgrades

These proposed upgrades would build on the Big Eddy-Chemawa project in EGP 1.0:

North of Marion Upgrade #1:

- Constructing a new 500 kV yard at Chemawa, including a new 500/230 kV transformer bank
- Rebuild the Pearl – Chemawa section of Big Eddy-Chemawa from 230 kV to 500 kV
- Rebuild the Chemawa – Santiam #1 from 230 kV to 500 kV

North of Marion Upgrade #2:

- Rebuild Pearl – Marion #1 500 kV transmission line and replace the 2.5" expanded conductor
- Rebuild the Oregon City – Chemawa 115 kV transmission line river crossing
- Add a second 230/115 kV transformer bank at Chemawa Substation

North of Pearl

This proposed project would upgrade transmission capacity in the Portland sub-grid North of Pearl area by reconductor the existing Pearl-Keeler #1 500 kV line and leveraging an existing corridor to add a second 500 kV line between Pearl and Keeler.

The existing Pearl-Sherwood #1 and #2 230 kV transmission lines would be relocated/rebuilt to accommodate Pearl-Keeler #2 500 kV line.

The existing section of Keeler-Oregon City #2 115 kV between Sherwood and Oregon City would be repurposed as the new Keeler-Sherwood (PGE) 115 kV Line, terminating into Sherwood.

Big Eddy-Quenett Creek 230 kV Line Upgrade

This proposed project would upgrade the Hood River sub-grid, rebuilding the Big Eddy-Quenett Creek 230 kV to resolve the river crossing impairment.

Ostrander-Pearl #1 500 kV Line Upgrade

This proposed project would upgrade the Ostrander-Pearl #1 500 kV line and replace the existing 2.5" expanded conductor.

Big Eddy-The Dalles Rebuild

This proposed project is currently under study with Northern Wasco PUD to rebuild a 115 kV line BPA currently leases.

Lower Columbia to Nevada-Oregon Border

Lower Columbia to Bonanza

This proposed project would build a new 500 kV transmission line between a substation in the Lower Columbia area and the planned Bonanza Substation in Central Oregon. It may include additional connections to 500 kV substations near the line route as well as new 500 kV series capacitors.

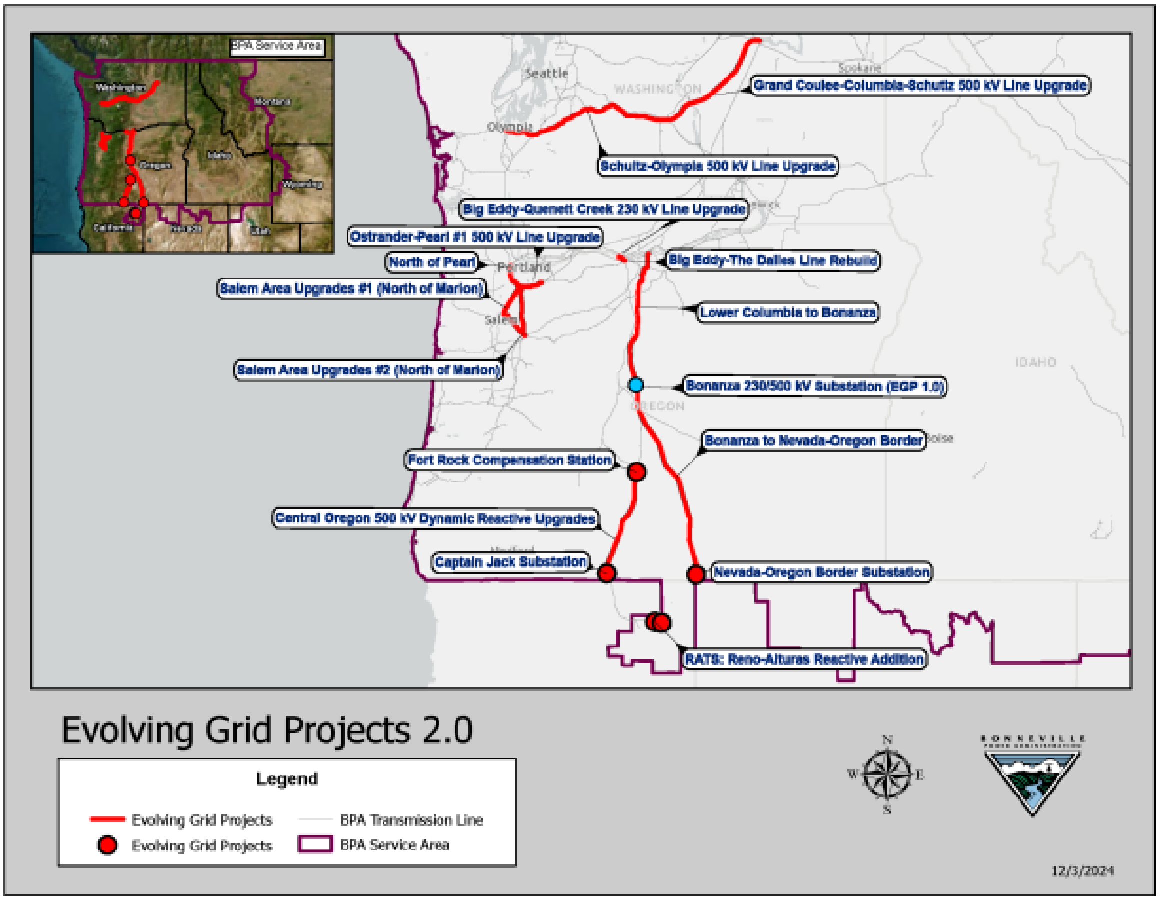
Bonanza to NOB

This proposed project would build a new 500 kV transmission line from Bonanza Substation toward the Nevada-Oregon border (NOB). The project would also include new 500 kV series capacitors.

Nevada-Oregon Border Substation

This proposed project would build a new 500 kV substation at the Nevada-Oregon border.

(continues)


BPA Service Area
Grand Coulee-Columbia-Schultz 500 kV Line Upgrade
Schultz-Olympia 500 kV Line Upgrade
Big Eddy-Quenett Creek 230 kV Line Upgrade
Ostrander-Pearl #1 500 kV Line Upgrade
North of Pearl
Big Eddy-The Dalles Line Rebuild
Salem Area Upgrades #1 (North of Marion)
Lower Columbia to Bonanza
Salem Area Upgrades #2 (North of Marion)
Bonanza 230/500 kV Substation (EGP 1.0)
Bonanza to Nevada-Oregon Border
Fort Rock Compensation Station
Central Oregon 500 kV Dynamic Reactive Upgrades
Captain Jack Substation
Nevada-Oregon Border Substation
RATS: Reno-Alturas Reactive Addition
Seattle
Olympia
Spokane
Portland
Salem
Boise
WASHINGTON
OREGON
IDAHO
Evolving Grid Projects 2.0
Legend
Evolving Grid Projects
Evolving Grid Projects
BPA Transmission Line
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12/3/2024

CASE: UE 452
WITNESS: BONNIE GARIETY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 404

Oregon Public Broadcast Article about Bonneville Transmission Expansion Projects

June 23, 2025

Bonneville Power Administration proposes $3B projects to improve power grid across PNW

By Monica Samayoa (OPB)
Oct. 17, 2024 3:22 p.m.

The Bonneville Power Administration, which owns more than 75% of the Pacific Northwest's high-voltage transmission lines, proposed more than a dozen new projects this week aimed at expanding the power grid.

BPA's proposals are intended to alleviate pressure on a grid facing rapidly increasing demands from the shift to renewable power, the electrification of cars and appliances, and the rise of technology companies' data centers that use massive amounts of electricity.

The Bonneville Power Administration Troutdale substation, right, and transmission towers, in Troutdale, Oregon, March 6, 2023.
Kristyna Wentz-Graff / OPB

The proposed 13 projects include additional equipment at substations, strengthening existing power lines and constructing new substations that would help meet electricity demand and improve the network's reliability across Oregon and Washington, BPA Senior Spokesperson Doug Johnson said.

"All of this is to stay out ahead of our customers' needs and ensure again that transmission network can handle all of the electricity traffic that needs to occur to light up data centers, homes, other businesses, all of the things that we use electricity for in the Northwest," he said.

The estimated price tag: about $3 billion. It comes a year after BPA proposed 10 other projects. Combined, they could cost about $5 billion for 23 proposed projects.

"These are in the early stages of development but go a long way toward meeting the needs of our customers which include investor owned utilities in Oregon, Washington and throughout the region to ensure that they have the energy they need and it can get across our transmission system to serve the growing energy needs that they have," he said.

Expanding the transmission grid is also necessary for the region to meet its clean energy goals.

Oregon's House Bill 2021 requires utilities, like BPA customer Portland General Electric, to have net-neutral carbon emissions by 2040. That means utilities need to increase the renewable energy portfolios and invest in more solar and wind energy as well as other renewable technologies that emerge. In Washington, the state is committed to reaching greenhouse gas emission-free electricity by 2045.

Nicole Hughes, executive director of the nonprofit Renewable Northwest, called BPA's new investments "exciting." Her organization, which advocates for renewable energy policies, had previously called on BPA to take the lead in improving the Northwest's power grid.

"These investments will help bring much needed clean energy to customers throughout the region," Hughes said in a statement. "We are eager to work with Bonneville to see these projects completed."

But Johnson said the proposed lines and expansions are not all focused on increasing renewable energy projects. Some of the proposals could be powered by fossil fuels, like natural gas.

"Renewables are certainly a large part, but it's also to ensure that our transmission network can get energy from one point to another," he said. Responding to increased electricity demand "is a huge part of this. You've got companies relocating to the Northwest. There are a lot of data centers in the Portland Metropolitan area in Central Oregon and other parts of the Northwest that need service."

The proposed projects emerged from a 2023 study that focused on energy needs created by new requests to use BPA's transmission lines. Johnson said the federal entity received about 16,000 megawatts of service requested needs.

BPA could add about 10,000 megawatts with the 13 transmission upgrades it has proposed.

On average, he said it takes about 1,000 megawatts per minute to power the city of Seattle.

For now, Johnson said these projects are in the early stages and could change as each goes through an environmental review. The smaller upgrades could happen in the next couple of years, while larger construction could take between seven to 10 years.

BPA also said it will spend more than $500 million for grid upgrades to help restore and preserve some of its more than 15,000 miles of existing lines, substations and other electrical equipment.

"We've been building transmission in the Northwest since the 1930," he said. "So a lot of these facilities are 80 years old, 70 years old, 60 years old. They need to be rebuilt — at some point the poles go bad."

CASE: UE 452
WITNESS: BONNIE GARIETY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 405

PGE Non-Confidential Data Response 041

June 23, 2025

May 23, 2025

To: JP Batmale
Oregon Public Utility Commission

From: Jaki Ferchland
Senior Manager, Pricing, Tariff, and Power Cost Recovery

Portland General Electric Company
UE 452
PGE Response to OPUC Data Request 041
Dated May 9, 2025

Request:

Please explain where the real power losses capacity rate described in PGE's Opening Testimony, page 11, lines 18-21, is located in the Monet model. Also identify the location of the corresponding rate in the BPA Rate Schedule or other documentation.

Response:

Please see PGE's response to OPUC Data Request No. 040. Line losses for transmission delivered via BPA transmission lines, which are a significant portion of PGE's line losses, are settled physically in MONET. This occurs in two steps:

1. The MONET team grosses up the load forecast entered into the model to account for these anticipated losses.
2. The model then simulates market purchases for the lost MWhs during transmission.

PGE would like to clarify this line in testimony, as it may have been misleading: PGE / 100 / Outama – Pedersen / 10 / 20–21, "PGE's monthly transmission bill would increase by approximately 22.9% resulting in an increase of $24.6 million to forecasted NVPC." PGE's monthly transmission bill is in fact increasing by 22.9%, however, that entire increase is not impacting NVPC (and thus not PGE customers) at this time. The capacity rate for BPA's real power losses is not an input in the MONET model given including the capacity rate in MONET would have constituted an enhancement and thus was not implemented. As a result, PGE's NVPC forecast does not reflect this real power losses capacity rate. If it were included, the price increase to customers would be higher than $24.6 million.

CASE: UE 452
WITNESS: BONNIE GARIETY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 406

PGE Non-Confidential Data Response 072

June 23, 2025

June 2, 2025

To: Scott Gibbens
Oregon Public Utility Commission

From: Jaki Ferchland
Senior Manager, Pricing, Tariff, and Power Cost Recovery

Portland General Electric Company
UE 452
PGE Response to OPUC Data Request 072
Dated May 19, 2025

Request:

On page 3 of PGE direct testimony by Outama – Pedersen, there is a proposed $24.6 million increase in net variable power cost due to updates in BPA transmission rates. Please provide the dollar amounts for the following items that make up the $24.6 million increase:

- Line 9 – "BPA is proposing an increase of 27% to the Long-term Firm Point-To-Point (PTP) rate"
- Line 12-13 – "BPA is proposing a 30% increase to the Scheduling, Control and Dispatch (SCD) Long-Term Firm rate."
- Line 18 – BPA is proposing a 130% increase to the Real Power Losses Capacity rate

Response:

The Long-term Firm Point to Point rate is responsible for $20.3M of the $24.6M.

The Scheduling, Control and Dispatch (SCD) Long-Term Firm rate is responsible for $4.1M of the $24.6M.

The Real Power Losses Capacity rate is not modeled in AUT and therefore is not part of the $24.6M increase. Please refer to PGE's response to OPUC Data Request No. 136 for more information on this, which will be submitted on June 10th, 2025.

CASE: UE 452
WITNESS: ZHUOYI ZHAO

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 500

REDACTED OPENING TESTIMONY

June 23, 2025

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

A. My name is Zhuoyi Zhao. I am a Senior Economist employed by the Energy Rates and Regulatory Strategy Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My Witness Qualifications Statement is found in Exhibit Staff/501.

Q. What is the purpose of your testimony?

A. I discuss Staff's analysis of the Western Energy Imbalance Market (WEIM) and the Extended Day-Ahead Market (EDAM) issues in Portland General Electric Company (PGE or the Company)'s 2026 Annual Power Cost Update Tariff (AUT), Docket No. UE 452.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared the following exhibits:

- Exhibit Staff/501, Witness Qualifications Statement.
- Exhibit Staff/502, Non-Confidential Responses to Data Requests.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1. WEIM 2
[redacted] 8
[redacted] 8
[redacted] 9
Issue 2. EDAM 11
Table 1. PGE Day-Ahead Market Participation Benefits Summary 15

ISSUE 1. WEIM

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

A. Operated by the California Independent System Operator (CAISO), the Western Energy Imbalance Market (WEIM) is a voluntary, regional, short-term energy market that allows participants to buy and sell power to balance generation and load in real-time. The WEIM system algorithmically finds and dispatches the lowest-cost energy for its market participants. This system is also helpful in managing congestion on transmission lines. Overall, the WEIM improves integration of resources, enhances grid reliability and promotes more efficient use of the regional transmission system.[1] As of October 2024, 22 balancing authorities in 11 states participate in the WEIM, representing close to 80 percent of demand in the Western Interconnection.[2]

Q. Please describe how the Company can benefit from the WEIM.

A. The Company can benefit from participating in the WEIM in multiple ways. For example, by selling (exporting) excess power to the market or buying (importing) power from the market at a lower cost compared with in-house generation, the Company incurs lower overall generation costs. When selling clean energy to meet load in a greenhouse gas (GHG) pricing area, the Company also receives additional GHG benefits. Another benefit to

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1 *See* Western Energy Imbalance Market website, (available at: https://www.westerneim.com/Pages/About/default.aspx) (last accessed on June 3 2025); Western Energy Imbalance Market, "How The Market Works," (available at: https://www.westerneim.com/Pages/About/HowItWorks.aspx) (last accessed June 3, 2025).

2 Elliot Mainzer, "CEO report to ISO Board of Governors and WEIM Governing Body" (October 31, 2024) (available at: https://www.westerneim.com/Documents/CEOReport-Nov2024.pdf).

participants is flexible ramping awards. The Company gains these awards by offering dispatchable ramping capability[3] to the CAISO to ensure reliability when there are errors in the forecasted net load of the WEIM. Moreover, the WEIM pools' varying generation capacities across the entire market footprint, which helps all participants meet their load more efficiently. This benefit from optimizing real-time dispatch is referred to as the flexibility reserve diversity benefit, which is incorporated in the WEIM's hourly resource sufficiency test.[4]

Q. Please summarize how the WEIM benefits can impact rate payers.

A. The WEIM gives the Company easy access to lower cost resources in an organized real-time market. These benefits—which manifest as a reduction to the cost to produce power—are modeled outside the Company's main dispatch model used to estimate forward-looking net power cost and are subtracted from the net power cost forecast, thus reducing the rates paid by customers.

Q. How does the Company track the WEIM benefits?

A. To forecast the WEIM benefits in AUTs, PGE uses historical WEIM price and trading limit data and relies on its proprietary dispatch model, MONET (the

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[3] Also referred to as "flexible ramping product" *see* Radha Madrigal, California ISO, "Flexible Ramping Product (FRP) Refinements – Deliverability", Slide 9 (September 7, 2022) (Available at: Presentation-Flexible-Ramping-Product-Refinements-Deliverability-Training.pdf.) and California ISO, "Flexible Ramping Product Revised Draft Final Proposal" (December 17, 2015) (Available at: https://www.caiso.com/Documents/RevisedDraftFinalProposal-FlexibleRampingProduct-2015.pdf.).

[4] For further information on the sufficiency test *see* Kyle Westendorf, California ISO, "Flexible Ramping Sufficiency Evaluation Presentation" (April 30, 2018) (available at: https://www.caiso.com/Documents/DMMResourceSufficiencyEvaluationPresentation-EnergyImbalanceMarketofferRulesTechnicalWorkshop.pdf.).

Multi-area Optimization Network Energy Transaction model), for estimation. The actual WEIM benefits are calculated using transaction data from the CAISO and a third-party platform, PCI P&L Analyzer.[5]

Q. Please describe whether the Company forecasts the abovementioned WEIM benefits.

A. PGE estimates the following three WEIM benefits in AUTs: **[BEGIN CONFIDENTIAL]**

[redacted] **[END CONFIDENTIAL]**

Another benefit is the flexibility reserve diversity benefit. Participation in the WEIM reduces the amount of generation (a MW reduction) PGE is

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5 Staff/502, Zhao/1-2, PGE response to Staff Data Request 27.

required to hold in reserve,[6] and the saved generation becomes available for sale. The Company does not forecast this benefit because the saved generation is made available to dispatch into the WEIM. Since the calculation of sub-hourly dispatch savings in AUTs uses historical actual data and the flexible ramping awards are also being forecasted, the saved generation has been incorporated in the estimation of the WEIM benefits.[7]

Q. What are the Company's forecasted WEIM benefits in the current filing?

A. The 2026 AUT includes **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].** [8]

Q. Are there costs associated with participating in the WEIM in this filing?

A. Yes. The CAISO recovers its operating costs, namely grid management charges, from wholesale customers who participate in the WEIM.[9] These charges in the 2026 AUT are **[BEGIN CONFIDENTIAL]** [redacted]

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6 This requirement is from the WEIM Resource Sufficiency Evaluation. The evaluation is performed prior to each hour and each balancing area must show sufficient ramping capability from the start of the hour to each of the four 15-minute intervals within the hour. For detailed information about this test, *see* California ISO, "Western Energy Imbalance Market Resource Sufficiency Evaluation Metrics Report covering July 2023" (August 31, 2023) (Available at: https://www.caiso.com/documents/q1-2025-metrics-report-on-resource-sufficiency-evaluation-in-weim-may-27-2025.pdf).

7 Staff/502, Zhao/3, Docket No. UE 436, PGE response to Staff Data Request 66.

8 PGE confidential workpaper, 19_EIM_2026AUT_Summary_Initial Filing, included in the Minimum Filing Requirements (MFRs) documents per Commission Order No. 08-505.

9 PGE/100, Outama – Pedersen/31.

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

Q. Has Staff reviewed the Company's WEIM benefits forecast in previous AUTs?

A. Yes. Staff has reviewed this forecast for a few years and examples of various adjustments made regarding PGE's forecast methodology are summarized as follows. In the 2025 AUT (Docket No. UE 436), the stipulating parties agreed to remove $6 million from the Net Variable Power Cost (NVPC) for a basket of issues including the WEIM diversity and neutrality benefits.[10] While this topic was not addressed in the 2024 general rate case and AUT filing (Docket No. UE 416), in the 2023 AUT (Docket No. UE 402), the stipulating parties agreed that PGE would include WEIM GHG award benefits in the forecast.[11] In the 2022 AUT (Docket No. UE 391), the parties agreed PGE would use the weighted average historical data in the GHG revenue forecast.[12] In the 2021 AUT (Docket No. UE 377), parties agreed to include the flexible ramping awards of $408,450 in the forecast and assume a higher GHG cost obligation.[13]

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10 *In the Matter of Portland General Electric Company, 2025 Annual Power Cost Update Tariff*, Docket No. UE 436, Order No. 24-406 at 4 (November 4, 2024).
11 *In the Matter of Portland General Electric Company, 2023 Annual Power Cost Update Tariff*, Docket No. UE 402, Order No. 22-427 at 2 (November 1, 2022).
12 *In the Matter of Portland General Electric Company, 2022 Annual Power Cost Update Tariff*, Docket No. UE 391, Order No. 21-380 at 3 (November 1, 2021).
13 *In the Matter of Portland General Electric Company, 2021 Annual Power Cost Update Tariff*, Docket No. UE 377, Order No. 20-390 at 3 (October 28, 2020).

Q. Please describe Staff's recommendations in this AUT.

A. Staff has two recommendations. First, Staff recommends that PGE revise its method for estimating sub-hourly WEIM dispatch benefits to be more forward-looking. These WEIM benefits have consistently been the majority portion in the total forecasted WEIM benefits. As previously described, for this forecast PGE heavily relies on historical information that is mainly driven by energy markets and the WEIM prices in the past. This is problematic because as shown in Confidential Figure 1a and 1b below,[14] PGE's forecast model more accurately predicts history, not the future. Staff asks PGE to propose a revision to this model for the next AUT that helps improve forecast accuracy and hold a workshop discussing the revised model prior to the 2027 AUT. This revision should account for the impact of PGE's participation in the extended day-ahead market (EDAM).

[BEGIN CONFIDENTIAL]

[14] Data are taken from PGE's confidential response to Staff Data Request 29, Attachment A.

[redacted]

[END CONFIDENTIAL]

Second, to improve forecast accuracy of the existing model, Staff recommends an upward adjustment of $986,466, or 9.1 percent, to the forecasted net WEIM benefits in this AUT. Over the past four years, despite adopting Staff's various recommendations to increase forecasted WEIM benefits, PGE's model still underestimates the actuals by a considerably large margin on average. Confidential Figure 2 below shows these forecast errors, where a negative (positive) percentage represents the degree of underestimation (overestimation):

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

The forecasted net WEIM benefits for 2025 was **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, but in Q1 2025 alone PGE has already earned **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[15] Staff believes it is likely that PGE's model underestimated the net benefits for 2025 by a large margin as well. To address this persistent under forecasting, Staff recommends using the most recent 2024 forecast error, 9.1 percent, to correct at least some of the underestimation issue in this AUT. Adopting this adjustment would result in an increase in the WEIM benefits, which would reduce overall NVPC by $986,466.

Q. Why did Staff settle on a 9.1 percent adjustment?

A. Staff considers 9.1 percent as a reasonable, perhaps overly generous amount. It matches 2024's forecast error and is well below the average forecast error of 17.3 percent per Confidential Figure 2.

[15] Data are taken from PGE's confidential response to Staff Data Request 29, Attachment A.

ISSUE 2. EDAM

Q. What is the Extended Day-Ahead Market (EDAM)?

A. The Extended Day-Ahead Market (EDAM) is a voluntary day-ahead energy market in the Western Interconnect, slated to commence operation in 2026.[16] The EDAM augments the already existing Western Energy Imbalance Market (WEIM) by allowing the participants to submit schedules and bids earlier, improving market efficiency.[17] While the EDAM is not yet running, there are no known reasons that suggest any delay in its operation in 2026. Initial participation in 2026 will be the California Independent System Operator (CAISO) and PacifiCorp. PGE intends to join on or before October 1, 2026,[18] and three additional utilities are expected to join in 2027.[19]

Q. Please summarize how the EDAM benefits can impact rate payers.

A. The EDAM gives the Company easy access to lower cost resources through more efficient market clearing and resource allocation. These benefits manifest as a reduction to the cost to produce power, thus reducing the rates paid by customers. In AUTs, these benefits are subtracted from the NVPC forecast.

Q. How does the Company plan to capture the EDAM benefits?

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16 PGE/100, Outama – Pedersen/29. (Participants can terminate with six months' notice without paying exit fees. To participate, a BA must either already be a WEIM participant or join both day-ahead and real-time markets simultaneously.)

17 California ISO, "Extended Day-Ahead Market Fact Sheet", (Available at: https://www.caiso.com/Documents/extended-day-ahead-market-edam-fact-sheet.pdf).

18 PGE/100, Outama – Pedersen/30.

19 *See* Western Energy Markets website, (available at: https://www.westerneim.com/Pages/ExtendedDayAheadMarket.aspx) (last accessed on June 17, 2025). For more updates on the EDAM by the CAISO, see (Available at: https://stakeholdercenter.caiso.com/StakeholderInitiatives/Extended-day-ahead-market).

A. The Company has been evaluating the option of using MONET to capture the EDAM benefits. Based on a study by The Brattle Group (Brattle), PGE states that MONET assumes the same day-ahead trading optimization as in the EDAM's automation tool. In other words, MONET's simulation of purchases and sales in the day-ahead market is consistent with how these transactions would be treated in the EDAM. However, MONET's limitations, such as the model does not fully capture real-world constraints and inefficiencies, can impact forecast accuracy. Currently, the Company is working on integrating with the EDAM and asserts that it will not know about most necessary refinements to MONET until the EDAM implementation is finalized.[20]

Q. What is the Company's anticipation of the EDAM benefits in this AUT?

A. The Company does not anticipate immediate power cost reductions for customers in 2026 for two reasons. One is the small number of participants (the CAISO, PacifiCorp, and PGE) in the EDAM in 2026. The other is the Company's short period (three months) of participation.[21]

Q. Are there costs associated with participating in the EDAM forecasted in this AUT?

A. Yes. The Company estimates the grid management charge for one quarter in 2026 to be approximately $2.5 million.

Q. What is Staff's opinion on the Company's assessment of the expected EDAM benefits in this filing?

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[20] PGE/100, Outama – Pedersen/31.
[21] PGE/100, Outama – Pedersen/30.

A. Staff disagrees and believes that an immediate power cost reduction for customers in 2026 is appropriate for two reasons. First, the CAISO is a substantial market. Taking energy trading in the WEIM as an example, in the WEIM monthly market performance report for February 2025, the CAISO and PacifiCorp East are the two leaders in daily WEIM transfer volume in both the five-minute and real-time markets. The daily volume of any other participant is only about half or even less.[22] In addition, the Brattle study indicates that one of PGE's primary benefits from the EDAM will be driven by replacing internal gas generation with lower cost market purchases, especially during high solar periods,[23] and the energy supply of the CAISO is mostly solar.[24]

Second, PGE's biggest trading paths are with California (via Malin), PacifiCorp and Bonneville Power Administration (BPA).[25] The Brattle study models PGE's simultaneous export and import limit as about 5,000 MW. PGE's export and import quantity with the CAISO is about 1,291 MW,[26] and with PacifiCorp is about 500 MW. That is, the two other participants in the EDAM in 2026 already represents 36 percent of PGE's trading limit. Taken together,

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22 *See* Figure 44 to 89 in "February 2025 Monthly Market Performance Report" (Available at: https://www.caiso.com/content/monthly-market-performance/feb-2025/western-energy-imbalance-market.html#weim-transfers) (last accessed June 17, 2025).

23 PGE/102, Outama – Pedersen/34.

24 Solar energy accounts for about 78.9 percent of the CAISO's energy supply as of June 17, 2025. See https://www.caiso.com/todays-outlook/supply for daily information on the CAISO's energy supply mix.

25 PGE/102, Outama – Pedersen/36.

26 In the Brattle study, PGE's export and import quantity with both the CAISO and the Balancing Authority of Northern California/the Sacramento Municipal Utility District (BANC/SMUC) is 1,677 MW, of which the CAISO proportionally accounts for 77 percent, or 1,291 MW. This proportion is derived based on the bidirectional trading volumes among the CAISO, BANC/SMUC and Malin. Specifically, the bidirectional trading volume between the CAISO and Malin is about 2,500 MW (or 77 percent) and that between BANC/SMUD and Malin is an average of 750 MW (or 23 percent).

Staff concludes that PGE has underestimated the EDAM benefits it will gain in 2026 and believes that the amount of these benefits should not be negligible.

Q. Does Staff recommend an adjustment?

A. Yes. Staff recommends a $0.96 million forecast for the EDAM benefits in this AUT. This results in a reduction to the NVPC by the same amount.

Q. Please explain.

A. In the Brattle study, the business-as-usual (or BAU) case assumes that the day-ahead market remains a bilateral market and that current WEIM and the Western Energy Imbalance Service (WEIS) members remain in those markets. The WEIM Transition case assumes that PGE joins the EDAM with entities announced to join EDAM and IPCO, while other entities remain as they are in the BAU case. As the study shows (Table 1 below), compared to the BAU case, the WEIM Transition case brings PGE $10.6 million more benefits per year. Staff calculates 36 percent of this total amount to be $3.82 million and one quarter of it is $0.96 million.

TABLE 1. PGE DAY-AHEAD MARKET PARTICIPATION BENEFITS SUMMARY

Portland General Electric System Cost by Case ($ Millions)

		BAU	WEIM Transition
Market Membership	**Metric**	**EIM Only**	**EDAM**
Adjusted Production Cost	Cost	$332.3	$327.0
Wheeling Revenues	Revenue	$1.7	$0.1
Trading Revenues:			
Bilateral	Revenue	$2.41	$5.33
WEIM	Revenue	$15.71	$8.57
Mkt+ RT/WEIS	Revenue	-	-
EDAM	Revenue	-	$11.06
Markets	Revenue	-	-
Total System Cost		**$312.5**	**$301.9**
Benefit to BAU			**$10.6**

Q. Does Staff have other recommendations?

A. Yes. Staff recommends monitoring and evaluating PGE's EDAM model in future AUTs, because:

1. Despite that MONET may reflect the key elements of trading in the EDAM, it is unclear whether or not MONET's forecast of the EDAM benefits is reliable. As an example, PGE's forecast for the WEIM benefits simulates the hourly trading in the WEIM. Regardless, since the inputs the Company uses are heavily backward-looking, the WEIM benefits forecasts reflect the history more than the future.[27]

[27] See Staff/500, Zhao/8.

2. As noted in the Brattle study, MONET’s trading results fail to capture certain EDAM revenues such as congestion revenue. In addition, the study points out that MONET does not allow the EDAM trade revenues and loss of wheeling revenue on bilateral trades to be directly calculated.[28]

Q. Does this conclude your testimony?

A. Yes.

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28 PGE/102, Outama – Pedersen/71.

CASE: UE 452
WITNESS: ZHUOYI ZHAO

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 501

Witness Qualifications Statement

June 23, 2025

WITNESS QUALIFICATIONS STATEMENT

NAME: Zhuoyi Zhao

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Economist, Energy Costs Division

ADDRESS: 201 High St. SE, Ste. 100
Salem, OR 97301-3612

EDUCATION: PhD, Accounting
Wilfrid Laurier University,
Canada

Master of Applied Finance and Banking
University of Wollongong,
Australia

Bachelor of Arts, English
Jilin International Studies University,
China

EXPERIENCE: I am a Certified Management Accountant (CMA). I have been employed by the Public Utility Commission of Oregon in the Energy Costs Division since January 2025. My responsibilities include providing research, analysis, and recommendations on a range of regulatory filings. Prior to joining the Commission, I was employed by St. Norbert College as an Assistant Professor in Accounting where I developed and taught various classes in accounting, including Managerial Accounting, Financial Accounting, Accounting Information Systems, and Data Analytics.

CASE: UE 452
WITNESS: ZHUOYI ZHAO

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 502

Non-Confidential Responses to Data Requests

June 23, 2025

May 12, 2025

To: Julie Dyck
Oregon Public Utility Commission

From: Jaki Ferchland
Senior Manager, Pricing, Tariff, and Power Cost Recovery

Portland General Electric Company
UE 452
PGE Response to OPUC Data Request 027
Dated April 28, 2025

Request:

Please provide a detailed narrative (with equation and/or formulae) on the similarity between PGE's methodology for calculating forecasted EIM benefits and its methodology for calculating actual EIM net benefits. In particular, please specify how each variable in MONET's calculation of forecasted EIM benefits can be mapped to one or more variables in PGE's calculation of actual EIM benefits.

Response:

EIM benefit calculations can be found in Vol 1 – Curves and Contracts > EIM. PGE calculates benefits for sub-hourly dispatch, GHG benefits, CAISO Flex Awards, and includes grid management charges as a cost.

PGE's methodology for calculating forecasted EIM net benefits is conceptually similar to the one used for calculating actual EIM net benefits. The key differences are:

	MONET	Actual
Sub-hourly dispatch	Dispatch uses 3-year average of EIM prices and historical trading limits to instruct sub-hourly redispatch against the costs of incremental generation incurred or avoided.	PCI P&L Analyzer compiles bid and awards data, locational marginal prices, dispatch instructions, and settlement calculation parameters to calculate CAISO credits and charges, which is compared against the costs of incremental generation incurred or avoided.
GHG Benefit	Historical quantity valued at forward price and implied	Actual benefits

	emissions rate, which is derived from a 3-year average of GHG award historical prices ($/MWh) divided by the 3-year average of GHG allowance historical prices ($/mTCO$_2$).	
CAISO Flex Awards	3-year average	Actual awards
Grid Management Charges	Historical data plus escalation	Actual charges

July 31, 2024

To: Brian Conway
Oregon Public Utility Commission

From: Jaki Ferchland
Senior Manager, Revenue Requirement

Portland General Electric Company
UE 436
PGE Response to OPUC Data Request 066
Dated July 17, 2024

Request:

Please demonstrate how the Company's flexible reserve diversity benefits are already modeled/included in the Monet model through both a narrative description as well as pointing to where these benefits can be found in the Monet Model.

Response:

After passing the resource sufficiency test, the "freed up" capacity that PGE held out in previous market timeframes for uncertainty is made available for EIM to dispatch. This "freed-up" capacity is accounted for in PGE's resource trading limits, which are used to calculate the sub-hourly dispatch benefits included in the NVPC forecast as part of the overall EIM net benefits. Additionally, to the extent CAISO issues flexible ramping awards to PGE, this revenue is included as part of the EIM net benefit calculation as well. The volume of trades in MONET are based upon a three-year historical average of actual trades. It is these "trading limits" in MONET, which contain the diversity reserves. See March 14, 2024 Update, Volume 1 - Forward Curves, EIM.

CASE: UE 452
WITNESS: CHARLES LOCKWOOD

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 600

REDACTED
Opening Testimony

June 23, 2025

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

A. My name is Charles Lockwood. I am a Utility and Energy Analyst employed in the Energy Program of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

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

Q. What is the purpose of your testimony?

A. I discuss Portland General Electric's (PGE or the Company) Battery Energy Storage System (BESS) projects including the Seaside BESS, and the Northwest Natural (NW Natural) Call Option.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared the following exhibits:

- Staff Exhibit 601 – Witness Qualifications Statement
- Staff Exhibit 602 – PGE Response to Staff DR No. 141
- Staff Exhibit 603 – PGE CONF Response to Staff DR No. 147

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1. Battery Energy Storage System 2
Issue 2. Northwest Natural Call Option 6

ISSUE 1. SEASIDE BATTERY ENERGY STORAGE SYSTEM

Q. Please describe the discussion of PGE's battery energy storage system (BESS) projects included in its Annual Power Cost Update (APCU) Tariff filing.

A. PGE's APCU filing discusses batteries in a limited capacity, with the majority of the discussion focusing on an adjustment related to the Seaside BESS. Any discussion of batteries in the filing not explicitly discussing the Seaside BESS serves as minor discussions in MONET modeling and generation mix impacts in the subsequent exhibits.

PGE currently has three large scale standalone battery energy storage systems in operation: Coffee Creek, Constable, and Sundial, each of which was procured via the 2021 All-Source Request for Proposal (RFP).[1] Additionally, PGE has one large scale BESS under construction, Seaside. In total, PGE's 2023 RFP has roughly 1.3 GWs of standalone nameplate BESS capacity included on the 2023 RFP Final Shortlist, for which negotiations are underway.

Q. Please provide a brief description of the Seaside BESS project.

A. The Seaside BESS project is a lithium-ion BESS with a 200 MW nameplate capacity and four-hour storage capability (i.e., total energy discharge of 800 MWh over four hours) that will be located in North Portland. Currently, the project is expected to be placed into service in June 2025.

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[1] Staff/602, PGE Response to Staff DR No. 141.

Q. Please provide a brief description of the Seaside BESS adjustment procedural history.

A. On November 14, 2024, the Company originally included the Seaside BESS project in the 2025 NVPC. The Commission subsequently removed the project in Order No. 24-406, stating if the cost of the Seaside investment was not approved for inclusion in customer prices in 2025 through a tracking mechanism, the related NVPC would be removed for the full 2025 NVPC forecast.[2] Recovery of PGE's request for a tracking mechanism to recover costs of the Seaside BESS was denied in Commission Order No. 24-454, though the Commission invited the Company to seek recovery in a separate filing in 2025.

Q. Has the Company filed to seek recovery for the Seaside BESS in 2025?

A. Yes. On May 30, 2025, the Company filed a request for recovery of the Seaside BESS project in Docket No. UE 455 through the creation of Schedule 120, Seaside Battery Storage Resource Alternative Recovery Mechanism. The Company requested an effective date of June 30, 2025.

Q. Given the Company has yet receive approval for the recovery of the Seaside BESS, are the impacts of the investment found in this APCU filing?

A. Yes. The Company states "to match the costs and benefits, PGE is forecasting Seaside in the 2026 NVPC forecast."[3]

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2 PGE/100, Outama-Pedersen/2.
3 PGE/100, Outama-Pedersen/2.

Q. Please describe the costs and benefits forecasted for the Seaside BESS.

A. According to the Company, Seaside BESS is a vital asset furthering PGE's efforts toward House Bill 2021 clean energy mandates. Additionally, the investment provides critical capacity to PGE's grid enhancing grid reliability, managing costs by optimizing energy storage and release, and better supporting renewable energy integration.[4]

PGE currently estimates that the Seaside BESS investment would impact approximately 953,000 Cost of Service (COS) customers, with an increase of 1.5 percent in COS revenues, or $46.6 million from the proposed Schedule 120 prices.[5] PGE states that an average Schedule 7 customer consuming 784kWh monthly would see a bill increase of $2.09, or 1.3 percent. Staff emphasizes these costs however are not directly flowing through the APCU filing, but rather would be recovered though Schedule 120 charged to most customer classes. The prudence and reasonableness of which will be discussed in Docket No. UE 455.

Q. Is it appropriate to include the costs and benefits of the Seaside BESS in this APCU filing, given the Commission has not approved cost recovery?

A. Yes. The purpose of the APCU is to forecast the NVPC for the upcoming year. The investment is set to be operational June 2025, and therefore, if brought on-

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4 Docket No. UE 455, PGE's Initial Filing, https://edocs.puc.state.or.us/efdocs/UAA/ue455uaa337138026.pdf

5 Id.

line, will directly impact the 2026 NVPC. Staff will have opportunity to update its recommendation if the Seaside Battery does not come online or some other circumstance supports excluding Seaside from PGE's 2025 NVPC. At this time however, Staff agrees with PGE that the best course is to include the resource in the forecast of NVPC.

ISSUE 2. NORTHWEST NATURAL CALL OPTION

Q. Please describe the NW Natural Gas Call Option.

A. Since 2010, PGE and NW Natural have worked together under a Winter Peaking Agreement, which provides NW Natural with a call option for up to 30,000 Dth/day during the Winter heating season of November 1 through March 31, annually.[6] NW Natural pays PGE a price based on the Ultra Low Sulfur Biodiesel when it elects to purchase the 30,000 Dth of natural gas. PGE states that this pricing agreement aligned well with PGE's dual fuel capability at the Beaver Generating Station (Beaver).[7] However, the dual fuel capability at Beaver will end in 2026, meeting the conditions needed to renegotiate the pricing structure in the contract.

Q. Please describe the new pricing structure.

A. Given the requirement to renegotiate the contact, PGE and NW Natural agreed to reprice based on PGE's Minimum Filing Requirements (MFRs). If PGE had not restructured the current agreement and received revenue from NW Natural based on the price of diesel, absent the ability to use diesel as a fuel source at Beaver, PGE's customers would have been exposed to incremental cross commodity risk.

The revised NW Natural Winter Peaking Agreement now reflects **[BEGIN CONFIDENTIAL]** [redacted]

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[6] PGE/100, Outama-Pedersen/40.
[7] PGE/100, Outama-Pedersen/40.

[redacted] **[END CONFIDENTIAL]**[8]

Q. How does the change in the NW Natural Gas Call Option impact PGE's gas storage?

A. Due to the change in the NW Natural Gas Call Option, PGE has increased the ending February inventory balance at North Mist from 1.2 million Dth to 1.320 million Dth.[9] The increase in the ending February inventory balance increases PGE's NVPC by $0.7 million.

Q. Why does the change in the NW Natural Gas Call Option create the need for an incremental increase in North Mist inventory balance?

A. PGE states the Company requires increased inventory in the winter, because after 2026 PGE can no longer rely on any amount of oil as a backup fuel if NW Natural exercises its option to purchase gas from PGE.[10] Therefore, the Company will match NW Natural's gas purchases with a combination of various power purchases and North Mist gas storage inventory. In 2026, the Company states it will rely mostly on power purchases, North Mist gas storage inventory, and the availability of the one remaining unit at the Beaver Generation Station

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8 Staff/603, PGE CONF Response to Staff DR No. 147.
9 PGE/100, Outama-Pedersen/41.
10 PGE/100, Outama-Pedersen/41.

with dual fuel capability, subject to limitations under the Oregon Department of Environmental Quality air permit.

Q. Please describe Staff's review process and findings.

A. Staff has reviewed PGE's MFRs regarding the NW Natural Gas Call Option in Volume 3, Thermal Plant Gas Storage Constraints. Additionally, Staff asked a series of data requests to better understand the adjustment and the renegotiation of PGE and NW Natural's existing contact.

Q. Does Staff have any adjustments?

After reviewing PGE's MFRs and data requests responses, Staff does not have any concerns with the $0.7 million adjustment to the 2026 NVPC as filed by the Company.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 452
WITNESS: CHARLES LOCKWOOD

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 601

Witness Qualifications Statement

June 23, 2025

WITNESS QUALIFICATIONS STATEMENT

NAME:	Charles Lockwood
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Utility Analyst Utility Strategy and Integration Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	University of Florida Bachelor of Science in Environmental Science, 2019 University of Oregon Juris Doctor, 2022 Concentrations in Green Business Law, Environmental and Natural Resources Law
EXPERIENCE:	Oregon Public Utility Commission Administrative Hearings Division Law Clerk, 2021-2022 Oregon Public Utility Commission Utility Analyst, 2022 - Present

CASE: UE 452
WITNESS: CHARLES LOCKWOOD

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 602

Portland General Electric's Non-Confidential Response to Staff Data Requests (DRs) No. 141

June 23, 2025

June 11, 2025

To: Scott Gibbens
Oregon Public Utility Commission

From: Jaki Ferchland
Senior Manager, Pricing, Tariff, and Power Cost Recovery

Portland General Electric Company
UE 452
PGE Response to OPUC Data Request 141
Dated May 28, 2025

Request:

Please explain if the Company is actively procuring new battery energy storage systems, or if the Company has already procured new battery energy storage systems that are active.

Response:

PGE has three large scale standalone battery energy storage systems in operation (Coffee Creek, Constable, and Sundial) and one that is currently under construction (Seaside).

PGE's 2023 RFP has roughly 1.3 GWs of standalone nameplate battery storage capacity included on its 2023 RFP Final Shortlist, for which negotiations are still underway. PGE also has its Draft 2025 All-Source RFP in UM 2371, which will seek to add additional capacity resources.

CASE: UE 452
WITNESS: CHARLES LOCKWOOD

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 603

Portland General Electric's Redacted Responses to Staff Data Request (DRs) No. 147

June 23, 2025

June 11, 2025

To: Scott Gibbens
Oregon Public Utility Commission

From: Jaki Ferchland
Senior Manager, Pricing, Tariff, and Power Cost Recovery

Portland General Electric Company
UE 452
PGE's CONFIDENTIAL Response to OPUC Data Request 147
Dated May 28, 2025

Request:

Please elaborate further on the decision to reprice based on the terms shared in PGE's MFR. Provide or point to the workpapers utilized by the Company when agreeing with NW Natural to reprice.

Response:

PGE objects on the basis that this requires new analysis. PGE repriced the agreement to reduce cross commodity risk. Without waiving this objection, PGE responds as follows:

As discussed in PGE Exhibit 100, Section H, the agreement was originally structured to mirror operational capability at Beaver (i.e., the ability to dispatch using diesel oil). Oil dispatch will no longer be possible given the Beaver unit upgrades. The repricing decision was due to the loss of these dual fuel capabilities at the Beaver generation plant.
If PGE were to retain the current agreement structure and receive revenue from NWN based on the price of diesel, absent the ability to use diesel as a fuel source at Beaver, PGE's customers would be exposed to incremental cross commodity risk in this alternative.

The amended NWN Winter Peaking Agreement reflects **[BEGIN CONFIDENTIAL]** [redacted] **ND CONFIDENTIAL].**

CASE: UE 452
WITNESS: Luz Mondragon

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 700

REDACTED
OPENING TESTIMONY

June 23, 2025

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

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

Q. Please describe your educational background and work experience.

A. My Witness Qualifications Statement is found in Exhibit Staff/701.

Q. What is the purpose of your testimony?

A. I discuss the relationship between the Company's Integrated Resource Plan (IRP) and their 2026 Automatic Update Tariff (AUT) filing.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared the following exhibits:

- Exhibit Staff/701, Witness Qualifications Statement
- Exhibit Staff/702, Exhibits in Support of Opening Testimony

ISSUE 1. INTEGRATED RESOURCE PLAN (IRP)

Q. How are the IRP and AUT related?

A. The IRP is the utility's long-term plan for selecting the lowest-cost, least-risk mix of resources to meet customer needs. The AUT, by contrast, updates customer rates based on the projected short-term costs of operating those resources. The two are linked because the AUT should reflect the operational impacts of resources identified in the IRP. Effectively, the IRP guides what the utility builds and the AUT reflects how those choices affect rates.

Q. Why is alignment between the IRP and the AUT important?

A. Alignment is critical because it ensures that the cost forecasts used to set customer rates are grounded in the same planning logic and resource assumptions that were reviewed and vetted in the IRP process. Plan progress is an important assessment as this allows Staff to evaluate the Company's ability to plan for and procure the least cost, least risk resources that ultimately translate to customer prices.

Q. Does the resource mix in the Net Variable Power Cost (NVPC) forecast align with the resource strategies and action plan acknowledged in the 2023 IRP?

A. Not entirely. The Company's acknowledged action plan includes action items to conduct one or more RFPs to acquire sufficient energy and capacity to meet forecasted 2028 needs. The energy and capacity needs include 753 MWa of energy, roughly 251 MWa per year, and 905 MW of Summer and 787 MW of winter capacity through 2028.[1] The NVPC forecast for this power cost update does not yet include resources sought through the energy and capacity action items.[2]

Staff also notes the Company's progress on its Community-Based Renewable Energy (CBRE) resource action item, "PGE has issued a CBRE request for offers to market in close collaboration with OPUC Staff and will review offers made through the end of 2025."[3]

Q. Does the resource mix in the NVPC forecast align with the 2021 and 2023 all source RFP final short lists?

A. Yes. PGE included in the mix four resources from the 2021 All-Source RFP: the 311 MW Clearwater Wind facility, the 75 MW Constable Battery Energy Storage System, the 200 MW Seaside BESS, and the 200 MW Troutdale BESS. No resources on the acknowledged short list from a 2023 RFP are included in the 2026 AUT because they are anticipated to come on in 2027 and 2028 as negotiations are still ongoing.[4]

Q. Does Staff have any observations related to the connection between the Company's long-term planning and its current power cost forecast?

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1 *In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, 2023 Clean Energy Plan and Integrated Resource Plan.* LC 80, Commission Order No. 24-096 (April 18, 2024) Appendix A, page 5. Available at: https://edocs.puc.state.or.us/efdocs/HAC/lc80hac154444.pdf.

2 Staff/702, PGE responses to DR 45 and DR 77.

3 Id.

4 Staff/702, PGE response to DR 76.

A. Yes. As discussed in the 2023 IRP, the Company is implementing a nimble procurement strategy to meet its energy and capacity acquisition targets under changing conditions. In its 2023 RFP, the Company identified 85 MWa of non-emitting energy resources, with 343 MW of capacity contribution, and 695 MW of dispatchable capacity projects. On balance, Company's decision to delay a portion of its energy resource procurement to later in the action plan window was determined to strike a reasonable balance of costs and risk given complex circumstances, but it is worth noting that it may expose the Company to elevated market price, wheeling, and fuel cost risk in NVPC. Staff will continue to monitor the impact on NVPC and look for opportunities to mitigate the risk.

Q. Provide an example that highlights Staff's purpose in analyzing the relationship between the Company's planning logic and their resource assumptions and acquisitions.

A. In testimony, PGE states that the Company is currently exposed to potential capacity shortages during Summer 2026. PGE uses the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** The impact of the shortage is estimated at a $4.2 million NVPC increase.[5]

[5] PGE/100, Outama-Pedersen/19-21.

When Staff inquired about the capacity shortage and whether it was anticipated during the IRP process, PGE stated that the capacity shortage was foreseen. The Company explains that as a result of the RFP evaluation of the bids against market purchases for the purpose of evaluating the least-cost, least-risk options, the Company selected other resources in the RFP.[6] During the 2023 RFP process the Company explained that the Final Short List (FSL) is intended to mitigate near-term customer cost impacts by prioritizing capacity and limiting procurement with a cost impact metric.[7] The explanation was given in regards to PGE's non-emitting resources, yet PGE did not apply the same "intent" to the 2026 Summer capacity and failed to prioritize foreseen capacity shortfalls.

Q. Does Staff have a recommendation?

A. Not in this docket. For the purposes of fair, just and reasonable ratemaking, it is important for Staff to review progress on plan action items and assumptions made during the planning process in order to hold customers harmless for decisions made by the Company and identify opportunities to mitigate impacts to elevated market exposure and resource adequacy risks. Staff will continue to monitor the relationship between the Company's acknowledged IRP and its actual actions and the potential cost consequence of misalignment of the two in the future.

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6 Staff/702, PGE response to DR 138.

7 *In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, 2023 All-Source Request for Proposals, Request for Partial Waiver of Competitive Bidding Rules.* UM 2274, Staff Report (11/12/2024).

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 452
WITNESS: LUZ MONDRAGON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 701

Witness Qualifications Statement

June 23, 2025

WITNESS QUALIFICATIONS STATEMENT

NAME:	Luz Mondragon
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Financial Analyst Rates, Safety and Utility Performance Program (RSUP)
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	Western Governors University Bachelors of Science in Accounting
EXPERIENCE:	I have been employed with the PUC since March of 2023 as a Senior Finance Analyst tasked primarily with research and analysis of utility company filings, including, affiliated interests and rate case dockets. I have over 15 years of accounting/finance experience, most recently working for Northern Wasco County PUD as a Finance Analyst. My duties included financial reporting, internal and external, as well as budgeting. I also worked very closely with the Engineering team on work orders, inventory, capital budgets and Plant assets.

CASE: UE 452
WITNESS: LUZ MONDRAGON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 702

Exhibits in Support
Of Opening Testimony

June 23, 2025

May 28, 2025

To: Scott Gibbens
Oregon Public Utility Commission

From: Jaki Ferchland
Senior Manager, Pricing, Tariff, and Power Cost Recovery

Portland General Electric Company
UE 452
PGE Response to OPUC Data Request 045
Dated May 14, 2025

Request:

Regarding action item "CBRE Action: Issue RFP for all available and qualifying CBRE resources amounting to 66 MW by 2026," please provide the following:

a. Have any contracts for CBRE resources been entered into?
   i. If so, are any of the resources included in this Power Cost Update?
   ii. If so, provide the
      1. Docket in which the RFPs were reviewed
      2. Resulting contracts

b. Of the 66 MW CBRE resources identified how many have been acquired through
   i. December 2024.
   ii. April 2025.

c. Does PGE foresee meeting the MWs identified by 2026?
   i. If not, identify the deviation amount, and
   ii. Provide an explanation for the deviation.

Response:

a. As of today, no contracts have been entered into for CBRE, and thus no resources are currently included within the 2026 AUT. PGE has issued a CBRE request for offers to market in close collaboration with OPUC Staff and will review offers made through the end of 2025.
   i. Not applicable.
   ii. As the Request for Offers (RFO) is not subject to the competitive bidding rules, there is no docket within which the RFO was formally reviewed. PGE has worked closely with OPUC Staff and impacted stakeholders to develop the RFO, including through a series of public workshops and ongoing update meetings with Staff. All materials reviewed as part of RFO development are available at pgn.com/cbre.

b. See part (a).

c. PGE may acquire resources if the pricing and value is consistent with what was modeled in the acknowledged 2023 IRP, consistent with Commission direction in Order No. 24-097.

May 28, 2025

To: Scott Gibbens
Oregon Public Utility Commission

From: Jaki Ferchland
Senior Manager, Pricing, Tariff, and Power Cost Recovery

Portland General Electric Company
UE 452
PGE Response to OPUC Data Request 047
Dated May 14, 2025

Request:

Regarding action item "Capacity Action: Conduct one or more RFPs to acquire sufficient capacity to meet forecasted 2028 needs of 905 MW summer capacity and 787 MW winter capacity.," please provide the following:

a. Have any contracts for the forecasted 2028 needs been entered into?
   i. If so, are any of the resources included in this Power Cost Update?
   ii. If so, provide the
      1. Docket in which the RFPs were reviewed
      2. Resulting contracts
b. Of the forecasted 2028 resources needed how many have been acquired through
   i. December 2024.
   ii. April 2025.
c. Does PGE foresee meeting the forecasted needs by 2028?
   i. If not, identify the deviation amount, and
   ii. Provide an explanation for the deviation.

Response:

PGE objects to this request on the basis that the information it seeks is not relevant or reasonably calculated to lead to the discovery of admissible evidence in the current proceeding, given this proceeding relates solely to the 2026 forecast of Net Variable Power Costs. Without waiving this objection, PGE responds as follows:

a. No new capacity contracts have been entered into through the 2023 RFP or other RFPs that impact forecasted 2026 NVPC.
b. See part a.
c. See objection and see PGE's response to OPUC Data Request 046.

June 4, 2025

To: Scott Gibbens
Oregon Public Utility Commission

From: Jaki Ferchland
Senior Manager, Pricing, Tariff, and Power Cost Recovery

Portland General Electric Company
UE 452
PGE Response to OPUC Data Request 076
Dated May 19, 2025

Request:

Please explain how the resource selections from the 2020 and 2023 RFPs are reflected in the 2026 AUT forecast.

Response:

PGE did not conduct a 2020 RFP. As a result of the 2021 All-Source RFP, PGE executed contracts with four resources: the 311 MW Clearwater Wind facility, the 75 MW Constable Battery Energy Storage System, the 200 MW Seaside BESS and 200 MW Troutdale BESS.

Clearwater includes PGE-owned and power purchase agreements. Generation profiles and costs are included in the 2026 AUT forecast, with appropriate adjustments consistent with the Commission's UE 427 order.

Constable and Seaside are utility-owned, while Troutdale is available via a third-party capacity storage agreement. All three projects are included in the 2026 forecast.

The Commission acknowledged PGE's 2023 All-Source RFP final shortlist in November 2024. Negotiations are continuing, and PGE does not anticipate CODs in 2026. PGE has not included any 2023 RFP resources in the 2026 AUT.

June 4, 2025

To: Scott Gibbens
Oregon Public Utility Commission

From: Jaki Ferchland
Senior Manager, Pricing, Tariff, and Power Cost Recovery

Portland General Electric Company
UE 452
PGE Response to OPUC Data Request 077
Dated May 19, 2025

Request:

Does the resource mix in the NPC forecast match the preferred portfolio from the 2023 IRP in terms of capacity, location and fuel type? If not, please explain the differences and the reasons for them.

Response:

PGE's final 2023 IRP Preferred Portfolio is summarized in Table 3 of PGE's Response to Staff's Round 2 Comments and Recommendations.[1] The reporting of the final Preferred Portfolio does not specify geographic location of proxy resources, as details depend on commercial factors assessed through the RFP.

The cumulative additions to the resource mix shown in the 2026 column reveal differences versus the NPC forecast. The NPC forecast does not include the 321 MW wind or 74 MW storage added in the preferred portfolio. The IRP preferred portfolio amounts are based on analysis of proxy resource assumptions, not commercial opportunities. For more information on the 2023 RFP as it relates to the 2026 capacity needs, see OPUC Data Request No. 138, which will be filed on June 10, 2025.

The 2026 NVPC forecast does not include a forecast of CBRE. See response to OPUC Data Request No. 045 for more details. See PGE's response to OPUC Data Request No. 043 for additional discussion of EE.

[1] LC 80, November 21, 2023, available at: https://edocs.puc.state.or.us/efdocs/HAC/lc80hac154444.pdf

June 10, 2025

To: Scott Gibbens
Oregon Public Utility Commission

From: Jaki Ferchland
Senior Manager, Pricing, Tariff, and Power Cost Recovery

Portland General Electric Company
UE 452
PGE Response to OPUC Data Request 138
Dated May 27, 2025

Request:

Regarding PGE's potential summer capacity shortages (PGE/100 Outama-Pederson/19-20), was the shortage foreseen during the IRP/RFP process?

a. If so, what solutions were identified then?
b. If not, what factors and/or situations led to the shortage

Response:

Yes. PGE identified the shortage in the 2023 IRP process and actively sought to acquire resources to mitigate this shortage as part of the 2023 RFP. The 2023 RFP sought resources with commercial online dates between 12/31/2025 and 12/31/2027. In compliance with recommendation from the Independent Evaluator, PGE evaluated the bids presented within the RFP against market purchases for the purpose of evaluating the least-cost, least-risk options. PGE, in consultation with OPUC Staff and the Independent Evaluator, filed a final shortlist of resources in September 2024 that were identified through a fair, transparent process that was compliant with Oregon's competitive bidding rules. In Order No. 24-425, the OPUC acknowledged that the resources selected for the final shortlist were reasonable. Thus, PGE did seek resources to meet the 2026 FS capacity shortage, but ultimately selected the least-cost, least-risk resources in the RFP, consistent with Oregon rules. As described in PGE's response to OPUC Data Request No. 76, PGE has not included any 2023 RFP resources in the 2026 AUT.

CASE: UE 452
WITNESS: MADISON BOLTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 800

Redacted
Opening Testimony

June 23, 2025

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

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

Q. Please describe your educational background and work experience.

A. My Witness Qualifications Statement is found in Exhibit Staff/801.

Q. What is the purpose of your testimony?

A. I propose adjustments to the Company's Test Year Reliability Contingency Events (RCE) forecast and respond to the Company's strategy addressing capacity market constraints.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared Exhibit Staff/802, PGE Responses to OPUC Data Requests and Confidential Exhibit Staff/803, Confidential PGE Workpaper '1_2026 AUT Apr Filing Reliability Contingency Event Forecast'.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1. Capacity Market Constraints. 2
Issue 2. Reliability Contingency Events Forecast 8

ISSUE 1. CAPACITY MARKET CONSTRAINTS

Q. What is PGE's concern regarding capacity market constrains?

A. PGE testifies that variable resources, and the associated reduction in firm and dispatchable resources, is causing regional capacity shortages in the Western Electricity Coordinating Council (WECC) and the Western Power Pool (WPP) footprint.[1] This shortage limits the Company's ability to meet peak demand with market purchases during certain weather extremes, outages, transmission constraints, and other limiting events. During these events, market prices can see large increases driving scarcity pricing up to WECC's soft cap of $1000/MWh. These scarcity pricing events have become more common over the last decade.[2]

PGE is concerned about capacity deficits that could expose customers to scarcity pricing or reliability impacts during peak periods. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[3] The Western Resource Adequacy Program (WRAP)'s Forward Showing (FS) requirements aim to maintain sufficient regional capacity by requiring each member to demonstrate it has resources that match its peak load plus reserve margin over a seven-month period. The WRAP also administers a capacity sharing program where members who are short on capacity may call on members with excess capacity

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1 PGE/100, Outama – Pederson/16-19.
2 PGE/100, Outama – Pedersen/18.
3 PGE/100, Outama – Pedersen/19-20.

in a shortage event. Once the program is fully binding, WRAP members will have binding obligations to submit forward showings, and pay deficiency charges should they not remedy the capacity deficits in their forward showings. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Q. What strategies did PGE evaluate to address the capacity shortage and how would they be represented in MONET?

A. PGE identified two options:

1. Enter into capacity agreements to mitigate exposure to weather-induced demand spikes, reflected in MONET through a placeholder contract while PGE attempts to secure agreements. Once the capacity agreements are made, PGE would update MONET with the new contract(s).
2. Withhold a portion of a marginal resource from economic dispatch in MONET to ensure reliability during a capacity shortage. In MONET, the resource would be held back similarly to how planned outages are modeled.[4] The marginal resource is selected as it is the highest cost plant to generate in the Company's portfolio. If a different resource was held back, PGE would incur higher NVPC because the

[4] PGE/100, Outama – Pedersen/20-21.

difference between the market price and the plants operation costs would be greater than if the highest cost resource is selected.[5]

PGE chose the second strategy and will **[BEGIN CONFIDENTIAL]** [redacted][6] **[END CONFIDENTIAL]** Because this withholds the resource from being available to sell in the market, this strategy increases NVPC by $4.2 million.

Q. Does Staff have any concerns with this approach?

A. Yes. First, PGE only addresses the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Second, Staff questions whether withholding a marginal resource is an appropriate practice. Because of the uncertainty around whether PGE will be able to address the capacity deficit with new contracts that have a smaller impact on NVPC, and the opportunity for further clarity in power cost updates before the rate effective date, Staff feels it is premature to include this modeling approach in the forecast. Altering the modeling practices for existing resources is not a fair option to customers as it does not address the actual business risks that resource planning applies to customers. For example, if PGE experiences outages during 2026 while also raising NVPC by withholding

[5] PGE/100, Outama – Pedersen/20-21.
[6] PGE/100, Outama – Pedersen/21, 11-13.

capacity, customers would be paying additional power costs to address a capacity deficit while not even benefitting from a more reliable system. Because of this, Staff believes that the Company should not withhold a marginal resource in MONET as a planned outage, and the $4.2 million increase to NVPC should be disallowed.

Third, PGE has not modeled the NVPC impact of the first potential strategy to enter into capacity agreements.[7] Staff cannot verify whether PGE has selected the lowest cost option by withholding the marginal resource in MONET. While PGE notes that it will release the MWs it is withholding in the second strategy if the Company is able to secure contracts covering the capacity needs in 2026,[8] it is unclear to Staff whether this strategy would increase NVPC by less than the $4.2 million PGE projects. If PGE is able to secure contracts addressing the capacity needs at a lower cost and releases the MWs, these contracts could impact the $4.2 million forecasted increase related to withholding capacity.

If the Commission does not adopt Staff's recommendation to reduce NVPC by $4.2 million and model the deficit without withholding a marginal resource, Staff believes the impacts to PGE's dispatch (i.e., update to a planned outage) should be included in PGE's final updates to NVPC if the contracts are executed prior to November 6, 2025. Otherwise, Staff questions the appropriateness of including both the cost related to the reserved capacity

[7] Staff/802, Bolton/1, PGE Response to OPUC DR 66.
[8] PGE/100, Outama – Pedersen/21, 18-23.

and new contracts in the 2026 forecast. If new contracts are obtained before the effective date but are not included in the last November update, Staff recommends that a downward adjustment (capturing the costs of the new contracts) to PGE's actual NVPC be made in connection with the PCAM for the 2026 NVPC so PGE does not double-recover costs to cover the same capacity shortfall.

Fourth, Staff questions why the Company cannot model a capacity shortage as a load input in MONET, rather than implementing a planned outage on the generation side of the model. By Staff's understanding, a capacity shortage is at its core a problem of existing resources not being able to meet high load hours. By modeling the shortage as a load input, Staff assumes the model should dispatch generating resources to account for the capacity deficit on its own, without the Company simulating an outage to accomplish a similar result. If MONET is not capable of economically dispatching resources while factoring in capacity shortages, Staff questions whether an alternative modeling program is necessary, particularly with the increase in capacity shortage events over the last decade.

Q. What are Staff's recommendations to address the concerns discussed above?

A. Staff has three main recommendations, plus an alternative option should the Commission disagree with Staff's adjustment to NVPC:

1. PGE should explain its strategy to address the capacity deficit **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** and any NVPC impacts of this strategy.
2. If MONET is incapable of modeling capacity shortage events through load inputs, Staff recommends PGE begin transitioning to a different power cost model that can address the nuance of these kinds of scarcity events holistically and without intervening workarounds.
3. PGE should not subject customers to higher NVPC forecast by withholding a marginal resource via planned outage in MONET, and should decrease NVPC by $4.2 million. Or, if the Commission does not adopt this recommendation;

PGE should show any changes to its selected dispatch strategy (withholding a resource through a planned outage in MONET) in the final updates to NVPC if new contracts for capacity are executed prior to November 6, 2025. If the contracts are obtained after the final update and included in the NVPC forecast for 2026, Staff recommends that a downward adjustment (capturing the costs of the new contracts) to PGE's actual NVPC be made in the PCAM for the 2026 NVPC to prevent double recovery of costs.

ISSUE 2. RELIABILITY CONTINGENCY EVENTS FORECAST

Q. What are Reliability Contingency Events (RCEs)?

A. As Staff described above, PGE testifies that the region is experiencing more capacity constrained events due to a number of factors including extreme weather, transmission constraints, and variable generating resources. When these events meet certain criteria, cause major price spikes, and potentially threaten reliability, PGE defines them as an RCE. PGE asserts these price peaks are difficult to accurately model in MONET, so PGE separately forecasts RCEs and their impact to NVPC.

PGE declares an RCE when two of the following criteria are met:

- The day-ahead Mid-Columbia index prices must exceed $150/MWh.
- PGE is eligible to request or acquire resource adequacy (RA) assistance through a regional RA program in which it participates.
- A neighboring Balancing Area Authority (BAA) has declared an event that indicates impending or realized RA constraints.[9]

Q. How does PGE forecast RCEs?

A. PGE forecasts the average number of RCE days in a year using the number of actual RCEs from the previous three years. For these days, PGE then assumes the day-ahead forecasted wind generation is zero, the market is illiquid, and an additional amount of capacity reserve is needed for reliability. PGE reserves this capacity from its thermal generation. PGE uses these

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[9] UE 416, PGE/400, Sims – Outama/33-34.

assumptions to forecast a daily RCE cost by month. The total RCE forecast for 2026 is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].**[10]

Q. Does Staff have concerns with this forecast?

A. Yes. Staff previously raised concerns about removing the day-ahead wind generation in the RCE forecast in PGE's 2024 general rate case, Docket No. UE 416.[11] Staff found that day-ahead wind forecasts were reliable, and that PGE overestimates power costs by assuming no wind generation, especially since PGE could sell excess wind in the market. PGE claims that removing day-ahead wind is necessary because wind is a variable generating resource, meaning that the variation from forecasted generation could further exacerbate prices and reliability issues during an RCE. In UE 416, Staff found that wind generation was actually higher on average than forecasted and would help to lower NVPC if included in the RCE forecast.[12]

In UE 416, PGE agreed to re-evaluate the wind forecasts if changes were needed in future power cost dockets,[13] however, PGE has not proposed any changes to the RCE forecast and has continued to remove day-ahead wind generation. Staff remains concerned that this does not reflect prudent operations, and that the RCE forecast is improperly calculated to result in higher NVPC than necessary.

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[10] Staff/803, Bolton/1, Confidential PGE Workpaper '1_2026 AUT Apr Filing Reliability Contingency Event Forecast'.

[11] UE 416, Staff/300.

[12] UE 416, Staff/300, Dlouhy/24.

[13] *In the Matter of Portland General Electric Company, Request for a General Rate Revision; and 2024 Annual Power Cost Update,* UE 416, Third Partial Stipulation at 2, (July 11, 2023).

Not only is the forecast problematic, but so is the method of recovery. PGE is allowed to recover 80 percent of the RCE costs above forecasted outside of the deadbands in the PCAM pursuant to a previous stipulation and Commission order.[14] This practice is ordered to sunset in 2025.[15] Staff believes RCE costs should be subject to deadbands starting in 2026 given the concerns about removing wind generation and over-forecasted NVPC impacts.

Q. Did Staff estimate the RCE forecast if wind was not removed?

A. Yes. Staff determined that the RCE forecast would be reduced by 55 percent, for a total of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].**

Q. What are Staff's recommendations related to RCE forecasting and cost recovery?

A. RCEs most commonly take place during super-peak hours in the summer months.[16] As they are capacity constrained events, the RCE forecasts covering Q3 of 2026 would likely coincide with the capacity deficit in Summer 2026. If PGE carries out either method to address the capacity deficit previously discussed above,[17] then the RCE forecast is unnecessary because the needed capacity during an RCE will have already been procured. For this reason, Staff recommends removing the RCE forecast entirely, reducing NVPC by **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].**

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14 Order No. 23-386 at 11.
15 Id.
16 UE 416, Schwartz – Outama – Cristea/24, 1-9.
17 PGE identified two options: 1) Enter into capacity agreements to mitigate exposure to weather-induced demand spikes, reflected in MONET through a placeholder contract while PGE attempts to secure agreements. 2) Withhold a portion of a marginal resource from economic dispatch in MONET to ensure reliability during a capacity shortage. In MONET, the resource would be held back similarly to how planned outages are modeled.

Alternatively, if the Commission decides to not remove the RCE forecast in its entirety, Staff recommends that day-ahead wind generation be included in the RCE forecast, reducing the forecast to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** and reducing overall NVPC by **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].** While Staff recognizes that this issue is beyond the scope of this docket, Staff also recommends that in the PCAM, RCE costs should be fully subject to the deadbands.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 452
WITNESS: MADISON BOLTON

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 801

Witness Qualifications Statement

June 23, 2022

WITNESS QUALIFICATIONS STATEMENT

NAME: Madison Bolton

EMPLOYER: Public Utility Commission of Oregon

TITLE: Utility Analyst
Utility Strategy & Integration Division

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

EDUCATION: B.A. Carroll College, Helena, Montana
Major: Biology, 2017

M.ENV. University of Colorado, Boulder, Colorado
Specialization: Renewable and Sustainable Energy, 2020

EXPERIENCE: Since September 2021, I have been employed by the Oregon Public Utility Commission. I currently hold the position of Senior Energy and Policy Analyst in the Energy Program, where I've evaluated various large nonresidential consumer issues, utility voluntary renewable energy products, and direct access issues.

I have provided witness testimony in multiple general rate case and power cost dockets, including UE 399, UE 400, UE 402, UE 416, UE 420, UE 433, UE 434, UE 435, UG 433, UG 435, UG 519, and UG 520.

From 2019 to 2020 I worked as a graduate research analyst at E Source, where I conducted research for utility clientele on large non-residential energy consumers.

Additionally, in 2020 I assisted Camus Energy in researching the feasibility of electric grid management software.

CASE: UE 452
WITNESS: MADISON BOLTON

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 802

PGE Responses to OPUC Data Requests

June 23, 2022

May 30, 2025

To: Scott Gibbens
Oregon Public Utility Commission

From: Jaki Ferchland
Senior Manager, Pricing, Tariff, and Power Cost Recovery

Portland General Electric Company
UE 452 PGE Response to OPUC Data Request 066
Dated May 16, 2025

Request:

Please reference PGE/100 Outama – Pedersen/21, at 17. Does the Company anticipate that its first approach of entering into capacity agreements to maintain load serving reliability would cause a smaller increase in NVPC than $4.2 million?

Response:

PGE objects to this request on the basis that it requires significant new analysis and calls for speculation. Without waiving its objection, PGE responds as follows: PGE projected that the NVPC would increase by $4.2 million if PGE implements the proposed strategy outlined on PGE/100 Outama-Pedersen/21 lines 4 through 8. PGE did not model the alternative approach

CASE: UE 452
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PUBLIC UTILITY COMMISSION
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CONFIDENTIAL STAFF EXHIBIT 803

Confidential PGE Workpaper '1_2026 AUT Apr Filing Reliability Contingency Event Forecast'

June 23, 2022

CONFIDENTIAL STAFF EXHIBIT 803 IS PROVIDED IN ELECTRONIC FORMAT