Portland General Electric Company
121 SW Salmon Street • 1WTC0306 • Portland, Oregon 97204
portlandgeneral.com

June 21, 2023

Via Electronic Filing

Public Utility Commission of Oregon
Attention: Filing Center
P.O. Box 1088
Salem, OR 97308-1088

Re: **UE 416 – In the Matter of Portland General Electric Company, Request for a General Rate Revision**

Dear Filing Center:

Please find enclosed for filing in the above-captioned docket, Portland General Electric Company's Reply Testimony of Darrington Outama, Elizabeth Pedersen, and Stefan Cristea. A copy of the Confidential version of PGE's Reply Testimony is being sent as a password protected encrypted zip folder.

Thank you in advance for your assistance.

Sincerely,

Jaki Ferchland

Jaki Ferchland
Manager, Rates and Regulatory Affairs

JF/dm
Enclosure

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 416
Request for General Rate Revision

PORTLAND GENERAL ELECTRIC

Reply Testimony

Direct Testimony of:

Darrington Outama, PGE

Elizabeth Pedersen, PGE

Stefan Cristea, PGE

June 21, 2023

Table of Contents

I. Introduction

Q. Please state your names and positions with Portland General Electric (PGE).

A. My name is Elizabeth Pedersen. My position at PGE is Interim Manager, Power Cost Forecast. My qualifications appear at the end of this testimony.

My name is Darrington Outama. My position at PGE is Senior Director, Power Operations. My qualifications were previously provided in PGE Exhibit 300.

My name is Stefan Cristea. My position at PGE is Regulatory Consultant, Rates and Regulatory Affairs. My qualifications were previously provided in PGE Exhibit 300.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to respond to the positions of the Public Utility Commission of Oregon (OPUC or Commission) Staff (Staff), the Alliance of Western Energy Consumers (AWEC), and the Citizen's Utility Board of Oregon (CUB) put forward regarding PGE's net variable power cost (NVPC) forecast for 2024.

Q. Did Parties reach a partial settlement during the June 14, 2023 settlement conference?

A. Yes. As part of the settlement conference, participating parties reached agreement in principle on the following issues:

- BPA Wheeling:
  - 2023 AUT Stipulation: BPA RDC
  - 2023 AUT Stipulation: BP-24 Rates
  - BPA 2024 Transmission Rates
- Delivered Gas
- Carty Forced Outage Rate
- Biglow Capacity Factor

- California-Oregon Border Trading Margin

Stipulating Parties will submit a Partial Stipulation and Joint testimony in Support of the stipulation describing the agreed settlement on these issues.

Q. Please summarize your review of parties' positions on the remaining issues.

A. Parties have introduced positions on numerous issues, with a consolidated recommended reduction of approximately $146.5 million[1] to PGE's 2024 NVPC forecast for the remaining issues. This reduction is both exorbitant and unrealistic. As described in more detail below, PGE finds parties' recommendations for the remaining items to be: (1) inaccurate, (2) opportunistic in seeking benefits (without recognizing costs or risks), (3) not supported by reasonable assumptions, and/or (4) based on incomplete or erroneous analysis. If implemented in their entirety, these recommendations and associated reductions would unfairly introduce a significant downward bias on PGE's NVPC forecast, making it highly unlikely that PGE would recover its prudently incurred power costs in 2024 under the construct of the current PCAM.

Q. What is your recommendation regarding the specific issues identified below?

A. We recommend the Commission reject AWEC's, OPUC Staff's, and CUB's proposed adjustments and recommendations for the remaining items.

Q. Does OPUC Staff have an overarching recommendation regarding PGE's NVPC forecast?

A. Yes. Staff identified a number of shortcomings associated with PGE's MONET model that we use to forecast NVPC and state that "switching from MONET to a different model may

[1] AWEC classified the individual adjustments as confidential information in AWEC Exhibit 100. PGE does not consider this information to be confidential and, in agreement with AWEC, we will include it as public information in this reply testimony.

lead to greater consistency between planning and implementation, fewer calculations done outside of the model, and greater accuracy for power cost forecasts, given the granularity of other models."[2]

Q. Is PGE investigating alternative models to forecast NVPC?

A. Yes. As provided in PGE's response to OPUC Data Request No. 530, PGE is considering options to enhance the modeling of the NVPC forecast, including new software or methods other than MONET.

Q. What specific issues do you address in your testimony?

A. We address the following issues raised by parties:

- Flexibility Down Reserves (Section II-A)
- Washington Climate Commitment Act (Section II-B)
  - Washington Climate Commitment Act Allowance (CCA) Costs
  - Specified Source, Non-Emitting Sales
- Thermal Parameters (Section II-C)
  - EIM Master File Parameters
  - Beaver Cycling
- Reliability Contingency Events (Section II-D)
- Physical Gas Call Option (Section II-E)
- Other Items (Section II-F)
  - Schedule 125 Changes
  - Balancing Impacts

[2] Staff/100, Jent/17 at 3-6

Q. How is the remainder of your testimony organized?

A. After this introduction, we have four sections:

- Section II: Parties' Proposed Adjustments
- Section III: Summary
- Section IV: Qualifications

II. Parties' Proposed Adjustments

A. Flexibility Down Reserves

Q. Please summarize AWEC's recommendation with regards to flexibility down reserves?

A. AWEC recommends that flexibility down reserves be allocated to PGE's thermal resources at no cost prior to being allocated to hydro resources. AWEC models their recommendation by removing all flexibility down reserves in MONET, which results in a $48.6 million reduction to the 2024 NVPC forecast.

Q. What are AWEC's arguments in support of this recommendation?

A. AWEC states that PGE's reserves modeling results in dispatching hydro during uneconomic hours and also includes an assumption that PGE will voluntarily spill a large volume of hydro energy, which is not consistent with how PGE operates its system, nor is it prudent. AWEC also asserts that the principal cause of this inefficient hydro dispatch is the treatment of downward flexibility reserves, which are being incorrectly allocated entirely to hydro resources without considering the downward reserves available at no cost from thermal resources. AWEC claims that an adjustment that allocates downward flexibility reserves to thermal resources prior to allocation to hydro resources results in a more efficient hydro dispatch and a more accurate forecast of PGE's cost of reserves.[3]

Q. Do you agree with AWEC's recommendation?

A. No. AWEC's calculation of the adjustment is not reasonable because it contains errors and is incomplete. When corrected, AWEC's proposal results in a minimal impact to the 2024 NVPC forecast.

[3] AWEC/100, Mullins/ 4 at 6.

Q. You state that AWEC's proposal is not reasonable. Please explain.

A. Based on an incorrect assumption that thermal generation can provide zero cost downward reserves, AWEC states that PGE didn't consider downward reserve requirements in MONET prior to the 2023 AUT.[4] This is not correct. Contrary to AWEC's assertion, PGE's NVPC forecast calculation included symmetrical upward and downward flexibility reserve modeling since at least the 2014 GRC in UE 262. Because the symmetrical reserves modeling conventions were consistently applied since 2014, a way to assess the reasonableness of the $48.6 million resulting changes proposed by AWEC is to look at historical actual results of PGE's PCAM filing compared to the relevant AUT filing: a simple review of PGE's PCAM results makes it obvious that AWEC's adjustment is not warranted because there was no year in which PGE would over-forecast by this magnitude. In fact, just looking at the last two years, PGE's actual NVPC was significantly above the forecast, by a combined approximate $86 million.

Q. You mention that AWEC's modeling contains errors. Please identify these errors.

A. In addition to their apparent misunderstanding of when PGE first introduced downward flexibility reserves in the AUT, AWEC's modeling change is mechanically incorrect, and results in extremely skewed results. When applying their modeling change, AWEC zeroed out the column labeled "Uncertainty Down" and left "Uncertainty Up" as is. However, AWEC was likely not aware that the code inside the MONET model uses "Uncertainty Down" as the number for both Up and Down reserves. Thus, by removing the flexibility down reserves, AWEC also inadvertently removed all flexibility up reserves (i.e., Day-Ahead Forecast Error

---

[4] AWEC/100,Mullins/6 at 22.

or DAFE and Hour Ahead Forecast Error or HAFE reserves) as well, which resulted in a grossly overstated impact of their proposal.

Q. Could AWEC have discovered this unintended modeling result?

A. Yes. The model produces a result report called "MidC Ancillary Service Reports." To verify their proposed modeling, AWEC could have reviewed this report and observed that both "MidC RM up dispatch" (i.e., up reserve requirement) and "MidC RM down dispatch" (i.e., down reserve requirement) were zero as opposed to the intended results whereby only "MidC RM down dispatch" would show zero.

Q. You state above that AWEC's analysis is incomplete, please explain?

A. AWEC's analysis is incomplete because they did not perform all necessary steps to ensure that their proposal is modeled accurately. Specifically, in order to correctly effectuate AWEC's proposed "Up reserves" only approach, AWEC should have addressed the following:

1. symmetrical nature of the up and down reserves requirement in the Ancillary Services module; and
2. the portfolio impact of allocating the down reserves to thermal resources.

Q. Has PGE corrected AWEC's analysis?

A. Yes.

Q. What is the NVPC reduction if AWEC's recommendation is applied correctly?

A. After correcting the errors and completing all necessary steps in MONET to implement AWEC's proposed approach, the 2024 NVPC forecast impact is a minor reduction of $0.253 million compared to AWEC's unrealistic reduction of $48.6 million. PGE is providing a detailed description of the analysis performed in PGE Exhibit 1501 and supporting workpapers.

Q. Does PGE propose to model DAFE/HAFE reserves as described in PGE Exhibit 1501.

A. Not at this time. PGE will investigate the reserves method described in Exhibit 1501 further to ensure appropriate modeling of ancillary services. Based on the findings of PGE's investigation, PGE intends to propose a regulating reserve modeling in either the next general rate case or, should the Commission adopt our proposed changes to Schedule 125 guidelines, the next AUT.

Q. Does AWEC raise other concerns regarding flexibility down reserves modeling?

A. Yes. AWEC also provides that "the downward flexibility reserves included in the MONET model is overstated"[5] relative to actual EIM flexibility reserve requirement. Consequently, AWEC "adjusted the downward reserve requirements to be consistent with the amounts historically calculated by the EIM."[6]

Q. Is AWEC's adjustment appropriate?

A. No. AWEC based this adjustment on data provided by PGE in response to AWEC Data Request No. 096. Specifically, PGE provided the upwards and downwards flexible ramping reserves requirements (i.e., Uncertainty Requirements) for each available EIM time interval over the period January 1, 2020 through December 31, 2022. However, the flexible ramping reserves requirements in the EIM does not align with the flexibility reserves modeled in MONET because they address different timeframes.

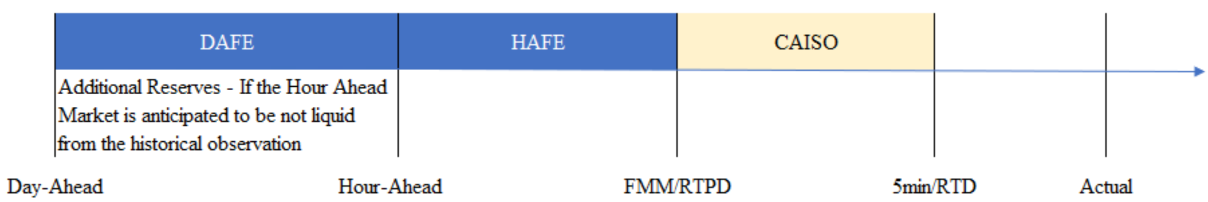
Q. Please elaborate.

---

[5] AWEC/100, Mullins/11 at 11-12
[6] AWEC/100, Mullins/12 at 1-2

A. The uncertainty component currently used in the flexible ramping sufficiency test in EIM is calculated from the historical forecast error observation, which is the difference between forecasts in the 5-minute market and the forecast in the 15-minute market. In comparison, the DAFE/HAFE flexibility reserve requirements in the MONET ancillary service modeling accounts for forecast errors from day-ahead to hour-ahead, forecast changes for hour-to-hour, and forecast errors within the hour. Therefore, in general, the EIM flexible ramping reserve requirement is less than the flexibility reserve requirement modeled in PGE's ancillary services model. Figure 1 below depicts the different timeframes contemplated by EIM flexibility requirements and flexibility reserves held in MONET.

Figure 1: Flexibility Reserves Time Frames MONET vs CAISO EIM



Q. In conclusion, is PGE overstating the flexibility reserve needs modeled in MONET, as AWEC is asserting?

A. No. CAISO's flexibility reserve requirement in the EIM is only covering the intra-hour uncertainty whereas in actual operations PGE must manage the forecast changes from day-ahead to hour-ahead, forecast changes for hour-to-hour, and within the hour.

Q. AWEC has also noted that the uncertainty requirement can be offset by the diversity benefit. Is this correct?

A. No. Within EIM, both up and down uncertainty requirement for a given 15-min interval in the next hour is calculated without diversity benefit because EIM requires that each participating Balancing Authority can stand on their own before benefiting from the diversity. The diversity benefit will be "unlocked" only when an EIM entity has passed EIM resource Flexible Ramping Sufficiency Test and EIM Capacity Test (see CAISO Energy Imbalance Market BPM section 11.3.2 for more details).

Q. Please summarize your position on AWEC's recommendation and arguments regarding flexibility down reserves.

A. PGE fundamentally disagrees with AWEC's recommendation. AWEC's analysis in support of their recommendation is materially flawed and is contrary to market rules, resulting in a massively inflated and unrealistic power cost adjustment that cannot be achieved in actual operations, which is evident given PGE's historical PCAM results. Therefore, the Commission should reject AWEC's proposal regarding flexibility down reserves.

B. Washington Climate Commitment Act

1. Washington CCA Allowance Costs

Q. What parties' provided discussion with respect to Washington CCA Allowance costs?

A. AWEC and Staff addressed this issue in their opening testimonies.

Q. What is AWEC's recommendation with respect to Washington CCA Allowance costs?

A. AWEC recommends that power costs associated with carbon obligations under the Washington CCA be removed from the 2024 NVPC forecast. Additionally, AWEC argues that PGE should adjust Mid-C index prices modeled in MONET "downwards to reflect the lower cost for purchasing power that is delivered outside of Washington State and not subject to the CCA."[7]

Q. Did Staff provide a recommendation?

---

[7] AWEC/100, Mullins/12-13, at 20-1

A. No, at least not a final recommendation. Staff discussed this issue but did not provide a final recommendation. Instead, Staff stated that, due to the uncertainty around Washington CCA compliance costs, they are considering recommending that "CCA compliance costs not be subject to the PCAM deadband and sharing."[8] However, Staff continues to investigate "the forecasted price of compliance and the forecast of energy subject to compliance requirement" and "may have recommendations on these forecasts in their Response Testimony."[9]

Q. Do you agree with Staff's consideration that CCA compliance costs not be subject to the PCAM deadband and sharing?

A. We agree in principle with Staff's consideration. As PGE previously described in PGE Exhibit 400, the existing PCAM structure no longer reflects the realities of the current and expected power cost environment. The Washington CCA is yet another element that makes power market conditions increasingly unpredictable, and adds uncertainty and power cost forecast risk, warranting PCAM reform.

Q. Do you agree with AWEC's recommendation?

A. No. AWEC's proposed adjustment is based on incorrect calculations that grossly overestimate the reduction applied to PGE's 2024 NVPC forecast and it is also based on the flawed and over-simplified assumptions that AWEC argues PGE is guilty of.

Q. What is AWEC's argument with respect to how the Mid-C index price will be impacted by the Washington Cap and Invest program?

A. AWEC argues that the implementation of the Washington Cap and Invest program will impact the Mid-C market prices such that Non-Washington Sink (i.e., non-WA sink) power products

---

[8] Staff/200, Ahmed/9 at 20-21
[9] Staff/200, Ahmed/8-9 at 20-1

will be transacted at a deeply discounted Mid-C price. Additionally, AWEC argues that market sales of Washington CCA Compliant products will "demand higher prices relative to the Non-Washington Sink index prices" and "the additional revenues from those sales will directly offset the cost of purchasing allowances."[10]

Q. What discount does AWEC apply to Mid-C prices for non-WA Sink products

A. AWEC assumes the discount will be $21.19/MWH, which is based on a Washington carbon allowance auction price and the unspecified emission factor for Mid-C market transactions. Therefore, AWEC provides that "all power PGE exports from Mid-C will come at a discount relative to the Mid-C index price."[11]

Q. What is AWEC's proposed power cost adjustment?

A. Based on the assumptions described above, AWEC "reran the MONET model assuming that Mid-C market prices were $21.19/MWh lower than the Washington CCA Compliant market index prices PGE had assumed. This resulted in a $32,832,450 reduction to NVPC."[12] In addition to adjusting the Mid-C index prices, AWEC recommends removing PGE's estimated costs associated with the Washington Cap and Invest, resulting in a total adjustment of approximately $48.6 million.

Q. Did AWEC model the discounted Mid-C index prices correctly?

A. No. AWEC incorrectly adjusted the Mid-C index prices that are applied to PGE's long-term hydro contracts and did not adjust the Mid-C prices within the Lydia model that are used to price market purchases and sales. Therefore, the modeling performed by AWEC inappropriately changed the Mid-C index prices stipulated in the terms of PGE's long-term

---

[10] AWEC/100, Mullins/17, at 16-19
[11] AWEC/100, Mullins/16, at 20-21
[12] AWEC/100, Mullins/17, at 12-13

hydro contracts (there are no such contract re-opener that allows PGE to do so) while the Mid-C prices applied to other market purchases and sales remained unchanged. Correcting AWEC's analysis to apply Mid-C price adjustments to the Lydia model and apply the reduced price to market purchases and sales reduces their proposed adjustment from the total of $48.6 million to only $3.3 million.[13]

Q. Aside from the calculation errors, does PGE agree with AWEC's proposed discount to Mid-C index prices?

A. No. AWEC oversimplifies its modeling of carbon obligation costs for the Washington CCA. AWEC assumes that non-Washington Sink power will transact at a discount that is Mid-C index minus the estimated cost of a carbon allowance. In practice, PGE is observing non-WA sink prices that are considerably closer to the Mid-C index. Year to date (i.e., through May 2023), PGE has transacted at volume-weighted average discounts of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for market purchases and **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for market sales for non-WA Sink products. These market-based results are in stark contrast to AWEC's proposed $21.19/MWh discount.

Q. AWEC also supports their recommendation on the assumption that all PGE sales at Mid-C will be either non-WA Sink, with no compliance obligation, or CCA compliant, at a price premium relative to the non-WA Sink product price that directly offsets the carbon compliance costs. Is this a reasonable assumption?

[13] See workpaper named "WA CCA - 2024GRC-040 AWEC Corrected with Lydia Reduced"

A. No. To-date the market for Non-WA Sink products at Mid-C has demonstrated limited liquidity. That is, actual market observations reflect days when non-WA sink products have neither an offer (i.e., party willing to sell) nor a bid (i.e., party willing to buy) in the bilateral market. Therefore, it is not reasonable to simply assume that all PGE sales at Mid-C will be or can be for Non-WA Sink products. Moreover, the price discount for non-WA sink will vary based on market supply and demand. As noted earlier in our testimony, in practice Mid-C prices are not trading at premiums to non-WA sink products equivalent to the cost of an allowance. Therefore, it is not appropriate nor reasonable to assume that PGE will realize a net benefit from WA CCA transactions.

Q. What is the power cost result from an assumed set of non-WA sink prices and how does the result compare to the results from PGE's current methodology for forecasting a NVPC impact from the Washington Climate Commitment Act?

A. In a scenario where PGE assumes market sales and purchases in the MONET model are priced at minus $1.50 in Q1, Q2 and Q4, but minus $21.19 in Q3, PGE would forecast a cost increase of $13.6 million, which is very close to the $15.8 million cost increase under PGE's current methodology.

Q. Why would minus $21.19/MWh be a reasonable assumption in the third quarter (Q3) of the test year?

A. While PGE's volume weighted price results currently demonstrate a small discount in the non-WA sink product, PGE has sold non-WA sink at discounts as low as **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** during the first five months of 2023. Additionally, PGE is incentivized to sell non-WA sink at discounts as low as the equivalent cost of a carbon allowance (e.g., assumed to be $21.19/MWh in PGE's March 31, 2023 MONET Update filing) before selling power as the Mid-C standard product and incurring a carbon obligation.

As we described in our initial testimony, the cost risk associated with the impacts from the Washington Cap-and-Invest program is most prominent during summer months when MONET's deterministic economic logic dispatches PGE's marginal peaking resources, Beaver and PW2, for energy at their maximum capacity for the majority of June through September and monetizes any generation length through wholesale market sales. Therefore, if PGE revised its modeling methods to be based on a non-WA sink product (instead of carbon allowance purchases) it is not unreasonable to assume the cost risk PGE is exposed to in the modeled third quarter of the test year is equivalent to market sales priced at a non-WA sink price as low as the equivalent cost of carbon for selling a standard product with a WA sink.

Q. Are there any other developments associated with the Washington Climate Commitment Act that may impact actual NVPC for PGE?

A. Possibly yes. On March 1, 2023, PGE and other entities sent a letter to the Washington Department of Ecology identifying omissions in the rules that create increased uncertainty around the Washington Climate Commitment Act. Specifically, the letter identified the following omissions in the rules:

- Electricity Imports to sink Points of Delivery (i.e., PODs) in other multistate BAAs (e.g., PGE's Mid-C sink).
- Electricity imports to discrete Washington loads within Balancing Authority Areas other than BPA.
- Electricity import points upstream of designated scheduling points of BPA Washington customers.

- Balancing energy provided by multistate Balancing Authorities for Washington resources

On May 24, 2023, the Washington Department of Ecology affirmed via letter that it will accept emissions reports that rely on the proposals set forth in the letter and paper submitted by entities on March 1, 2023.

Q. Which of the rule omissions listed above could most impact the WA Cap and Invest cost PGE incurs in actual NVPC?

A. The first item is likely to be the most impactful of the four, but it is limited to purchases. Specifically, since PGE's Mid-C sink will be treated as a non-Washington sink, PGE can wheel power through Mid-C without incurring a carbon obligation. The letter from Washington Department of Ecology also provides clarity to market participants that PGE's Mid-C sink is non-Washington (i.e., sellers to PGE would not need to assume they incur a carbon obligation if selling to PGE at PGE's Mid-C sink).

Q. Does guidance from the Washington Department of Ecology reduce the risk of incurring an obligation associated with market sales, including sales,[14] associated with summer months when the MONET model monetizes length from PGE's peaking resources through wholesale sales?

A. No. In instances where PGE would need to import electricity into Washington to meet modeled sales levels the source would likely be unspecified, because the source would not be known prior to time of entry into the transaction (i.e., the source would come from PGE's

[14] See PGE's Exhibit 300, Section III.B, pages 17-18, lines 10 – 3 and Section III.C, page 30, lines 7-14 for a detailed description of this risk.

portfolio). In these instances, PGE's sales would carry the unspecified emission factor of 0.437 metric tons of CO2 equivalent per MWh and the associated carbon obligation cost.

Q. Please summarize your position on AWEC's recommendation regarding Washington Climate Commitment Act compliance costs.

A. PGE does not agree with AWEC's recommendation because AWEC's proposed adjustment is based on incorrect calculations that grossly overestimate the reduction applied to the 2024 NVPC forecast. AWEC's recommendation is also based on the flawed and over-simplified assumptions specific to non-WA sink prices observed in the marketplace. Notwithstanding AWEC's proposed adjustment, alternative methods to adjust PGE's net variable power cost forecast to account for the impacts from the Washington Climate Commitment Act yield power cost impacts similar in result to the power cost increase proposed by PGE. Therefore, PGE recommends no changes to its proposed method.

2. Specified Source, Non-Emitting Sales

Q. Please summarize AWEC's recommendation regarding specified source, non-emitting energy power sales under the Washington CCA.

A. AWEC recommends an adjustment to PGE's forecast associated with modeling potential specified source, non-emitting energy sales at a premium under the Washington CCA based on the argument that the "CCA is an economic opportunity for PGE to sell specified source, zero carbon power at a premium in the Mid-C market."[15]

[15] AWEC/100, Mullins/18 at 3-5

Q. How does AWEC reflect the adjustment in the 2024 NVPC forecast modeling?

A. AWEC assumes that 50% of all market sales modeled in MONET will be deliveries of specified source, non-emitting energy under the Washington CCA at a $21.19/MWh premium. Their assumption results in a $7.9 million reduction to PGE's forecast.

Q. Did AWEC provide any analysis in support of their assumption that 50% of market sales modeled in MONET will be deliveries of specified source, non-emitting energy under the Washington CCA?

A. No. AWEC provided no analysis in support of their 50% assumption. AWEC simply states that their recommendation "to assume that half of the sales PGE makes in the Mid-C market are for specified source, non-emitting power" because of the recognition that "the opportunity for such sales may only represent a portion of the sales PGE makes."[16]

Q. In practice do complexities exist with implementing AWEC's recommendation(s) for specified source sales?

A. Yes. Contrary to the oversimplification in AWEC's recommendation that 50% of market sales at Mid-C would be specified source, non-emitting energy, there are meaningful complexities associated with establishing power contracts for specified source sales from non-emitting resources (e.g., hydro or wind) that inherently have volumetric uncertainty. A notable case is managing volumetric uncertainty paired with the time periods and durations associated with standard product trading. For example, in day ahead trading, PGE most often trades products that require deliveries of consistent hourly volumes over time periods of 8, 16, or 24 hours depending on the product. Under standard day ahead trading, PGE must have the confidence that specified deliveries from non-emitting resources (e.g., hydro or wind) can meet the sales

[16] AWEC/100, Mullins/18 at 23-24

volume over every hour of the delivery period (e.g., 8, 16, or 24). For standard term trading, it would be even more impracticable to assume on a forecast basis that PGE could meet a delivery requirement from a non-emitting resource for, not only the time periods we identify in our day ahead trading example, but also for an extended duration (e.g., term trading often trades in durations of months, not days).

Q. What is the consequence if PGE would not meet the energy delivery commitment stipulated in the contract?

A. PGE would first seek to meet the contractual obligation with unspecified source generation that would carry a carbon compliance obligation. Additionally, PGE would be at risk of incurring liquidated damage costs if in more extreme cases it could not find any source at all to keep the sale firm to the counterparty. AWEC does not account for these risks in their proposal.

Q. Does PGE have to identify the specified source(s) at the time a transaction for sale of specified source, non-emitting energy is executed?

A. Yes. Any specified source, non-emitting energy sale transaction must identify in its contract the resources that are the specified source(s). Therefore, it is not appropriate to assume market sales in MONET, which are forecast as real-time hourly transactions to balance the system's demand and supply, can be monetized as specified source, non-emitting energy deliveries.

Q. Has PGE executed any Washington specified source, non-emitting energy sale contracts year to date?

A. No, PGE has not executed any such contract for deliveries in year 2023 or year 2024.

Q. Does PGE's Schedule 125 guidelines provide for a process regarding the additions of power sale and purchase contracts?

A. Yes. Should PGE execute a power sale or purchase contract, the deadline for inclusion in the NVPC forecast is the first November MONET Update. For a 2024 NVPC forecast contract, this deadline is the November 7, 2023 MONET Update. Therefore, if PGE executes any specified source, non-emitting energy sales contracts before the November 7, 2023 MONET update, PGE will include the associated benefits in the 2024 NVPC forecast.

Q. Is AWEC's proposal in conflict with other positions they take in testimony?

A. Yes.

Q. Please explain.

A. AWEC opposes the inclusion of placeholder contracts and provides elsewhere in their testimony that "PGE is only allowed to include executed contracts in the AUT."[17] However, AWEC is opportunistic in seeking benefits and proposes, consciously or not, the exact opposite of what their position is regarding proxy or placeholder contracts. That is, AWEC argues for the inclusion of placeholder contracts for specified source, non-emitting energy.

Q. Please summarize your position on AWEC's recommendation regarding specified source, non-emitting energy deliveries at the Mid-C market.

A. PGE does not agree with AWEC's recommendation because it is based on an unsupported assumption regarding the amount of market sales that PGE could potentially execute from specified source, non-emitting energy and it also ignores the AUT process that is already in place for including power contracts in the NVPC modeling.

---

[17] AWEC/100, Mullins/21 at 6-7

C. Thermal Parameters

1. EIM Master File Parameters

Q. Please summarize AWEC's recommendation?

A. Following their review of PGE's thermal plant parameter reported to the EIM, AWEC identifies that plant capacities reported to EIM are higher than the thermal plant capacities used for NVPC forecast modeling in MONET. Based on this, AWEC recommends PGE use the plant capacities reported to EIM for NVPC forecast modeling, which results in a $26.5 million reduction to forecast power costs.

Q. Do you agree with AWEC's recommendation?

A. No. AWEC's recommendation is unreasonable and opportunistic, as it uses plant parameters which can only be achieved under optimal ambient conditions, as opposed to operating parameters more reflective of normal operating conditions.

Q. Why are the plant capacities reported to EIM different than the plant capacities modeled in MONET?

A. The plant parameters reported to EIM represent *maximum* potential capacities for PGE's thermal plants, which can be achieved only given certain ambient conditions and operating configurations. For example, the maximum potential plant capacities include emergency operating situations such as running the unit in overpressure. In actual operations, any updates to the ambient conditions both for the real time and forward-looking timeframes are promptly communicated to EIM through the CAISO outage system to ensure the thermal available capacity will be accurately represented in the EIM. The plant parameters reported to EIM are intended to include the entire operating range for a resource and the maximum potential capacity will only act as a capacity value in the market (1) under the unique conditions we described above or (2) if CAISO fails to process an outage or ambient related de-rate in its market software.

Q. Please summarize your position regarding AWEC's recommendation regarding the EIM master file parameters?

A. PGE does not find this recommendation to be appropriate because thermal capacities reported to EIM are not meant to be representative of expected average ambient conditions nor do they accurately reflect normal operating plant configurations.

2. Beaver Cycling

Q. Please summarize AWEC's recommendation.

A. AWEC argues that Beaver dispatch patterns in the MONET model do not correspond with how the plant has historically been dispatched. Based on this finding, AWEC recommends that PGE model Beaver dispatch based on historical dispatch patterns. Their recommendation results in a $8.8 million reduction to the 2024 NVPC forecast.

Q. Do you agree with AWEC's recommendation?

A. No. AWEC's recommendation ignores and circumvents the gas storage optimization modeling for the PW/Beaver complex and overwrites the run hour constraints built into the model. The Beaver dispatch in MONET needs to be evaluated within the context of the gas storage optimization modeling, which AWEC fails to do. Additionally, AWEC's calculation to support their proposed Beaver dispatch pattern is neither reasonable in that it uses an unsupported 90th percentile cycling length, nor is it performed correctly. We will discuss the merit of AWEC's calculation below in this section.

Q. Please explain how Beaver dispatch is tied to the gas storage optimization model.

A. In the gas storage optimization modeling, constraints are placed on the Beaver dispatch due to availability of gas for plant operation. AWEC Exhibit 105 references the "PGE Modeled Max Run Time". Those run hour limits are determined in the gas storage optimization modeling and reflect fuel availability for Beaver dispatch following the fuel allocation optimized for PW1/PW2 and considers N. Mist stored gas injections, gas withdrawals, and maintenance derations, which affect the fuel supply. The 'Gas Storage' worksheet in MONET provides the total fuel supply available to the PW/Beaver complex and calculates the fuel allocations for each plant by matching plant fuel demand to fuel supply, thus ensuring that any constraints for Beaver dispatch are aligned to fuel availability. Therefore, simply adjusting the Beaver cycling with disregard to fuel supply available from the gas storage optimization model is not appropriate.

Q. Is it reasonable to use historical averages to inform the cycling of the Beaver plant?

A. No. In any given year, the operation of the Beaver plant will differ from the model operation as PGE responds to the need for Beaver Generation to support meeting load. Relying on historical cycling operations does not incorporate these considerations. Additionally, AWEC's analysis uses years 2021 and 2022 that included major heat events and market disruptions that impacted Beaver generation and cycling, resulting in almost double the energy generation at Beaver compared to years 2019 and 2020.

Q. Does AWEC's proposal account for the most recently known information regarding expected market environment, fuel availability, and plant performance parameters?

A. No. AWEC's recommendation ignores any such information.

Q. Did you review AWEC's approach to determine historical dispatch patterns at Beaver that supported their recommendation?

A. Yes. PGE reviewed and does not agree with the method used by AWEC to determine their proposed Beaver dispatch pattern.

Q. Please elaborate.

A. AWEC Exhibit 105 incorrectly determines the Beaver cycling run time using the historical generation values during the hour in which the plant was started, rather than the number of hours the plant ran before shutting down to cycle. AWEC Exhibit 105 provides a summary table of those generation values by percentile (mislabeled as "Actual Run Time by Percentile"), and AWEC arbitrarily adjusts the 90th percentile by unsupported values for start-up and shut-down time across the year to propose new cycling limits for Beaver dispatch. Finally, AWEC then ignores those proposed cycling limits and instead modifies Beaver's parameters for run hour limits in MONET to reset them to 100 run hours for all months. This approach overwrites the run hours built into the model to reflect the gas storage optimization considerations discussed above and results in ignoring the constraints aligning plant fuel demand with available fuel supply.

Q. AWEC applies a 90th percentile to the historical dispatch pattern they identify to determine the Beaver cycling length that supports their proposed adjustment. What is PGE's position on this approach?

A. PGE does not find this approach reasonable. Aside from the fact that it is using incorrect values from the historical data as discussed above and it is not supported by any analysis, there is no reasoning for why a 90th percentile is the appropriate cycling limit to historical dispatch patterns when the MONET environment considers average conditions. AWEC is once again opportunistic arguing that average conditions should be applied for certain proposed adjustments (i.e., RCE, gas call option) while using and arguing for non-average conditions and assumptions for other adjustments (i.e., Beaver cycling, thermal capacities).

Q. Please summarize your position on AWEC's recommendation regarding the Beaver cycling?

A. PGE does not agree with AWEC's recommendation. As described in this testimony, AWEC's recommendation is opportunistic in seeking benefits, based on incorrect analysis, and it fails to evaluate the Beaver dispatch in the context of the gas storage optimization model. Therefore, the Commission should reject AWEC's proposal regarding Beaver cycling.

D. Reliability Contingency Events

Q. Which parties raised concerns regarding PGE's proposed modeling regarding Reliability Contingency Events (RCE)?

A. Both OPUC Staff and AWEC raised concerns and provided recommendations regarding the RCE modeling.

Q. Please summarize AWEC's recommendation regarding the RCE modeling included in PGE's 2024 NVPC forecast.

A. In summary, AWEC argues that the "AUT is based on a deterministic forecast of median, or normal conditions"[18] and including RCE expected costs in the forecast is one-sided because the NVPC forecast does not include benefits related to favorable conditions. Additionally, AWEC argues that PGE's calculations in support of RCE amounts are flawed because the modeling does not use or consider contingency reserves already included in the reserve

[18] AWEC/100, Mullins/26, at 21-22

forecast. Therefore, AWEC recommends excluding the amount associated with RCEs from the 2024 NVPC forecast.

Q. Please summarize your position regarding AWEC's recommendation?

A. PGE does not agree with AWEC's recommendation. AWEC is basing their recommendation on incorrect assumptions regarding the use of contingency reserves and does not recognize that forward price curves in MONET account for hours when market prices are exceptionally low. Additionally, AWEC is opportunistic in seeking benefits and inconsistent in their proposed adjustments. On the one hand, AWEC proposes reductions to the NVPC forecast based on modeling that considers non-average conditions (i.e., Beaver cycling, thermal capacities) but also argues that RCE should be excluded because the AUT is based on average conditions.

Q. Please provide an overview of PGE's RCE proposal.

A. PGE's proposed RCE forecast, designed within the PCAM and AUT frameworks, is meant to operate as a true-up mechanism for events that put load serving reliability at risk due to load excursion, regional market illiquidity, or price excursion. During these events, power supply planning and operations may deviate from normal operations that rely on economics and optimize market opportunity to meet customer load reliably and at the lowest cost. As part of the true-up, any variance between the RCE forecast and actual costs incurred will be fully refunded/collected from customers.

Q. Please discuss AWEC's argument that PGE's RCE calculations are flawed because contingency reserves were not considered.

A. AWEC's argument is incorrect. As previously described in PGE Exhibit 300, PGE elects to declare an RCE to mitigate the risk of the Reliability Coordinator (RC)-West issuing an

Energy Emergency Alerts (EEA) for PGE's Balancing Area Authority (BAA). WECC RCs declare EEAs when there is reliability risk due to a regional capacity shortage and market scarcity event often paired with runaway market price risk.[19] PGE needs to maintain contingency reserves at all times, including during both RCEs and EEAs.

Q. Why is PGE prevented from using contingency reserves during RCEs or EEAs?

A. Generally speaking, reserves are used in a region wide coordinated way to respond to energy events like generation forced outages or equipment outages. During loss of energy supply, contingency reserves are deployed to fill the gap in energy needed from the loss (and restore the frequency back to its nominal level). Contingency reserves are part of regular operations to keep the system in balance between supply and demand. Therefore, PGE is required to maintain minimum contingency reserves for reliability purposes at all times. PGE cannot simply dispatch contingency reserves to "produce power in lieu of purchasing high priced power"[20] as AWEC argues. Doing so would be in violation of NERC Reliability Standards.

Q. Please describe the EEA levels and how contingency reserves are accounted for?

A. To ensure that all Reliability Coordinators clearly understand potential and actual Energy Emergencies in the Interconnection, North American Electric Reliability Corporation (NERC) has established three levels of EEA, which is an emergency procedure:

- EEA 1: All available generation resources in use:

[19] *See* NERC EOP-011-1 at: https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-011-1.pdf . Reliability Coordinator may declare whatever alert is necessary and need not proceed through the alerts sequentially.
[20] AWEC/100, Mullins/27 at 20-21.

- EEA 1 (continued):
    - The Balancing Authority is experiencing conditions where all available generation resources are committed to meet firm Load, firm transactions, and reserve commitments, and is concerned about sustaining its required contingency reserves.
    - Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
- EEA 2: Load management procedures in effect:
    - The Balancing Authority is no longer able to provide its expected energy requirements and is an energy deficient Balancing Authority.
    - An energy deficient Balancing Authority has implemented its Operating Plan(s) to mitigate Emergencies.
    - An energy deficient Balancing Authority is still able to maintain minimum contingency reserve requirements.
- EEA 3: Firm Load interruption is imminent or in progress:
    - The energy deficient Balancing Authority is unable to meet minimum Contingency Reserve requirements.

Q. AWEC also provides that PGE's proposal regarding RCEs is one-sided because it does not account for hours when Mid-C market prices are negative. Do you agree?

A. No. Forward market price curves do account for the probability of low or negative prices in-so-far as the market expects that in the forward period, as do PGE's historical based Lydia market price shapes. This is why the MONET model includes hourly prices as low as $12/MWh. Consequently, MONET correctly reflects the expectation of low market prices. However, MONET does not capture the unique operating conditions associated with RCEs, which is why PGE included the RCE proposal in the 2024 NVPC forecast.

Q. What is OPUC Staff's recommendation regarding PGE's RCE proposal?

A. In summary, OPUC Staff recognizes that there is "ample reason to believe that capacity shortage events will be a continued threat to western grid reliability in the near future and that these costs are not easily modeled in MONET."[21] Consequently, Staff supports PGE's proposal to include an RCE-related cost forecast in the 2024 NVPC forecast, subject to certain adjustments.

Q. What issues does Staff raise regarding PGE's modeling of RCE expected costs?

A. Staff takes issue with the assumption that no wind is available in the day-ahead window to meet demand. Staff argues that this assumption is not reflective of actual available wind generation and that the day-ahead forecast of wind generation is a reliable predictor of actual wind generation. Therefore, Staff recommends removing the assumption of zero wind deliveries during RCEs. Staff's recommendation reduces the 2024 NVPC forecast by approximately $1.6 million.

Q. Do you agree with Staff's recommendation?

A. No. While PGE appreciates Staff's recognition of the threat posed by capacity shortage events, we disagree with Staff's proposed adjustment. PGE assumes zero wind availability for reliability purposes during super-peak hours in the RCE modeling, consistent with operational planning during RCEs. While Staff's analysis seems sound upon the limited time to review, Staff did not target their analysis to super-peak hours and instead analyzed the correlation between day-ahead wind forecasts versus actual generation.

Q. Why does PGE assume no wind availability for planning purposes during RCEs?

[21] Staff/300, Dlouhy/18 at 11-14

A. PGE declares RCEs for reliability purposes. Therefore, although one can make the argument that day-ahead forecasts can provide a good estimate of actual wind generation on a daily basis, for planning purposes PGE would not rely on that day-ahead forecast for super-peak hours when reliability is at risk. Assuming wind availability and not positioning the portfolio to ensure that PGE will meet its load serving obligation in the event that wind generation does not show up can result in increased reliability risk and exposure to exceptionally high market prices during the RCE. In the analysis workbook PGE provided in its supplemental response to OPUC Staff Data Request No. 180, Attachment 180-B, the day ahead wind forecast and hourly actual wind generation for prior RCE events was provided. In that historical data there are hourly day ahead wind forecasts as high as 627 MW for an hour where no actual wind generation occurred. This represents an unacceptably high reliability risk during times of market illiquidity. However, as previously described, the RCE true-up mechanism designed within the AUT and PCAM frameworks, ensures that any variance between the RCE forecast and actual costs incurred will be fully refunded/collected from customers.

Q. Does Staff make other recommendations in the section discussing RCEs?

A. Yes. Staff recommends that PGE integrate a forecast of benefits associated with WRAP participation in the 2025 NVPC forecast to account for the first possible binding season. Additionally, Staff recommends that PGE transition to a NVPC forecast model that allows for modeling of items that the current MONET model does not have capability to include.

Q. What is PGE's position regarding the two recommendations?

A. Regarding the WRAP, PGE will investigate and if there is an expectation that WRAP will provide benefits in 2025, PGE will model both the costs and benefits associated with participation in the WRAP. Regarding the use of a new forecasting model, PGE is currently exploring a variety of options and, should PGE identify an option more suitable for forecasting power costs than MONET, PGE will put forth a proposal in a subsequent AUT proceeding, should the Commission grant PGE the authority to include modeling changes in a non-GRC year, or GRC proceeding.

E. Physical Gas Call Option

Q. Did Parties provide recommendations regarding the 2024 winter physical gas call option proxy contract proposed by PGE?

A. Yes, both OPUC Staff and AWEC recommend that the physical gas call option proxy contract be removed from the 2024 NVPC forecast and oppose the inclusion of such a contract. While OPUC Staff recognizes the risk of gas price disruption and the prudence of this type of product, Staff argues that the MONET model is not designed to also account for the expected benefits associated with a physical gas call option. AWEC on the other hand, argues that option contracts are inherently imprudent and should not be included in customer prices.

Q. Please summarize Staff's recommendation.

A. OPUC Staff recommends removing the costs associated with the physical gas call option on the basis that PGE did not also model the potential benefits of having a call option. Staff argues that the "NVPC benefit of the physical gas call options should be at least as large as the cost of the call option on a risk-adjusted basis."[22]

Q. Please summarize AWEC's recommendation.

A. AWEC argues similarly that no associated benefits are accounted for in the NVPC forecast and therefore the cost of the physical gas call option should be removed. Additionally, AWEC

[22] Staff/300, Dlouhy/13, at 22-23

asserts that "option contracts, in general, are an uneconomic hedging method for ratepayers, and therefore, are not prudent."[23]

Q. Why does PGE include a physical gas call option in the 2024 NVPC forecast?

A. As previously described in PGE Exhibit 300, PGE included a proxy contract for a physical gas call option that will protect PGE and customers from gas price excursion risks during 2024 winter months.

Q. Why does PGE believe that such protection is necessary?

A. Operational experience from the last two years (i.e., 2021, 2022) indicates that the high natural gas market price and volatility will continue in future winter months and could result in significant power cost impacts. Therefore, to address the natural gas market price risk, we are planning to execute a physical natural gas call option to be effective in the months of January, February, and December 2024.

Q. Do parties agree that current gas market environment presents significant risks of price excursions and volatility?

A. Partially yes. Specifically, Staff states that they "take no issue with the Company's conclusion that the natural gas prices are expected to be higher and more volatile based on the experiences of the last two years."[24]

Q. Both Staff and AWEC argue that the physical gas call option should be removed because there is no associated benefit modeled in MONET. Is the physical gas call option expected to provide direct monetary benefits in MONET's modeling of the 2024 NVPC forecast?

---

[23] AWEC/100, Mullins/21 at 8-10
[24] Staff/300, Dlouhy/13 at 3-5

A. No. Physical gas call options can be viewed as a type of capacity contract that takes advantage of installed generating capacity as a low-cost method to acquire capacity during winter months, when gas markets are expected to be most volatile. However, although these types of capacity products do not provide a direct monetary benefit under the MONET deterministic, normalized environment, they benefit customers by protecting against large power cost variances.

Q. Did PGE or other utilities experience recently large power cost variances due to gas price excursions?

A. Yes, both PGE and PacifiCorp experienced significant power cost variances during December 2022 due to gas price excursions. While PGE experienced a $14.2 million power cost variance during December 2022, PacifiCorp incurred a power cost variance of approximately $35.7 million, according to PacifiCorp's 2022 PCAM filing in Docket No. UE 421. Therefore, utilities and customers face significant risks of increased power costs due to the gas market volatility. Physical gas call options reduce this exposure and risk through surety of fixed price delivered physical gas.

Q. Please elaborate on the mechanics of how a physical gas call option benefits customers.

A. The physical gas call option has two critically important attributes during extreme market volatility: 1) it is physical natural gas product, and 2) it is delivered to PGE firm transport on the KB Pipeline. A physically delivered natural gas call option allows PGE and customers a cost-effective way to obtain daily physical gas during the most volatile winter months. Additionally, the ability to daily call on delivered physical gas at a fixed price, provides PGE and customers the benefit of not being subject to extremely volatile daily prices.

Q. AWEC argues that a physical gas call option contract is "an inferior form of hedging relative to […] physical forward contracts and financial swaps" and, "because ratepayers can receive the same hedging benefit from a swap at lower cost, option contracts are inherently an imprudent form of hedging."[25] Do you agree?

A. PGE disagrees. As evidence, at the time when PGE quoted the physical gas call option, the price of the option for the January, February, and December 2024 was approximately 44% less than the price of the entire financial winter strip (i.e., equivalent of a financial swap). Additionally, the physical gas call option provides customers with a capacity benefit compared to a financial swap because PGE can call on physically delivered gas via the option during the highest winter load months.

Q. AWEC also supports its proposal to remove the physical gas call option by referring to a Commission decision in Docket No. UE 181 regarding certain capacity contracts included in PGE's 2007 NVPC forecast. What does AWEC argue?

A. AWEC argues that the Commission decision issued in UE 181 (Commission Order No. 07-015) provides a precedent that supports their recommendation to exclude the extrinsic value of any potential physical gas call option that might be executed over the course of this proceeding. Furthermore, AWEC quotes a paragraph that seems to support their proposal but conveniently leaves out other relevant parts of the Commission Order such that AWEC fails to provide the entire context of the decision in UE 181.

---

[25] AWEC/100, Mullins/21-22, at 16-17 and 1-2

Q. Please provide a brief summary of the issue AWEC is referring to and the Commission decision in UE 181.

A. In the 2007 NVPC forecast that was litigated in UE 181, PGE included two capacity agreements. Similar to the proxy physical gas call option included by PGE in the 2024 NVPC forecast, those contracts were not intended to dispatch in the MONET modeling but were necessary for extreme circumstances to maintain reliable delivery to customers. Also similar to this case, AWEC (then ICNU) recommended the Commission remove these contracts from the forecast or, as an alternative, include a calculated extrinsic value of these contracts in the NVPC forecast.

Q. Did the Commission adopt AWEC's recommendation to remove the contracts from the 2007 NVPC forecast in UE 181?

A. No. The Commission's resolution as provided in Order No. 07-015 stated that:

> "We agree that the costs of these contracts should be included in PGE's test year power costs. The contracts assure supply for peak loads and emergency events, and therefore provide service to customers."[26]

Q. Please summarize your position regarding AWEC's and Staff's recommendations?

A. PGE does not agree with Staff's and AWEC's recommendations. The proxy contract for a physical gas call option included by PGE in the 2024 NVPC forecast ensures low-cost capacity from installed generating capacity and protects PGE and customers against expected gas market price excursions and volatility. Additionally, to address AWEC's position that placeholder contracts are not appropriately included in the NVPC forecast, PGE clarifies that

---

[26] See Commission Order No. 07-015 at 13

the proxy contract for a physical gas call option that is currently included in the forecast will either be replaced by an actual contract should PGE execute it before the MONET updates deadline, or be removed, if PGE will not execute a physical gas call option.

F. Other Items

1. Schedule 125 Changes

Q. Which parties raise issues on PGE's proposal regarding changes to Schedule 125 guideline?

A. CUB raised issues in CUB Exhibit 100. Staff provided discussion regarding PGE's proposal in Staff Exhibit 700. Because Staff did not address this issue within the 2024 NVPC procedural schedule, PGE will respond to Staff's testimony in reply testimony to be submitted on July 21, 2023.

Q. What is CUB's recommendation?

A. CUB opposes PGE's proposal to be allowed to introduce modeling changes in non-GRC years and instead recommends that "PGE be allowed, for only the 2025 and 2026 Annual Update Tariffs (AUTs), to propose modeling changes relevant to PGE's participation in the Western Resource Adequacy Program (WRAP) and the implementation of the regional Extended Day-Ahead Market (EDAM)."[27]

Q. What are CUB's concerns?

A. CUB argues that they have limited ability to review complex modeling changes and states concerns that "a compressed schedule along with numerous modeling changes will make it hard for parties to understand complex new modeling enhancements." Additionally, CUB is

---

[27] CUB/100, Gehrke/11 at 12-15

concerned "about the volume of modeling adjustments that could be considered within the AUT's compressed timeline."[28]

Q. How do you respond to CUB's concerns?

A. In their reply testimony, CUB did not address any of the arguments put forth by PGE in opening testimony, including that recent history demonstrates that parties actually have ample time to review PGE's proposed modeling changes within the AUT procedural schedule. Supporting evidence is PGE's 2022 AUT, where PGE proposed extensive modeling changes and parties thoroughly reviewed PGE's filing, while also submitting and receiving responses for 189 data requests. CUB did not raise an issue regarding their inability to review PGE's proposed changes in the 2022 AUT.

Q. You describe in PGE Exhibit 300, PacifiCorp is allowed to propose NVPC forecast modeling changes in non-GRC years. Did CUB raise similar concerns in PacifiCorp's Transition Adjustment Mechanism filings?

A. No. PGE reviewed recent records and did not find an instance where CUB argued that PacifiCorp should not be allowed to propose modeling changes within the TAM proceeding. Additionally, it should be noted that PacifiCorp's TAM filings are on a similar procedural schedule to PGE's AUTs.

Q. CUB proposed that PGE be allowed to propose only modeling changes associated with WRAP and EDAM. Do you agree?

A. No. The WRAP and EDAM are just two items that PGE expects to require more complex modeling changes. However, other impactful items listed by PGE in opening testimony are the expected changes to the regional market supply and demand fundamentals in the short

[28] CUB/100, Gehrke/11 at 17-20

term and the decarbonization directives under HB 2021 in the mid-term, until 2030. CUB does not address the first item and completely dismisses the complexities regarding meeting HB 2021 decarbonization directives.

Q. CUB's assessment is that it is not appropriate to allow PGE to propose modeling changes due to HB 2021 in 2024 and 2025. Do you agree?

A. No. Firstly, CUB seems to have included year 2024 inadvertently in their discussion since we are processing the 2024 NVPC forecast in this current proceeding. The path to meet HB 2021 decarbonization directives by 2030 and beyond, will require that PGE makes annual progress toward achieving the emission reduction goal. Therefore, impacts of HB 2021 will likely be seen earlier than 2030, with the addition of battery storage and other renewable resources in the region. As evidence, PGE recently announced the acquisition of approximately 475 MW of battery storage.[29] Therefore, it is expected that the regional market supply and demand fundamentals will be impacted and potentially require modeling changes to reflect an NVPC forecast as accurate as possible.

Q. Please summarize your position on CUB's recommendation.

A. We do not agree with CUB's recommendation. Recent PGE AUT history and the fact that PacifiCorp's TAM allows modeling changes while operating under a schedule that is similar to PGE's AUT demonstrates that parties have the ability to review modeling changes within an AUT procedural schedule.

[29] See: https://investors.portlandgeneral.com/news-releases/news-release-details/pge-bolsters-reliability-clean-energy-transition-regions-largest
https://investors.portlandgeneral.com/static-files/97c77154-41db-408e-9e02-5c8e76fe920b

<u>2. Balancing Impacts</u>

Q. Please discuss the Balancing Impacts adjustment included in PGE's overall proposed reduction to PGE's 2024 NVPC forecast?

A. AWEC describes that each of their proposed adjustments was modeled as a one-off calculation. Consolidating all proposed adjustments in a final MONET run resulted in an additional reduction of $2.4 million, beyond AWEC's cost adjustments for each individual recommendation. Therefore, AWEC is including this amount in the totality of their $161.9 million recommended reduction to PGE's 2024 NVPC forecast.

Q. Do you agree with this adjustment?

A. No. As described in this testimony, we do not find that any of AWEC's adjustments are reasonable because they are opportunistic in seeking benefits, based on erroneous calculations, or simply unsupported by reasonable argumentation. Therefore, since the balancing adjustment is a by-product of consolidating all AWEC's recommended reductions in a final MONET run, we do not agree that this is a reasonable reduction to the 2024 NVPC forecast.

III. Conclusion

Q. In closing, please summarize your positions regarding the issues identified by parties.

A. We recommend the Commission reject Parties' positions regarding the issues identified. As discussed and demonstrated in our testimony, parties' proposed adjustments are largely based on inaccurate calculations and misguided assumptions, are unrealistic and opportunistic in seeking benefits without recognizing associated costs and risk. Parties' recommended reductions would unfairly introduce a significant and unreasonable downward bias on PGE's NVPC forecast and significantly increase the risk of generation reliability, making it unlikely that PGE would recover its prudently incurred NVPC for 2024.

Q. Does this conclude your testimony?

A. Yes.

IV. Qualifications

Q. Ms. Pedersen, please describe your qualifications.

A. I received a Bachelor of Science degree in Industrial Engineering from Northwestern University, Chicago, IL in 2010. I also hold a Master of Science in Applied Statistics from Pennsylvania State University in 2016. I have worked for five years at PGE mainly as the Portfolio Optimization modeler. Currently, I am the interim manager of the Power Cost Forecast department and will take over the principal analyst role on that team when my interim assignment ends. Prior to PGE, I worked at Intel as an industrial engineer supporting capacity and factory simulation models and later as a sales operations analyst.

List of Exhibits

PGE Exhibit	**Description**
1501C	Flexibility Reserves Modeling: Technical Description of PGE's Analysis