Portland General Electric Company
121 SW Salmon Street • 1WTC12 • Portland, OR 97204
portlandgeneral.com

October 1, 2024

Via Electronic Filing

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

RE: UE 435 – In the Matter of Portland General Electric Company, Request for a General Rate Revision

Dear Filing Center:

Enclosed for filing today in the above-reference docket is Portland General Electric Company's (PGE) Surrebuttal Testimony and Exhibits.

It has been served on all parties of record.

If you have any questions, please feel free to contact me at (503) 464-7488. Please direct all formal correspondence and requests to the following e-mail address: pge.opuc.filings@pgn.com.

Sincerely,

Jaki Ferchland

Jaki Ferchland
Senior Manager, Rates and Regulatory Affairs

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 435

Surrebuttal Overview

PORTLAND GENERAL ELECTRIC COMPANY

Surrebuttal Testimony of

Jaki Ferchland
Chris Liddle

October 1, 2024

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I. Introduction

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

A. My name is Jaki Ferchland. My position is Senior Manager of Revenue Requirement, Regulatory Affairs. My witness qualifications appear at the end of PGE Exhibit 200.

My name is Chris Liddle. I am Senior Director, Risk Management and Assistant Treasurer. My qualifications can be viewed at the end of PGE Exhibit 600.

We are adopting the testimony of Pope-Sims from PGE Exhibit 100.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to restate the most relevant and key positions of PGE's filing for a 2025 rate review. We emphasize the critical investments we have undertaken on behalf of our customers, while simultaneously reiterating the importance of addressing affordability concerns. Furthermore, we address a few key issues raised by parties in rebuttal testimony, and we continue to discuss overarching themes we have identified by parties throughout this rate review. We believe these warrant the Commission's careful consideration as they evaluate the evidence and facts presented by PGE and other parties involved in this case.

Q. What is PGE's total anticipated price change for 2025?

A. Table 1 presents the anticipated total rate change for January 1, 2025, which notably reflects the recent changes due to Commission-ordered delays in the procedural schedule for Docket UE 427 resulting in a March 1, 2025 effective date for the Clearwater Wind facility renewable automatic adjustment clause (RAAC).[1] It also reflects updates to PGE's known supplemental schedules.

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[1] The tariff will be suspended until March 1, 2025, *See In the Matter of Portland General Electric Company, Renewable Resource Automatic Adjustment Clause* (Schedule 122) (Clearwater Wind Project), Docket UE 427, Order No. 24-308 (Sep 13, 2024).

Table 1[2]
Comparison of average price change for January 1, 2025 reflecting Commission-ordered delay on Clearwater Wind facility

	At Reply Testimony	Current	Current - Residential Only
Base Rates in this proceeding	6.3%	8.6%	7.9%
Power Costs in Docket UE 436	3.1%	0.3%	0.4%
Supplemental schedules	-0.7%	-0.3%	0.1%
Total	8.7%	8.6%	8.4%

After January 1, 2025, we anticipate a rate decrease of approximately 1% on March 1, 2025 for the 2024 Clearwater Wind facility which will remain in customer prices for a year, and a rate increase of 1.3% for the Seaside battery energy storage system (BESS) in mid-year 2025.

Q. What is PGE's request in this rate review filing?

A. As illustrated above, PGE's base rate revenue request has changed due to Commission-ordered delays in the procedural schedule for UE 427 for the Clearwater Wind facility. As a result, Clearwater Wind facility price impacts will not be included in customer prices prior to the January 1, 2025 price change, which had previously been assumed in PGE's opening and reply testimony of this case. While this rate review focuses solely on base business prices, not power costs, PGE's January 1, 2025, price change must now reflect an additional $68 million for Clearwater Wind base rate amounts in 2025 relative to 2024. However, this increase is more than offset by approximately $96 million of Clearwater Wind power cost benefit, reflected in PGE's power cost update in Docket UE 436 (UE 436), also effective January 1, 2025. In addition to this change, PGE made minor updates to reflect its September load update and the removal of a supplemental schedule[3] from current revenues. Table 2 below steps through these changes.

[2] Total may not foot due to rounding.
[3] Schedule 131 was previously included and should be removed as it is not a base rate.

Table 2
Change from PGE reply testimony January 1, 2025 base rate amounts to surrebuttal testimony base rate amounts

Steps	$ in millions	Percent
Reply testimony base rate change	$ 190.5	6.3%
Commission delay of Clearwater Wind facility	68.0	2.3%
September load update and Sch 131 changes	2.3	0.1%
Surrebuttal decreases	(3.0)	-0.1%
Total base rate change	$ 257.8	8.6%

For clarity, the Clearwater Wind facility in aggregate serves as a 1% price reduction to PGE's total January 1, 2025 proposed price change. This was not previously identified in this docket as it was meant to reduce customers prices during 2024 through the UE 427 proceeding.

Q. How will the price change in UE 436 change as a result of this update?

A. Without the change for Clearwater Wind, the October 1, 2024, power cost update in UE 436 would have been approximately 3.5%. With the change due to Clearwater Wind, the power cost update results in a minimal 0.3% price change January 1, 2024.

Q. Does this change materially alter PGE's request in this case or in the power cost update proceeding?

A. No. The change for Clearwater Wind is an issue of timing impacting the starting value, not the ending value. PGE's revenue requirement inclusive of both base rates and powers costs has remained consistent and only reflects expected changes for the September load forecast, the October 1 MONET update, and a $3 million reduction offered by PGE in this surrebuttal testimony for base rates.

Q. What else has changed during this proceeding?

A. Within this proceeding, PGE is requesting that the 200 MW Seaside battery energy storage system be included in prices mid-year when the facility begins serving customers. In our initial request, PGE proposed to fully offset this cost for the first full year with investment tax credits

(ITCs) to be returned to customers over an accelerated five-year front-end declining basis. However, in their opening testimony, parties to this case requested the Commission reject this approach, and instead use the credits to offset rate base over the life of the project through the revenue requirement. Given PGE's desire to return these credits in the most beneficial manner possible and parties' preference for this method, PGE altered its treatment of the credits in its reply testimony to match Staff's and, now, CUB's proposals. As a result, instead of a 0.1% rate decrease mid-year in 2025, the inclusion of Seaside mid-year now represents a 1.3% rate increase.

Q. Please restate the key elements of your filing driving the described price changes.

A. From late 2023 through 2024, PGE has made significant and necessary investments, primarily in our transmission and distribution system and in clean capacity for power generation. Our investments address regulatory compliance, replacement of aging assets, and evolving customer needs. They also include two utility-scale battery energy storage systems set to serve customers by end-2024 and mid-2025. Approximately 75% of our rate review request relates to new capital investments. In addition, limited operating and maintenance expense increases are due to inflation, insurance premiums, vegetation management, and a virtual power plant implementation. These investments, which benefit the operation of the system and serve our customers, were not accounted for in our previous rate review. While we have managed our costs well, load growth on the system, inflation, and the cost of needed capital investments have outpaced our cost-control efforts. This drove the need for this new filing to accurately reflect our cost of service. Each element is crucial to maintaining safe and reliable power delivery for our customers.

Q. Has any organization outside of PGE offered a voice in support of the ongoing work PGE is performing and associated price changes?

A. Yes. The International Brotherhood of Electrical Workers (IBEW) Local 125 urges the Commission not to delay vital work crucial for Oregon's growing economy. As both workers and customers, they advocate for a more resilient and reliable electrical system, viewing it as essential for addressing community threats and ensuring continued economic growth opportunities for the state. IBEW's full letter is included as PGE Exhibit 2101.

Q. Are there any proposals made by parties to this case that PGE would like to highlight?

A. PGE requests that the Commission reject the following proposals:

- AWEC's request to fully reject PGE's filing because PGE used its 2024 budget based on its recently completed rate review as the basis for comparison in this filing. This is discussed below in Section IV-A.
- CUB's proposal to alter the price effective date, as discussed in PGE Exhibit 2200.
- Staff and AWEC's proposals to fundamentally alter how rate base is calculated by either mismatching year-end and average values or by using a historic average test year in a future test year state. This issue is further reviewed in PGE Exhibit 2400.
- CUB's proposal for a rate shock mechanism, as discussed in PGE Exhibit 2200.

Q. Have any settlements been achieved in this case to date?

A. No. While remaining time may be limited for achieving settlement, we remain committed to collaborating constructively with all stakeholders involved in this case. PGE is open to achieving a fair and reasonable settlement that appropriately balances the interests of all parties through continued good-faith negotiations.

II. Contextual Basis of the Current Regulatory Review

Q. Can you explain the rationale behind PGE's current rate request, particularly in the context of Oregon's energy future?

A. PGE's request is about laying the foundation for the future of the energy transformation in Oregon. We are acutely aware of the financial challenges our customers are experiencing, coinciding with a period when the utility industry is undergoing a fundamental transformation in energy sourcing and delivery methods. We recognize that neither halting the energy transition nor disregarding the imperative to maintain affordability within the cost-of-service model are viable options. We are focused on striking the balance between necessary system upgrades to enhance reliability and continue the energy transition, while also mitigating price impact on customers.

This pivotal moment requires innovative approaches and open dialogue among all stakeholders to ensure we can continue to provide reliable, sustainable energy services while remaining responsive to our customers' economic concerns. We are committed to exploring all avenues to navigate this complex landscape effectively, balancing the imperatives of the clean energy transition, grid modernization, regulatory compliance, and customer affordability.

As we discussed in PGE Exhibit 1000, since its last rate case, PGE has made substantial thoughtful investments in its transmission and distribution infrastructure. These investments are designed to reinforce and enhance the core components of PGE's energy delivery system, positioning it to effectively manage the anticipated significant transformations in power generation, storage, and energy delivery expected over the next five to fifteen years.

This proactive approach aims to ensure the robustness and adaptability of our grid in the face of evolving energy landscapes and technological advancements.

PGE must be reliable, safe and affordable as we become cleaner.

Q. What specifically is PGE doing to maintain the safety and reliability of the system for customers that necessitates this rate review?

A. In addition to the two utility-scale battery storage projects, PGE is making strategic investments to enhance both safety and reliability across our infrastructure. We are focused on investments through our FITNES[4] program for our distribution grid, which concentrates on the design and replacement of distribution poles to enhance their structural integrity and resilience against severe weather events. We are also modernizing our substation communications systems, replacing outdated equipment with new technology to ensure long-term reliability and improved performance. Additionally, we are undertaking substation upgrades and rebuilds to accommodate customer growth, implementing plant upgrades to meet environmental mandates, and widening access roads to critical grid locations to facilitate maintenance and emergency response. Furthermore, PGE is investing in advanced grid technologies, including the installation of communicating, switching, and reclosing devices, along with associated substation upgrades. These enhancements will enable the implementation of fault location, isolation, and service restoration (FLISR) capabilities, significantly reducing outage durations for our customers in the future.

Q. Has PGE made any changes to this rate review filing since first filing in February?

A. Yes. In reply testimony, PGE reduced its request in this case by $18 million, this reflected multiple reductions including a decrease of PGE's ROE from 9.75% to 9.65%. PGE is

[4] Facilities Inspection and Treatment to the National Electric Safety Code (FITNES).

reducing its request by another $3 million for certain insurance and other expenses shown in PGE Exhibit 2400. This results in a total reduction to PGE's initial request of $21 million.

Additionally, in reply testimony PGE withdrew its requests for the investment recovery mechanism and associated storage to acknowledge the comments received by stakeholders. However, parties have requested that the associated storage issue continue to be litigated and ruled upon by the Commission. As such, PGE has provided prior responsive testimony on this topic as PGE Exhibit 2805.

Q. In this surrebuttal, is PGE recommending altering its rate effective date?

A. No, PGE maintains it request for a January 1, 2025 rate effective date as discussed in PGE Exhibit 2200. PGE filed this rate case with the same timing that we have filed nearly every case in the past 30 years. We have performed our financial planning around this timing, and while we will explore alternative timing in the future, we cannot alter the planning and the timing mid-stream without major financial challenges. Further, PGE recognizes that customer bills can ebb and flow depending on the time of year, regardless of rate changes and, therefore, we offer an equal pay option that works to flatten customers' bill throughout the year that has over 51,000 enrollees. We urge customers who experience more significant usage in the winter months to sign up for PGE's equal pay option to help level the cost of utility bills throughout the year.[5]

Although we are not altering our primary request for a January 1, 2025 price effective date, PGE is alternatively proposing a price effective date of either April 1, 2025 but with the ability to collect the full 2025 revenue requirement. This would result in a higher price change on the effective date, which would be reduced to the annualized value at the end of 2025.

[5] https://portlandgeneral.com/equal-pay

This proposal is discussed in further detail in PGE Exhibit 2200. For both the January 1 and April 1 proposals, customers would provide the same amount of revenue in 2025.

Q. Is it important for PGE's prices to be based on its cost to serve customers?

A. PGE maintains its position that, as a fully integrated electric utility focused primarily on regulated operations serving electricity customers, it is crucial that our pricing structure accurately reflects the costs associated with providing reliable and efficient service. We firmly believe in the principle of cost-based pricing to ensure transparency and fairness in our operations.

Furthermore, we respectfully challenge any notion that the cost of service can be set without a complete and objective review and full accounting of the costs a utility expects to incur to serve customers. If a utility's revenue requirement is mandated to be below the actual cost of serving customers, it becomes unrealistic for the utility to be able to meet all of the requests and obligations set forth by customers, regulators and other stakeholders.

Q. Parties are saying you are not going far enough on affordability, how do you respond?

A. PGE acknowledges parties' calls for accelerated progress in addressing affordability. Given the importance of this topic, PGE is committed to implementing evidence-based solutions supported by data and research. It is important that our initiatives are effective and sustainable.

PGE pioneered the region's first income-qualified bill discount program, which has grown significantly in size and scope since being launched. Available discounts have expanded from an initial maximum 25% to a current maximum 60% discount. Recently, we completed a comprehensive energy burden assessment designed to better identify and help support those most in need.

In our ongoing efforts to enhance affordability, PGE is partnering with the Energy Trust of Oregon to improve energy efficiency and reduce energy consumption in households, thereby reducing the energy burden on customers who need it most.

PGE also offers a range of flexible bill payment options designed to help customers control their energy costs. We are committed to developing and implementing innovative solutions to address affordability concerns while ensuring the reliability and sustainability of our services. We disagree that the only method for addressing affordability concerns is aggressive reductions to the prudent cost of service.

Affordability is critical, and so too is safe, reliable power as society and our industry transform. As an electric utility providing a necessary service, PGE must view service to customers from the perspective of "and" not "or". That is -- our service must be affordable *and* reliable *and* safe. PGE is doing its utmost to deliver these critical elements of being a provider of last resort for a vital service our customers depend upon.

Q. How does PGE respond to Staff's statement that "disconnections for nonpayment and arrears remain higher than pre-pandemic levels[?]"[6]

A. We understand Staff's concern, however, disconnections and arrears are consistent with historical trends prior to the COVID-19 pandemic. For additional information and details on this topic please see PGE Exhibit 2300.

Q. What is PGE's approach to aligning cost-of-service pricing with customer affordability concerns?

A. To advance Oregon's clean energy transition while maintaining safety, reliability, and affordability, PGE must take a balanced and comprehensive approach. It is crucial that our

[6] Staff/2300, Dlouhy-Scala/4 at 17-18.

problem-solving strategies address all aspects of these challenges, rather than focusing on any single dimension over the others. We continue to support a multi-faceted strategy to maintaining balance between the cost to serve safely, reliably and affordability.

In our reply testimony, we highlighted four critical areas of need. First, we must maintain operational efficiency by continuously seeking to optimize operations and reduce costs without compromising service quality or essential investments. Second, we must offer and enhance targeted customer assistance programs, such as low-income energy assistance, flexible payment plans, and energy efficiency initiatives to help customers. Third, regulatory tools need to be available to the utility during a time of significant change and growth to allow for timely alignment of our revenue with actual costs, which promotes more stable and predictable pricing. Finally, we addressed the need for constructive stakeholder collaboration with consumer advocates, policymakers, and other stakeholders to develop effective solutions.

In addition to these four areas of need, we propose two more. A need for innovative rate design that explores rate structures that reflect true costs while considering affordability impacts and make sure that the right customer classes are contributing to the appropriate portion of the utility's revenue need. Work in this area is already underway and should continue. Second, long-term planning that focuses on sustainable infrastructure investments to manage long-term costs effectively.

By addressing these six key areas – operational efficiency, targeted assistance, regulatory tools, stakeholder collaboration, innovative rate design, and long-term planning – PGE aims to strike a balance between meeting clean energy goals and maintaining affordable, reliable service for all customers. This comprehensive approach will be crucial in successfully navigating the challenges and opportunities of Oregon's energy transition and in the face of increasing extreme weather and climate driven events.

III. Transparency Regarding Rate Increases

Q. How does PGE plan to address the various claims of a lack of transparency made by some parties to this proceeding?

A. In the next two sections, PGE will address and clarify certain statements made in testimony and media reports regarding this case. These statements, in our view, have at times been one-sided, inaccurate, or based on misconceptions. Given the critical nature of these proceedings and the importance of maintaining the integrity of the process, we believe it is necessary to provide balance and correct any inaccuracy. Our goal is to ensure that all parties have access to accurate and comprehensive information to inform their decisions.

Q. CUB claims that PGE is not being transparent on its price change by stating that our "case summary does not reflect the actual rate increase that PGE is proposing."[7] Does PGE agree?

A. No. Nor have we "changed what costs are included in [our] case summary."[8] Even with the Commission-ordered change for Clearwater, PGE's costs in this case remain the same. PGE's opening testimony and reply testimony both spoke to the dollars that are being requested within this proceeding and they do not include costs from other proceedings. CUB, however, focused on percentages and not the dollars. In doing so, CUB uses *other* proceedings as reason to imply that PGE's request in *this* proceeding is unnecessary. While PGE shared an anticipated all-in estimated value for price changes in 2025 in its opening testimony, once it became clear that outcomes in other dockets were being used to attack the prudence of items in this one, PGE wanted to make clear what we are requesting within this docket.

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[7] CUB/400, Jenks/5 at 12-13.
[8] CUB/400, Jenks/8 at 4-5.

Since PGE submitted its initial testimony in this proceeding, CUB has vigorously challenged PGE's financial management practices, questioning PGE’s cost control measures and expenditure decisions both in their testimony of this case and in the media and blog posts. The selection of words often suggests that PGE is requesting amounts *within this proceeding* that push well past a 10% increase, which is not accurate. Even with the change for Clearwater Wind, PGE’s request in this case has never even exceeded 10%. Nor has the totality of known changes in 2025, when considering estimated impacts in other proceedings, exceeded 10%. In light of CUB’s approach to include costs that are subject to separate proceedings and not under review in this case, PGE found it necessary to make clear when identifying the percentage in its reply testimony that this proceeding was solely addressing a proposed rate increase of 6.3%, which is now 8.6% as a result of the Clearwater Wind removal from anticipated current prices, which is outside of PGE’s control and purely a timing decision resulting from a delay in the UE 427 procedural schedule and tariff-effective date. This factual distinction is important to ensure accurate representation of the request under consideration.

Further, the discussion around price changes presented as percentages is particularly complex, as evidenced by the changes PGE needed to make in this final round of testimony. Again, PGE has not changed our request in terms of additions for capital, operating and maintenance expense, or a cost of capital, but because the starting value for calculating the difference between 2024 and 2025 for the Clearwater Wind facility has changed, there is a perceived $68 million additional increase relative to PGE’s prior testimony.

Q. Is it possible for PGE's total rate increase, inclusive of values from other dockets, to move above 10% in 2025?

A. It is possible that other schedules, when updated with the latest information, particularly when power costs are updated in November as a result of changes in market power and fuel prices, that costs could move higher; it is also possible that they could move lower if market power or fuel prices go down. These costs, whether for bulk electricity purchased to serve our customers, or fuel for the generation of electricity, naturally vary due to market conditions and agreements with third parties.

Q. At any point has CUB provided an incomplete picture of PGE's price increase?

A. Yes. In rebuttal testimony, CUB showed an 11.0% figure. PGE sent a data request to CUB to understand why they had not included their own proposal on ITC treatment, which affords customers a 0.3% decrease during 2025.[9] CUB subsequently filed an *errata* to their testimony to adjust their value downward. They have yet to make any adjustments to recognize other schedule changes as provided by PGE in discovery.

Q. Has CUB made any other statements regarding PGE's price changes that could be seen as misleading?

A. Yes. CUB's reference to an "18% increase"[10] is stated more than once, and it is stated in the same manner by Staff.[11] Both parties' statements appear to suggest that 18% was the price increase PGE received for 2024. However, PGE did not receive an 18% increase, we received a 16.5% increase. While we agree that residential customers in isolation received an 18% increase, the topic at hand is transparency, and we find it misleading that in every space

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[9] Note that CUB's own proposal on this matter results in a 0.3% decrease, whereas PGE's initial proposal resulted in a 1.7% decrease.
[10] CUB/400, Jenks/3 at 8; CUB/400, Jenks/8 at 18; and CUB/400, Jenks/10 at 17.
[11] Staff/230, Dlouhy-Scala/3 at 21.

possible, PGE's actual requests and outcomes are being inflated. To be clear, there is no reference to residential customers by either CUB or Staff in most of their references to the 18% value and nowhere do they mention the 16.5% overall price change for PGE. A true 18% increase for PGE would have resulted in approximately *$45 million* of additional revenue; our increase in 2024 does not reflect that.

Q. Setting aside the inaccurate articulation of PGE's total price change, is PGE's focus on the current proceeding's rate request, rather than on price changes from other proceedings, indicative of a lack of transparency?

A. No. The assertion that PGE lacks transparency because we are focused on this proceeding's request is unfounded. This proceeding on its own requires significant detail, support, and review. We find it illogical to argue that the outcomes or changes occurring in other dockets -- particularly those where costs are largely outside PGE's control -- are appropriate to use as support for a downward bias on the prudent costs PGE is seeking to recover in this docket.

Furthermore, PGE is proposing changes within this proceeding to increase transparency in future rate reviews. This is reflected in our efforts to work with stakeholders to improve bill design and our proposal to move power costs into a separate schedule for future clarity on the line between power costs and base rates.

Q. What other aspects of PGE's rate changes have parties discussed without providing full context?

A. Parties have attempted to depict PGE as unreasonably requesting an unnecessary price change and one that was not critical at this time.[12] Staff and CUB have highlighted bill increases in recent years totaling up to 40% to support this perception.[13] They aim to convince the

[12] Staff/100, Beitzel/3 and Staff/2300, Dlouhy-Scala/7.
[13] Staff/200, Scala/20 at 1-2.

Commission that our request is excessive and unjustified, especially considering recent price changes. However, the parties have not effectively refuted the substantive evidence provided by PGE depicting the underlying factors contributing to the need for cost recovery through this case.

Q. Can PGE provide any insight into what has driven up prices in recent years?

A. Yes. For example, nearly 10% of PGE's 2024 total price change of 16.5% were attributed solely to power cost increases, which would have occurred with or without a general rate review filing. Power costs are driven by the prices the utility must pay for fuel and power purchased on the open market and the utility's energy and capacity needs, both of which are largely outside of PGE's control. When examining what costs have been the real drivers of change over the past five years, power costs stand out.

PGE's 2019 prices included power costs of $361.5 million, this value grew to $959.0 million as of 2024, and it has grown further to $982.5 million as of today's October 1 update filing.

Power costs, meaning the prices PGE has had to pay for fuel and electricity purchase on the market, have nearly tripled in five years.[14] PGE makes every effort to mitigate the effect of these market dynamics on power cost prices. This is not a reflection on PGE's management of power costs. This is an effect of volatile and increased power costs in the region to which PGE is not insulated. PGE does not have a spending problem. The region has a power cost problem.

The expectation that we must simply absorb our remaining costs to do business because of other external costs largely outside our control, and for which we do not earn any return, is

[14] Electric load grew by approximately 15% over the same period.

unreasonable and unrealistic. This approach represents a flawed business model that does not account for the realities of utility operations and could ultimately compromise our ability to provide reliable service to our customers.

Q. What operating and maintenance expenses have been reflected in customer prices over the same period?

A. PGE's 2019 prices included base operating and maintenance expenses of $562.0 and this value increased to $645.0 million in 2024. This is growth of 14.8% over the last five years. Over this same period, all urban CPI was 21.8%.[15] PGE's request in this proceeding would only adjust our expenses to inflation that occurred from 2019 to 2025.

Q. Is there any other information PGE would like to offer regarding its price proposal in this proceeding?

A. There are no prescribed regulatory guidelines that identify if or how content from other dockets should be included in a rate review filing. Prior to 2022, PGE's standard practice was to solely identify the rate increase being sought within the filing itself. In an effort to enhance transparency and provide a more comprehensive overview for our customers, we began discussing total rate changes in the 2022 rate review. However, this proactive approach to disclosure is now being used to challenge our position in the current proceeding.

PGE is open to sharing within a rate review the costs occurring in other proceedings, but we become reluctant to focus on these values when they are used as a reason to argue for significant decreases in the current setting. Costs in other proceedings should not determine the prudence of proposals in this one.

[15] PGE Exhibit 2102.

IV. Transparency and Objectivity of the Rate Review Process

Q. Please describe the support that PGE has provided to support this rate review.

A. PGE has now provided nearly 2,000 pages of written testimony detailing the need for each increase and how our invested dollars serve customers. We have responded to approximately 1,120 data requests with thousands of pages totaling 17 GB of responsive materials. These materials have included financial information, details about specific accounts, descriptions of work, materials presented to our board of directors on our activities, detailed project documentation for over 90% of the capital investments made in this case, and much more.

Q. Staff states that "PGE's focus on dollar-for-dollar, immediate recovery rather than transparency into spending discipline or the value that customers are receiving for these increased costs."[16] How do you respond?

A. Not only does Staff's statement contradict the materials identified above, but Staff has not provided substantiated evidence or specific details to support their assertion that PGE has lacked transparency regarding spending discipline in this case. It is worth noting that all testimonies provided in this case, including both opening and reply statements, have extensively addressed the critical nature of PGE's ongoing work and the tangible benefits customers are receiving as a result of the expenditures in question. For example, this is a quote from PGE's reply testimony regarding PGE's capital spending:

> Over the past year, PGE has been actively investing in the modernization and fortification of its transmission, distribution and generation infrastructure. This initiative involves the critical maintenance and enhancements of our wind and thermal plants, systematic replacement of aging power lines and poles with more advanced and resilient infrastructure, as well as the upgrade of substations and transformers to enhance their durability and performance. PGE has also been implementing new grid automation and monitoring technologies to bolster the reliability and efficiency of its operations.
>
> Currently, PGE is in the process of completing the installation of two utility-scale

[16] Staff/2300, Dlouhy-Scala/3 at 15-17.

> battery energy storage systems, the Constable and Seaside projects. These systems will play a crucial role in supporting the integration of renewable energy sources into the grid, while also providing vital backup capacity to ensure a consistent and reliable power supply. Through its transportation electrification program, PGE has been proactively building out electric vehicle charging infrastructure to accommodate the growing demand for electric vehicles. Furthermore, the company has been deploying smart grid technologies and advanced metering infrastructure to enable more effective demand management and optimize energy usage across its service territory.
>
> Recognizing the critical importance of cybersecurity in today's digital landscape, PGE has been making strategic investments in state-of-the-art technologies to safeguard its systems and infrastructure against potential cyber threats and attacks.
>
> These initiatives are essential for maintaining the safety, reliability, and resilience of PGE's electric grid, thereby ensuring the consistent delivery of high-quality services to its customers. The company firmly believes that delaying or postponing these critical projects would be detrimental to the long-term sustainability and performance of its infrastructure and operations.[17]

Staff's assertion that PGE has not provided transparent explanations of its ongoing work or the value delivered to customers disregards the comprehensive information PGE has provided, including detailed testimony, data responses, and supplementary documentation, all of which substantiate our case. A thorough examination of the materials we have presented confirms the extent of our transparency and the clear articulation of customer benefits resulting from our initiatives.

Furthermore, PGE provided detailed support for over 60 capital projects of $3 million or more of investment in this case as a part of PGE's opening testimony and again during discovery. When PGE highlighted that no party has identified imprudent or unnecessary spending within the capital investments PGE has included in this proceeding, CUB's response was that they were too overwhelmed[18] to review all of PGE's project data. It is contradictory for two parties to simultaneously assert insufficient evidence and being too overwhelmed with information to review the evidence provided.

[17] PGE Exhibit 1100 at 21-22.
[18] CUB/400, Jenks/39.

Q. How does PGE respond to Staff's call for more information, data, and reporting to increase transparency?

A. PGE has been providing the PUC with increasing amounts of data through data requests, information requests, reports, and plans over the past five years. To illustrate this, PGE's six filed rate cases inclusive of a review of power costs from 2011 through 2019 required PGE to respond to approximately 600 data requests on average during the discovery period excluding the OPUC standard data requests. Since 2022, PGE is responding to more than double that amount. In addition to the integrated resource plan, we now have filed plans including a clean energy plan, a distribution system plan, a multi-year plan for demand response, a transportation electrification plan, a wildfire mitigation plan, and more. We recognize the importance of transparency and regulatory compliance, and we must also acknowledge that the compilation and submission of this growing volume of information requires substantial time and resources from PGE employees and others to review, making this a growing expense.

In light of this, we would request that PGE and the PUC work toward an approach that carefully evaluates the necessity of all the current reports, plans, compliance filings and data requests currently required. Our aim is to strike a balance between providing comprehensive data for effective regulatory oversight and maintaining operational efficiency. We believe that by collaboratively identifying the most pertinent and impactful information, we can enhance the efficiency of the regulatory process while ensuring that the PUC has access to all critical data required for thorough and effective oversight.

Q. How does PGE view the rate review process given calls for increased transparency?

A. PGE encourages increased stakeholder participation in our open, public regulatory process. We believe that the voices of our customers are welcomed, heard, and considered in the process. We recognize the importance of comprehensive and object communication regarding rate reviews, however, we are concerned that coverage of this rate review has primarily focused on percentages, without offering context and accurate explanation as to the underlying factors driving these adjustments, as provided by PGE.

For this reason, the regulatory process involves extensive documentation and analysis, which requires careful review by stakeholders who are engaged throughout the entire process. This in-depth examination is essential for a thorough review of the cost of service, an assessment of prudent utility management, and ultimately drives the determination of fair, just and reasonable rates.

We maintain that a simple focus on percentage changes, without considering the underlying data and rationale, does not provide a complete picture of the rate review process. We are committed to fostering a regulatory environment that encourages informed participation from all stakeholders. This approach helps ensure that rate decisions are based on a comprehensive evaluation of all relevant factors, ultimately serving the best interests of our customers and the community at large.

Q. Why is it important to engage in these proceedings like this?

A. Regulatory proceedings are structured to allow all parties to present their positions based on empirical data, evidence, and factual information. This framework enables other participants to either concur with or contest these positions, also using substantiated data and evidence. Throughout this rate review, various media outlets have commented on PGE's proposal, often repeating inaccurate information sourced from case participants. For instance, numerous media outlets and public communications have expressed concern over a purported "10.9%"

rate increase, which was never an accurate representation of the request in this case and was not a complete picture of PGE's total price change.

Within the formal regulatory process, PGE has the opportunity to address and rectify these inaccuracies. Which is why it became necessary for CUB to file an *errata* within this docket to reflect that the 11% price change they cited is actually lower as a result of their own ITC proposal. However, when erroneous statements or figures are circulated through media channels, correcting inaccuracies becomes significantly more challenging. This situation underscores the importance of upholding the integrity of the regulatory process.

V. Other Topics of Key Importance

A. Base Year Comparison

Q. What is AWEC's recommendation regarding PGE's proposed revenue requirement in this case?

A. AWEC is recommending that the Commission "reject this rate filing"[19] because PGE compares its 2025 future test year spending to its 2024 budget and not a base of 2023 actuals. AWEC states that the revenue requirement outcome of the 2024 GRC[20] was a stipulation and that the Commission does not approve budgets, and that PGE has not provided known and measurable evidence to support its case.

Q. How does PGE respond to AWEC's assertion that the "Commission does not approve budgets" and that the UE 416 outcome was "resolved through a settlement stipulation?"[21]

A. PGE has not asserted that the Commission approved its budget. Rather, we have stated that the revenue requirement approved by the Commission in Order 23-386 forms the basis and is relatively consistent with PGE's 2024 budget. We believe this is a more reasonable starting point for the current case.

AWEC's suggestion that the Commission did not approve of the revenue requirement proposed in the UE 416 simply because it was resolved through stipulations is unfounded. The Commission has the authority to reject stipulations if they disagree with the evidence provided, which did not occur in UE 416, where the Commission specifically found the

[19] AWEC/300, Mullins/1 at 17.

[20] PGE notes that throughout their testimony AWEC references PGE's "2023 GRC" which was actually PGE's 2024 GRC. We see this as further support that AWEC's sees general rate case proposals as historic and not future test years.

[21] AWEC/300, Mullins/2 at 2-4.

stipulation "results in fair, reasonable, and just rates."[22] As such, the fact that the revenue requirement was the result of a stipulation should not render its value useless as suggested by AWEC.

Q. Does PGE agree that a budget built from a revenue requirement approved less than a year prior is a poor foundation for establishing a future test year?

A. No. To our knowledge, there is no regulatory mandate requiring the exclusive use of historical actuals as a base year to serve as the foundation of a pro forma. When more pertinent information is available, it should be utilized for forecasting purposes. We disagree with the assertion that a budget, which establishes the financial framework for a multi-billion enterprise is an inadequate or unreliable basis for cost comparison to a future test year. Moreover, we take issue with the suggestion that our budget as unknown, immeasurable, or unquantifiable. This budget delineates specific expenditure values that align with the cost categories outlined in PGE's final UE 416 revenue requirement, providing a clear and quantifiable financial roadmap.

Q. How does PGE respond to AWEC's assertion that 2023 actual expenses were not provided for reconciliation?

A. As previously stated, PGE provided this information from the onset of this rate review filing.[23]

Q. How does AWEC address PGE's proposed future test year expense in their testimony?

A. Throughout AWEC's testimony, they propose reductions to each category of PGE's future test year O&M expenses by taking 2023 actuals, increasing it only by an all-urban CPI and comparing that value to PGE's 2025 test year value. This is no different than applying a

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[22] *In the Matter of Portland General Electric Company Request for a General Rate Revision; and 2024 Annual Power Cost Update*, Docket UE 416, Order No. 23-386 at 13, (Oct. 30, 2023).

[23] PGE/300, Trpik–Mersereau–Batzler/5 at Table 1, 7 at Table 2; PGE/400, Bekkedahl-Felton/7 at Table 2; PGE/500, Felton/7 at Table 1, 8 at Table 2, and 10 at Table 3.

historic test year. AWEC asserts that they are not applying a historic test year by simply renaming the exact work that represents a historic test year a "pro forma" study. To say that they have not confused the use of a future test year, and a historic test year based on this approach does not match the facts presented.

Staff takes a similar approach regarding many of their proposed reductions to PGE's 2025 test year O&M, however they do not propose to throw out PGE's case simply on the misguided assertion that PGE has used a 2024 budget as the basis of comparison.

Q. How did AWEC respond to PGE's assertion in reply testimony that AWEC's proposed reductions based on 2023 actuals fail to consider PGE's actual regulated ROE of only 7.18% in 2023?

A. AWEC did not provide any response to this point.

Q. Did AWEC make any attempt to examine PGE's current year 2024 actuals to see if they are indeed consistent with PGE's 2024 budget?

A. No. AWEC maintains that actual spending data is the sole reliable method for validating projected future spending and they contend that they have no means to verify the accuracy of PGE's 2024 budget. However, it is now September, and it is noteworthy that AWEC did not submit any data requests to compare PGE's 2024 actual expenditures to-date against the 2024 budget projections, which could have provided valuable insight into the budget's accuracy and reliability.

Q. How is actual spending in 2024 tracking to PGE's 2024 budget provided in this case?

A. PGE has eight full months of actuals to compare to its 2024 budget, which shows that PGE is spending nearly in line to what was budgeted by category.[24] Essentially, actual spending in

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[24] PGE Exhibit 2405.

2024, is far more reflective of PGE's 2024 budget, which was premised on the outcome of UE 416, than it is of 2023 actuals. As such, if AWEC's proposals for O&M were adopted in this case, it would likely require PGE to implement drastic measures to decrease its O&M spending. As a result, PGE would be unable to engage in certain activities and work that are currently a part of our present operations.

Q. What does PGE recommend of the Commission regarding AWEC's proposal?

A. PGE recommends the Commission reject AWEC's proposal and review the revenue requirement of this case based on the over 1,800 pages of testimony, exhibits, and workpapers provided by PGE to support its case.

B. Lack of Stakeholder Engagement on Critical Counterarguments

Q. Is it common for relevant information and key points to go unaddressed in a proceeding?

A. It is not unusual for some points made by PGE in reply testimony to go unaddressed, but in this instance, we find that there are a number of key points and positions going unaddressed. Of significant concern is the fact that some of PGE's most pertinent information and responsive data, directly addressing the positions of other parties, have been overlooked. We believe it is crucial to draw attention to this matter to ensure a thorough and balanced evaluation of all relevant facts and data presented by all parties involved.

Q. What relevant information provided by PGE in reply testimony to the Parties' positions that went unaddressed?

A. In their opening testimony, parties leveled strong criticism against PGE, alleging an apparent reluctance to accept "any" regulatory lag. This message has been echoed in news articles and other spaces. However, it is noteworthy that no party sought to verify, through formal discovery requests, whether PGE is indeed experiencing regulatory lag.

In response to these assertions, PGE presented evidence in its reply testimony demonstrating the extent of regulatory lag experienced. Specifically, we provide information showing that since January 2022, PGE has incurred over $150 million in lag for both the return of and return on investments that have been actively serving customers. That is $150 million that we would have otherwise collected as revenue but for regulatory lag. When considering that PGE’s 2023 annual net income was $228 million, the lag PGE has had to absorb is substantial.

Additionally, we disclosed that more than $100 million worth of capital assets, which were in service by the rate effective date of UE 416, were not factored into customer pricing in 2024. Furthermore, we emphasized that PGE's investment rate exceeds its depreciation rate, and that the company has already incurred $30 million in regulatory lag from January through June of 2024. This comprehensive data underscores the significant financial impact of regulatory lag on our operations, as evidenced by PGE 7.18% regulated ROE in 2023, and helps to provide understanding as to why PGE is unable to withstand more lag, as desired by the parties.

Yet, in their rebuttal testimony, no party responds to or recognizes the facts provided by PGE.

Q. Do you have other examples?

A. PGE identifies what has gone unaddressed by parties throughout our testimony. The only other item we will point out here is that we also noticed that in their efforts to continue to force a mid-year rate effective date through the use of an unconventional tracker, CUB did not address PGE’s point that the purpose of a tracker is to match the benefits experienced by customers with prices they are paying. CUB’s proposal essentially seeks to do the opposite. Without a convincing response to this point, PGE does not believe such a proposal can even be considered.

C. Overlapping Proposals

Q. In your reply testimony, you highlight the number of overlapping and/or duplicative proposals made by parties regarding operations and maintenance expense. What was the purpose of PGE highlighting this observation?

A. Given the complexity of this case, which encompasses over 100 distinct proposals, adjustments, and requests from various parties, it may be challenging for a new reviewer to easily observe the intersections of these positions. The multitude of overlapping perspectives and the significant financial implications necessitate a clear delineation of where these positions converge.

PGE considers it imperative to clarify these areas of overlap to mitigate the risk of inadvertent duplicative adjustments. We maintain our stance on the critical importance of avoiding such redundancies and affirm that Table 1 in PGE Exhibit 1000 serves as an appropriate and comprehensive guide for preventing such potential oversights.

This approach promotes accuracy in the review process, and safeguards against unintended financial consequences that could arise from overlapping adjustments. We believe this level of clarity is essential for a fair and thorough evaluation of the case, given its complexity and the substantial financial considerations involved.

VI. Outline of PGE Surrebuttal Testimony

Q. Please provide reference to other surrebuttal testimony PGE is submitting.

A. The following provides a high-level outline to PGE's reply testimony responding to issues raised in opening testimony by Staff and other parties:

Table 3
Outline of other testimonies

Exhibit	Summary
2200 – Capital Planning & Business Model	Witnesses Josh Kliever and Christopher Liddle continue their discussion on the cost-of-service model and regulatory lag. They address the Constable and Seaside trackers and CUB's proposal regarding PGE's rate effective date. They also address rate cap proposals made by parties. Finally, they discuss PGE's capital program and the efforts PGE takes to select appropriate and necessary investments each year to serve customers.
2300 – Affordability Programs and Proposals	Witnesses Kristen Sheeran, Jenn Latu, and Sam Newman address parties' rebuttal testimony on energy burden trends, including residential disconnections and arrearages levels. They respond to proposals made by parties related to affordability, PGE's income-qualified bill discount program, and procedural equity.
2400 – Revenue Requirement	Witnesses Greg Batzler and Stephanie Meeks address the rebuttal testimony of parties regarding multiple proposals impacting PGE's revenue requirement. Notably they address proposals to calculate PGE's rate base using either method that mismatches utility plant and depreciation, or one that uses an average over a historic test year.
2500 – Compensation and Corporate Support	Witnesses Anne Mersereau, Ryan Van Oostrum, and Greg Batzler speak to the continued need to address compensation holistically when addressing proposals made by parties. They also respond to proposals made regarding information technology investments, insurance and other topics related to administrative and general expenses.
2600 – Customer Service and Transportation Electrification	Witnesses Allison Rowden, Dain Nestel, and Elyssia Lawrence address the rebuttal testimony of parties related to proposed reductions to customer service and customer accounts. They also address rebuttal testimony Staff on transportation electrification.
2700 – Production	Witnesses Debbie Powell, Brian Clark, and Kori Mead address proposals made by the parties regarding non-labor generation expense, the Constable and Seaside battery energy storage projects, the diesel particulate filter project, and fleet replacement investments. They also address PGE's proposed tracking mechanisms for the Constable and Seaside projects.
2800 – Transmission and Distribution	Witnesses Kellie Cloud, Franco Albi, and Joey Baranski respond to parties' rebuttal testimony on proposals regarding T&D non-labor expense, including routine vegetation management, FITNES expenses, and virtual power plant. They also address proposals for three capital projects and T&D capital contingencies. Finally, they discuss PGE's January storm response.
2900 – Cost of Capital	Witness Josh Figueroa, a Brattle consultant specializing in return on equity, responds to the rebuttal testimony of parties regarding PGE's proposed ROE. Witness Christopher Liddle addresses PGE's capital structure and cost of debt.
3000 – Marginal Cost of Service	Witnesses Rob Macfarlane addresses proposals to alter PGE's generation and customer marginal cost of service studies.

3100 – Pricing	Witnesses Rob Macfarlane and Chris Pleasant present PGE's proposed prices changes by customer class. They also address parties' positions on the residential basic charge, commercial time of use, and the load following credit. They also address issues regarding rate spread and propose that net variable power costs remain in a separate schedule on an ongoing basis. Lastly, they address TE line extension allowances.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

Exhibit	**Description**
2101	IBEW Local 125 Filed Comments
2102	Operations and Maintenance Expense vs Inflation since 2019

IBEW Local 125

International Brotherhood of Electrical Workers

September 27, 2024

Oregon Public Utility Commission
201 High St., SE Suite 100
Salem, OR 97301

The International Brotherhood of Electrical Workers (IBEW) Local 125 represents approximately 4,000 members in the Pacific Northwest's construction and utility industry. We are writing to express our support for Portland General Electric Company's rate review request. We understand that most of PGE's request is to fund projects needed to strengthen their system and replace aging infrastructure. PGE's efforts will greatly accelerate the transition to cleaner generation and allow the crucial work of making the electrical grid more resilient to continue. IBEW members were frontline workers during the major winter storm last January and have seen firsthand how extreme weather events impact our communities. Due to the ever-increasing impacts of significant weather-related events, work needed to improve the system is imperative and should not be delayed. We are seeing events that used to occur every 50 or 100 years now occurring at an unprecedented pace. We understand that high inflation and rising costs across the economy have impacted everyone but would ask the Commission to not impair or delay needed work that is vital for a growing Oregon economy.

Our members take pride in the work that we do to keep the lights on for the millions of Oregonians who rely on us every day and to restore their power when disaster strikes. PGE's investments in building a grid that meets the needs of Oregonians relies on the skilled work of our members from the core of the business for more than 125 years of poles and wires to electric vehicle infrastructure that will support the modern grid of the future.

Members of IBEW Local 125 are Oregonians, many of whom are also customers of PGE and live within the communities they serve. A more resilient and reliable electrical grid is a key piece to solving some of the biggest threats to our communities while also insuring investments that are building the modern grid of the future, providing continued economic growth opportunities for the state. We urge your approval of PGE's request so this important work can continue.

Sincerely,

Travis Eri
Business Manager
IBEW Local 125

TE:cla
opeiu#11 afl-cio
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17200 N.E. Sacramento Street - Portland, Oregon 97230
Phone: (503) 262-9125 - Fax: (503) 262-9947

Test year	O&M $ in thousands	Total Increase since 2019
2019	562,050	
N/A		
N/A		
2022	565,261	0.6%
N/A		
2024	644,977	14.8%
2025*	701,301	24.8%

	All-Urban CPI	Total Inflation since 2019
2019		100.0
2020	1.2%	101.2
2021	4.5%	105.8
2022	7.4%	113.6
2023	4.0%	118.1
2024	3.2%	121.8
2025	2.2%	124.5

* Base Business O&M Request

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 435

Capital Planning and Business Model

PORTLAND GENERAL ELECTRIC COMPANY

Surrebuttal Testimony of

Christopher Liddle
Josh Kliever

October 1, 2024

Table of Contents

I. Introduction and Summary

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

A. My name is Christopher Liddle. My position is Senior Director, Risk Management and Assistant Treasurer at PGE. Our qualifications are included at the end of Exhibit 600.

My name is Josh Kliever. I am the Director of Financial Planning and Analysis at PGE.

We are adopting the testimony of Sheeran-Wise regarding Rate Caps from PGE Exhibit 1200.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to respond to concerns and proposals raised by the Staff of the Public Utility Commission of Oregon (Staff), the Citizens' Utility Board (CUB), and the Alliance of Western Energy Consumers (AWEC) (collectively, Parties) regarding:

1. The regulated utility model
    a. Cost-of-service ratemaking
    b. The role of regulatory lag
2. Related proposals
    a. Constable and Seaside trackers
    b. CUB's proposed tracker for a delayed rate-effective date
    c. Multi-year rate cases, and
    d. CUB and Staff's proposed rate caps
3. PGE's capital spending program

Despite extensive commentary on PGE's capital program, Parties have not identified any of the actual capital investments made by PGE on behalf of customers as imprudent, untimely, or unnecessary. In short, there is a notable desire to focus on the *outputs* of the ratemaking process, rather than the *inputs* that constitute PGE's cost to serve its customers.

Q. How does your discussion on cost-of-service ratemaking and the role of regulatory lag aid the conversation in this testimony?

A. Parties to this rate review have not fully addressed the basic principles of utility regulation. In particular, there appears to be a lack of emphasis on the importance of aligning prices with the actual costs of providing service to customers.[1] In our reply testimony, we provided detailed information about the various forms of regulatory lag and the significant effects it has on PGE. However, we notice that parties have not fully considered this information in their testimony, and they are continuing to request that PGE incur a growing and unreasonable amount of lag in addition to the regulatory lag PGE incurs each year. The departure from the traditional cost-of-service model and the exaggeration of PGE's capacity to withstand regulatory lag are evident in the proposals outlined in this testimony, which warrants discussion before addressing the proposals.

Q. Has PGE already addressed the cost-of-service model and regulatory lag?

A. Yes. PGE Exhibit 1100 provides a more detailed discussion of these two topics and includes illustrations of the various ways regulatory lag impacts utilities. We highly recommend a review of that testimony for a full understanding of PGE's perspective on this issue. In this testimony we will focus only on responding to the rebuttal testimony of Parties.

[1] CUB/400, Jenks/25-26.

Q. What proposals are you addressing?

A. We will address the following:

1. Staff recommends conditions to PGE's proposed Constable battery energy storage tracker while AWEC recommends rejecting the tracker.
2. Staff, AWEC, and CUB recommend against PGE's proposed tracker for Seaside battery energy storage.
3. CUB proposes a tracker to delay the implementation of the rate effective date by six months to impose regulatory lag on PGE.
4. Staff and CUB recommend the Commission convene a new independent investigation to explore multi-year rate cases.
5. CUB proposes a residential rate cap mechanism to limit annual rate increases, as an ongoing policy proposal. Staff proses a 3% rate cap on residential rates for this proceeding
6. CUB proposes a punitive adjustment of $10.8 million to employee incentive compensation related to PGE's future capital planning and spending.

Q. Please summarize PGE's response to these proposals.

A. PGE responds as follows to the proposals listed above:

1. PGE maintains its request to adopt Staff's proposal for the Constable tracker with a modification to the attestation deadline moving it from January 31, 2025 to February 28, 2025. We also maintain our position that the costs to be recovered for Constable should match the revenue requirement presented in this proceeding, and we support this position in PGE Exhibit 2800.
2. PGE requests that the Commission approve our request for a tracker for Seaside with the conditions we have offered. First, that PGE will provide evidence that capital

additions up to the in-service date of Seaside are indeed outpacing any depreciation offset, such that total rate base, excluding Seaside, is higher at its in-service date than at the beginning of the year. Second, PGE will provide an attestation, and third, the increase may only reflect the revenue requirement in this case as supported in PGE Exhibit 2800.

3. PGE requests the Commission reject CUB's proposal to move PGE's rate effective date by approximately six months to force the under recovery of approximately $95 million in 2025. Not only is this recommendation contrary to statute, as will be discussed in briefing, but the proposal fundamentally fails to align customer benefits and the prices they pay.

4. PGE does not believe it is necessary to open another investigatory docket on multi-year rate cases.

5. PGE requests that the Commission reject both Staff and CUB's proposals to impose rate caps on residential customer prices.

6. PGE requests that the Commission reject CUB's proposal to penalize PGE with a $10.8 million reduction in employee incentives for PGE's *future* capital spending program. Not only is their proposal unrelated to any element of this case, but CUB has failed to show that PGE is acting imprudently.

II. The Regulated Utility Model

A. Cost-of-Service

Q. What is your understanding of the basic principle for establishing rates in a general rate case?

A. Our understanding is that rates are set by "balanc[ing] the interests of the utility investor and the consumer in establishing fair and reasonable rates," which are amounts that provide "adequate revenue both for operating expenses of the public utility . . . and for capital costs of the utility[.]"[2] This ratemaking analysis requires a careful assessment of utility expenses to ensure that rates are based on a utility's cost-of-service.

Q. CUB continues to state that "[r]atemaking is about setting fair and reasonable rates, not cost recovery."[3] How do you respond?

A. CUB presents a false narrative. Fair and reasonable rates are set based on the cost of providing utility service. CUB focused on one-half of this statutory standard in its opening testimony[4] and ignored the second half. In reply testimony PGE explained that "just and reasonable" is a defined term according to the cost of providing service.[5] Thus, the establishment of just and reasonable rates is plainly tied to the recovery of prudently incurred capital costs. Indeed, CUB appears to recognize the centrality of cost-of-service in the rate-setting process by claiming that its proposals are purely based on "an analysis of PGE cost-of-service",[6] however CUB's proposals are quite contrary to these foundational principles. In sum, PGE notes the second half of the statutory standard, that establishing rates based on the prudent

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[2] ORS 756.040(1).
[3] CUB/400, Jenks/24 at 16-24.
[4] CUB/100, Jenks/4.
[5] PGE/1100, Kliever-Liddle/2 n.2, 27; PGE/1200, Sheeran-Wise/39.
[6] CUB/400, Jenks/32.

cost of providing safe and reliable service, is a necessary part of the regulatory compact in Oregon.

Q. CUB asserts that "the regulatory compact does not represent a fundamental principle of utility ratemaking[.]"[7] Do you agree?

A. No. CUB's assertion is based on an outdated comment letter by then-Senior Fellow Ari Peskoe, arguing that the regulatory compact is a "framing" tool that utilities use "to argue against competition and in favor of rate increases and cost recovery for investments that did not benefit ratepayers."[8] As an initial matter, the author of the letter quoted by CUB may be more known for discussions of the federal regulatory landscape, but even Professor Peskoe has recognized the critical importance of making investments *now*, and stated in a recent article, "Upgrades are imperative if we want consumers to enjoy the benefits of a modernized grid that would ultimately eclipse the initial cost of investment . . . these infrastructure needs are financed through utility bills."[9]

Moreover, this Commission has clearly and recently affirmed the regulatory compact in Oregon, explaining that "the regulated monopoly structure prevents the utility from denying service in high-risk locations of its franchised service territory or, alternatively, from earning the rate of return on capital investment that a competitive market might deliver for high-risk service. The monopoly utility must have its rates reviewed and approved by the regulator rather than rely on competition to result in fair and reasonable rates."[10] This succinct

[7] CUB/400, Jenks/25.
[8] Ari Peskoe, Summary of Comment: Utility Regulation Should Not Be Characterized as a "Regulatory Compact", Comment Letter to Quadrennial Energy Review Task Force, Office of Energy Policy and Systems Analysis (2016) (link unavailable).
[9] Ari Peskoe,"The Power to Change Power" Harvard Law Today, June 10, 2024.
[10] Order No. 24-155 at 6.

summation of the regulatory compact clearly elucidates how cost-of-service ratemaking links to utilities' obligations to serve.

Q. Do you have any overarching comments regarding the cost-of-service framework in this case?

A. We note that only CUB seeks to reject the central cost-of-service framework historically and consistently applied by this Commission in the exercise of its statutory duties. While we recognize that robust evaluation of utility costs in a general rate case requires considerable stakeholder time and attention, we appreciate other stakeholders' attempts to focus on the practical realities of other component costs of providing essential utility service, rather than retreating to speculative[11] generalities.[12] While we certainly disagree with some of the opinions and conclusions of other stakeholders in this case, we believe a more productive and efficient proceeding can be achieved when Parties concentrate on the actual cost drivers behind utility service.

Q. In PGE's assessment, has the primary focus in this case been on the cost drivers and a review of the prudence of PGE's capital projects and operating and maintenance expenses?

A. No. This case has been unusual in that the focus has been primarily on the percentage increase itself and not as much on the reasons for it. Efforts to explain why spending and capital investments are necessary and prudent in this case appears to be overshadowed by how much prices have changed over the past few years. This singular focus has lacked the context of how market-dictated power and fuel costs that are largely outside of PGE's control have nearly

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[11] E.g., CUB/400, Jenks/38-39 (stating "PGE will have to show that investing in transmission in North Dakota is necessary to serve customers[,]" despite the fact that this investment is not presented for review in this case).

[12] CUB/400, Jenks/39 ("CUB's approach in this case has been to look at PGE's overall approach to capital spending, not examine each individual investment[.]").

tripled in the last five years and are the primary driver of this change. The only solution offered regarding affordability is to essentially reject the cost-of-service model and any increase in prices without an thoughtful discussion of the ramifications of such a decision.

B. Regulatory Lag

Q. Please summarize the Parties' positions concerning regulatory lag in this case.

A. PGE understands regulatory lag as a part of the standard ratemaking process, whereby a utility recovers its previously approved rates until new reasonable rates are established in its next general rate case—even though costs change between rate cases.[13] Regulatory lag can have the impact of allowing a utility to either over- or under-recover on its investments depending on the pace the utility is investing in its system relative to accumulated depreciation. As explained in PGE Exhibit 1100, PGE is and has been experiencing significant under-recovery from regulatory lag for the past several years.

Staff and CUB, in particular, continue to believe that PGE is attempting to eliminate all regulatory lag and appear to believe that PGE is not experiencing considerable quantities of regulatory lag. PGE strongly disagrees and believes that excessive regulatory lag undermines our long-term ability to make crucially needed investments to meet growing demand and legislative mandates.

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[13] *See, e.g.,* Docket UE 394, Order No. 22-129 at 35 ("Under our standard ratemaking process, PGE will have the opportunity to recover a return of and a return on the plant balances included in rate base until its next rate case, even as the value of those assets depreciates and plant is retired. The benefit of continuing to collect rates on the rate base established in the prior rate case is countered by the ongoing capital investments a utility makes that will not be placed into rates during that period.").

Q. Do Staff and CUB demonstrate a comprehensive and accurate understanding of the complexities of regulatory lag in their statements?

A. No. Both Staff and CUB continue to show only a one-sided understanding of regulatory lag that is disconnected from the circumstances PGE is currently facing. As explained below, Staff even misunderstands their own citation to a 2015 presentation, which actually supports the points PGE has made. CUB downplays the amount of lag that their proposals introduce by referring to it as "some regulatory lag"[14] and "a little regulatory lag."[15] PGE provided an extensive, multi-sided explanation of regulatory lag complete with charts showing the various ways the two sides of regulatory lag can impact each other under various circumstances.[16] We identified that the final chart was representative of PGE's current situation. This is supported by the values PGE provided showing the ongoing occurrence of significant amounts of regulatory lag. No party disputed PGE's illustrations or interpretations of regulatory lag.

Q. How did Parties respond to PGE's discussion of the difference between acceptable and unacceptable regulatory lag?[17]

A. Parties did not address PGE's discussion. This discussion explained that when new investments far outpace the offsetting depreciation on existing rate base, the regulatory lag can jeopardize PGE's financial health, its credit rating, and its ability to attract future capital. We also provided evidence from the financial community supporting our assessment.

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[14] CUB/400, Jenks/25 at 9.
[15] CUB/400, Jenks/27 at 15.
[16] PGE Exhibit 1100 at 28-30.
[17] PGE Exhibit 1100 at 26-27.

Q. In the discovery phase of this proceeding, did any party submit a request for information to understand the full extent of regulatory lag experienced by PGE in recent years prior to claiming that PGE is unwilling to accept any regulatory lag?

A. No.

Q. How did Staff and CUB respond to the data provided by PGE illustrating that PGE has incurred over $150 million[18] of regulatory lag for in-service assets that were not in customer prices since January 2022?

A. Staff did not address this information, yet they continued to make statements in testimony that PGE is unwilling to experience regulatory lag.[19]

CUB submitted a data request to PGE seeking clarification on the components of PGE's identified regulatory lag. Specifically, CUB inquired whether the reported regulatory lag value accounted for both capital-related increases and decreases. In response, PGE confirmed that the provided value already incorporated both aspects of regulatory lag in its calculation. CUB did not include any reference to their data request or any dialog recognizing the information provided by PGE.

Q. PGE presented two other significant data points regarding regulatory lag: 1) $100 million of assets began serving customers prior to PGE's last rate effective date, yet were not incorporated into customer prices, and 2) $30 million of return on and return of lag has been incurred in just the first six months of 2024. Given the Parties' prior comments on regulatory lag, how did they respond to this information?

A. No party addressed these data points in their rebuttal testimony.

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[18] Represents the return on and of rate base not in customer prices each month since January 2022. Rate base includes the total plant in-service *net of* accumulated depreciation.

[19] Staff/2300, Dlouhy-Scala/6 at 20-21.

Q. In rebuttal testimony, despite the above-mentioned data points PGE provided, Staff claims that PGE has a "lack of tolerance for regulatory lag[.]"[20] How do you respond?

A. The continued insistence on this perspective ignores the factual evidence PGE provided on the amount of regulatory lag that we have and will continue to experience in the near term. This lag remains significant even if a tracking mechanism for the Seaside battery project is approved. Our data clearly demonstrates the ongoing financial impact of regulatory lag on our operations, regardless of potential adjustments for specific projects.

Q. Staff now asserts that "regulatory lag is only 'bad' for inefficient utilities," pointing to a 2015 presentation by a Louisiana University Professor, David E. Dismukes, Ph.D.[21] Do you agree?

A. No—and neither does the expert Staff cites. As Dr. Dismukes' presentation stated, the significance of regulatory lag is tied to the relative demand growth and infrastructure investment needs of the time. When his presentation was issued in 2015, regulatory lag held "less merit" given the "low energy demand growth and infrastructure replacement challenges."[22] Yet in today's "high growth/high productivity environment," regulatory lag "[h]inders infrastructure development, capital expenditures and investment in 'non-revenue generating' system improvements (i.e., safety, reliability, resiliency)."[23]

[20] Staff/2300, Dlouhy – Scala/6.
[21] Staff/2300, Dlouhy – Scala/8.
[22] Staff/2301, Dlouhy/17.
[23] Staff/2301, Dlouhy/17.

Q. CUB asserts that PGE "avoid[s] regulatory lag with all of its large investments" through the use of trackers.[24] Is this correct?

A. No. CUB's expansive statement is obviously undercut by the amount of PGE's actual regulatory lag identified. PGE's largest investments over the past five years have been the cumulative investments in transmission and distribution, and there is no path to recover these types of investments without a rate case.

Q. Ultimately, how have the Parties' continued assertions regarding regulatory lag impacted their positions in this case?

A. By perpetuating the incorrect narrative that PGE is unwilling to accept any regulatory lag, Parties can reinforce their positions against allowing a tracking mechanism for the Seaside project, and CUB can continue to support their argument for a six-month delay in PGE's rate effective date. Furthermore, this characterization seems to serve as a basis for opposing any mechanisms, now or in the future, that would incorporate capital investments into customer prices between rate cases, even if its purpose is to delay the need for additional rate cases.

Q. Does PGE have anything else to add regarding this topic?

A. In a proceeding where PGE's transparency has been called into question,[25] we find it particularly challenging that, even when presented with clear evidence that PGE experiences ongoing and significant amounts of regulatory lag, certain parties appear to disregard the data and evidence provided. This selective interpretation of information seems to persist in order to maintain a narrative that supports their arguments. We are concerned that this approach may prioritize maintaining previously held positions over objectively assessing new

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[24] CUB/400, Jenks/31.
[25] Staff/2300, Scala-Doulhy/3 at 15-17.

information, potentially at the expense of a fair and accurate representation of PGE's financial situation.

III. Related Cost Recovery Proposals

A. Constable and Seaside Trackers

Q. Please briefly summarize PGE's proposed trackers for the Constable and Seaside battery energy storage projects.

A. PGE proposed to track and incorporate the full revenue requirement impacts of the Constable and Seaside projects through updates to the cost-of-service rate schedules in the same manner as the rest of PGE's generation revenue requirement.[26] The Constable project is anticipated to be online and serving customers by the end of this year, making this a precautionary proposal, while the Seaside project is targeted to be online in mid-2025. These tracking mechanisms are designed to ensure appropriate alignment between the substantial benefits of these major projects and the prices charged to customers.

Q. Where do the Parties stand regarding the Constable tracker?

A. In opening testimony, Staff found the use of a Constable tracker acceptable provided three conditions: (1) that PGE provide an in-service attestation, (2) that Constable is placed in-service by January 31, 2025, and (3) that the gross plant included in customer prices constitute the lesser of $143 million or actual gross plant.[27]

PGE responded in reply testimony by altering the conditions as follows: (1) that PGE provide an in-service attestation, and (2) that Constable is placed in-service by February 28, 2025. PGE does not agree to the third term which shows a lack of understanding of the RFP scoring process relative to the actual costs associated with a project, as discussed in PGE Exhibit 2800.

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[26] PGE/900, Macfarlane-Pleasant/11.
[27] Staff/1700, Dlouhy/22.

At this time, Staff continues to prefer all elements of their own proposal. AWEC continues to argue that no tracker is needed or appropriate for Constable. CUB has updated their position and states that they support Staff's proposal for the Constable tracker.

Q. How does PGE respond to Staff regarding the Constable tracker date?

A. PGE continues to find its own proposal regarding the Constable tracker to be fair and reasonable as well as consistent with prior treatment by Parties. PGE's proposed deadline for the plant to be in-service of February 28, 2025, is reflective of the approximately two-month window that was most recently used for tracking in a major asset for PGE.[28]

Q. Does AWEC provide any new arguments regarding why PGE should not be allowed a Constable tracker?

A. AWEC now asserts that if PGE had concerns regarding the timing of the project, we should have delayed our rate case filing by one month to provide a buffer for the Constable plant's integration, and they ambiguously comment that PGE's request for an additional month on the deadline for attestation to be "telling."[29]

Q. How does PGE address AWEC's suggestion that we could easily just adjust our rate effective date?

A. As demonstrated in PGE Exhibit 1100, PGE has consistently filed rate cases on a calendar timeline with a January 1 rate effective date for over three decades. This practice has not been challenged in any previous rate case. However, in the current proceeding, multiple parties have suddenly suggested that PGE can easily decouple its entire budgeting and financial planning process from the timing of new customer rates. While we are willing to take on the

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[28] In the Matter of Portland General Electric Company Request for a General Rate Revision, Docket UE 294, First Partial Stipulation at 5 (Jun. 23, 2015).

[29] AWEC/300, Mullins/44 at 3.

challenge of attempting to make this shift in the future, we find this suggestion to be unreasonable and impractical in the middle of a rate case filing.

While we anticipate that the Constable project will be operational by the end of 2024 as planned, we believe it is prudent to allow for the timely inclusion of this major asset in customer rates, given its significant size and the value it will provide to customers. AWEC's opposition to this approach and their suggestion that PGE should potentially incur more than a year's worth of regulatory lag on an asset valued at over $157 million, in our view, is unreasonable and fails to consider the financial implications and operational realities of such a significant investment.

Q. How does PGE respond to AWEC's statement that PGE's proposed deadline for Constable of February 28, 2025 is "telling."

A. Given the ambiguity in AWEC's statement, our response is necessarily limited. However, we repeat that our selection of a date two months beyond the initial expected in-service date is consistent with prior practices for selecting a deadline on a tracker attestation. This approach simply provides PGE additional assurances against unforeseen circumstances while being in line with prior practices.

Q. Did PGE alter its proposal for the Seaside tracker in reply testimony?

A. Yes. In PGE Exhibit 1700, PGE proffered conditions for allowing the Seaside tracker. First, to prove the accuracy of our statements regarding regulatory lag in times of significant growth, PGE offered additional detail regarding all capital net of accumulated depreciation up to the rate effective date of Seaside to show that customers will not be overpaying. Essentially, we will show that PGE will be incurring ongoing regulatory lag on all of our other assets through 2025, making the significant lag associated with Seaside excessive and financially harmful.

Second, we offered to agree that only the revenue requirement included in this case be included in customer prices. This is the revenue requirement consistent with PGE's position in PGE Exhibit 2800. We also offer to provide an attestation once the plant is serving customers.

Q. How did Parties respond to PGE's proposed tracking mechanism for Seaside in rebuttal testimony?

A. Staff rejects the Seaside tracker by stating that PGE should have delayed its rate case or rate effective date to include Seaside, and states that regulatory lag is "a useful feature of a regulated industry."

AWEC's position is similar to Staff's in that they outright reject PGE's Seaside tracker. In rebuttal testimony, AWEC maintains its claim that this tracker is "single-issue ratemaking and [is] inconsistent with Oregon's used and useful requirements."[30]

CUB also similarly argues against the Seaside tracker as being single-issue ratemaking. They argue that PGE should have timed its rate case to include Seaside without a tracker, and states that for this reason PGE's regulatory lag arguments should be disregarded. PGE will address CUB's proposal in Section B.

Q. How did Parties' respond to PGE's proposed conditions to the Seaside tracker?

A. No Party addressed any of the proposed conditions.

Q. How does PGE respond to Staff's position that regulatory lag is "a useful feature of a regulated industry[?]"[31]

A. It appears that Staff's statement is premised on the 2015 presentation that they provided in Staff Exhibit 2300. As explained above, Staff misrepresents the key points of this presentation,

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[30] AWEC/300, Mullins/43.
[31] Staff/2400, Dlouhy/17 at 14-15.

which actually explains that regulatory lag is damaging in "high growth/high productivity environment[s]" consistent with the one we are in today.

Q. How does PGE respond to AWEC's assertion that a tracker is inconsistent with Oregon's used and useful requirements?

A. While we are not attorneys, our understanding of the "used and useful" standard is that it permits only assets actively serving customers to be included in customer rates. PGE's proposal aligns the in-service date of the asset with the date customers would begin paying for it. As such, we disagree fundamentally with AWEC's position.

Q. How did AWEC address PGE's response regarding the Carty project that because of the structure of the tracker, customers did not pay beyond the initial revenue requirement?

A. AWEC did not address any of PGE's responsive testimony regarding Carty. Specifically, that the challenges with Carty stemmed from the credit metrics of the bidding party on the project,[32] a situation that is not present here, and that while the Carty project itself experienced challenges that led to significant cost overruns, none of those costs were included in customer prices because of the tracker.

Q. Is there anything else PGE would like to address regarding the correlation between PGE's proposal in this case and Carty?

A. Carty represents the last time PGE had a major plant coming into service mid-year that would not be subject to the renewable adjustment clause. The Parties to the case, which included CUB and ICNU,[33] agreed that a tracker that reflected the revenue requirement of the project with an in-service deadline approximately two and a half months after the targeted in-service

[32] We reiterate that Carty was not a benchmark bid submitted by PGE.
[33] ICNU - Industrial Customers of Northwest Utilities, now named AWEC.

date was appropriate, and no one argued that PGE should have timed the 2016 rate review with the in-service date of the project. Further, because of the tracker, none of the cost overruns were included in customer prices.

In this case, PGE has two major plants coming into service: one at the end of 2024 and one in mid-2025, as well as a significant amount of plant-in-service by the end of 2024 which represents nearly three times the rate base of the mid-year project, and yet Parties are arguing that PGE should have – for the first time ever – timed this rate review to coincide with the mid-year project. Further, PGE has proposed similar conditions as those supported by the Parties in the case of Carty – that we file an attestation of in-service and that only the revenue requirement in this rate review be allowed into customer prices. And we have offered the additional condition to show that all other capital spending is outpacing depreciation in 2025, and that if it is not, we would forgo the tracker.

Q. How does PGE respond to Staff's assertion that PGE would only need to absorb $10 million of associated regulatory lag if we had delayed our effective date to align with the Seaside project?[34]

A. Staff is only speaking to the regulatory lag that would have been experienced on the Constable project which is not the totality of the regulatory lag that PGE would incur if forced to a mid-year effective date. As noted in our discussion on CUB's request to delay PGE's rate effective date, a six-month delay on PGE's total revenue requirement increase would constitute a $95 million[35] shortfall of revenue in 2025 for PGE. This drastically differs from the isolated $10 million lag on Constable that is cited by Staff.

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[34] Staff/2400, Dlouhy/17 at 18-19.
[35] This is equal half of the $189.8 million revenue increase PGE is seeking in this proceeding excluding Clearwater, which remains a part of the renewable adjustment clause deferral until included in customer prices.

Q. What actions will PGE take if the Seaside tracker is denied?

A. PGE has few options for addressing the significant amount of regulatory lag that would be presented by Seaside in addition to the growing annual lag we are experiencing by investing in assets at a rate that outpaces depreciation. PGE would either need to file another rate case promptly to ensure timely cost recovery or adjust the utilization of the plant to reflect the fact that its costs are not currently being recovered from customers. This latter treatment would be consistent with the terms of the stipulation filed September 26, 2024 within Docket UE 436. Both options present challenges and require careful consideration to balance the company's financial health with our commitment to providing reliable service to our customers.

Q. What is PGE's recommendation to the Commission regarding the Constable and Seaside trackers?

A. PGE recommends that the Commission allow the Seaside tracker as a fair method for PGE to manage against regulatory lag while ensuring that customers do not overpay.

B. CUB's Tracker

Q. CUB proposes to delay the rate effective date in this case by approximately six months by "plac[ing] the revenue requirement increase into the [Seaside] tracker" so the combined rate effects will take place on June 30, 2025.[36] Is this an appropriate tool to address affordability?

A. No. As we explained in reply testimony, delaying recovery of prudently incurred costs is contrary to the cost-of-service regulatory paradigm and the statutorily-prescribed general rate case schedule. Furthermore, we reiterate this tool is not a tracker, as a tracker's design is meant to ensure a matching between benefits experienced by customers with the prices that they pay.

[36] CUB/100, Jenks/11.

Q. How did CUB respond to the fact that their "tracker" does not align with the central purpose of a tracking mechanism because it fails to match customer benefits with the prices paid?[37]

A. CUB did not respond to this point.

Q. CUB now claims that delaying the rate effective date would not subject "all of PGE's incremental investment" to regulatory lag.[38] Please explain.

A. CUB's position on this issue is unclear. Delaying the rate effective date by approximately six months would plainly result in six months' worth of foregone cost recovery—particularly since CUB has certainly not proposed to apply carrying charges to PGE's revenue requirement amount. Rather, CUB merely asserts that PGE should be subject to "a little" lag on its investments.[39]

Q. How do you respond to CUB's proposed delayed rate effective date?

A. In addition to the concerns we highlighted in reply testimony, there are three problems with CUB's characterization of its "tracker": First, what CUB describes as "a little" lag would in fact amount to approximately *$95 million* in under-recovery, if the rate effective date is delayed to July 1. If the rate effective date is delayed to CUB's alternative April 1 date, the Company would still experience a cost recovery shortfall of approximately $48 million. Second, ORS 757.215(1) provides guardrails around the amount of regulatory lag following a utility cost recovery request by establishing the nine-month cap on new tariff suspensions. Third, what CUB describes is not truly regulatory lag—it is asking the Commission to

[37] PGE/1100, Kliever-Liddle/35.
[38] CUB/400, Jenks/29.
[39] CUB/400, Jenks/27.

determine just and reasonable rates for a 2025 test year, and then to set rates *below* that level for a specified period of time.

Q. CUB argues that PGE can simply "manage their costs and their investments" to avoid negative impacts of CUB's proposed approach.[40] Do you agree?

A. No. CUB ignores the fact that PGE's costs are driven by the need to meet legislative mandates and regulatory requirements. As illustrated in PGE Exhibit 2100, PGE has maintained its operating expenses for several years below inflation as we have been asked to do more to serve customers and regulatory obligations. For PGE to "manage its costs and investments" as suggested is a call for PGE to reduce its efforts to support customers and to achieve the goals of the clean energy transition.

Q. Are these under-recovered amounts simple and easy to absorb?

A. No. PGE must cover its cost to deliver power and PGE must service its debt and equity on the investments that have already been made. This means that the only way for PGE to address such a shortfall would be through the reduction of operating expense. However, as PGE has shown in its overview testimony and amply demonstrated in this case, operational spending is already significantly constrained. As shown in Exhibit 2100, PGE's request in this case would bring PGE in line with inflation since 2019. Thus, significant reductions in operational spending to absorb CUB's under-recovery proposal would significantly hamper PGE's ability to maintain its current level of service.

Q. You previously noted the technical difficulties with modifying PGE's financial planning models to correspond to a non-calendar year rate case approach.[41] How did CUB respond?

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[40] CUB/400, Jenks/27.
[41] PGE/100, Kliever-Liddle/33.

A. CUB largely dismissed our concerns and noted that Idaho Power and other utilities use a rate effective date other than the beginning of the calendar year.[42]

Q. Has CUB presented a viable basis for changing the rate effective date in this case?

A. No. PGE has no insight into the internal administrative processes that other utilities may use to structure their rate case and financial systems. Furthermore, Idaho would have anticipated the timing of their case within their financial models, whereas CUB is insisting that PGE accept a substantial delay in revenue for which we have not planned.

While PGE remains ready and willing to explore options for the timing of future rate cases based on the practical realities of PGE's systems, we do not believe that simply delaying our rate effective date is a viable solution without accounting for the costs of such a delay.

Q. Does PGE have an alternative proposal for the Commission for this case?

A. As an alternative to a January 1, 2025 rate effective date, PGE is open to the Commission allowing PGE the full recovery of its approved 2025 test year revenue requirement to be spread from April 1, 2025 to December 31, 2025. This will result in a decrease in base rates to the annualized 2025 revenue requirement come January 1, 2026.

C. Multi-Year Rate Cases

Q. Please summarize PGE's position regarding exploration of multi-year rate cases.

A. Based on feedback from other Parties in this proceeding, PGE has agreed to withdraw its request for an investment recovery mechanism (IRM), and instead will seek to pursue a multi-year rate case through conversations with stakeholders. PGE is not advancing a specific multi-year rate case proposal in this proceeding.

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[42] CUB/400, Jenks/31.

Q. How do other Parties respond to PGE's intent to explore a multi-year rate case in the future?

A. Staff and CUB state that the Commission would need to convene a new independent investigation in order to explore multi-year rate cases before either party would be willing to consider a utility-specific multi-year rate case proposal.[43] Staff states that establishing a multi-year rate plan through a traditional general rate case proceeding "would not be constructive given the statutory timelines set by a rate case."[44] CUB argues that any multi-year rate case mechanism must be the result of a separate investigation, on the basis that simultaneous review in a GRC proceeding would be too challenging for stakeholders.[45]

Q. Do you agree that convening a new investigation is necessary or more efficient for stakeholders?

A. No. It is unclear how opening another independent investigation will streamline the participation process for stakeholders, particularly when the specifics of any multi-year rate plan would still need to be tailored to individual utility circumstances. Indeed, CUB itself asserts that "there is not room on the agenda for an investigation" of this type.[46] PGE looks forward to collaborating with parties to identify the most efficient process for considering possible future multi-year rate plan options.

Q. What is PGE's recommendation concerning multi-year rate cases in this proceeding?

A. PGE recommends that the Commission decline to convene a new investigation into multi-year rate cases, and instead reaffirm the Commission's willingness to flexibly consider utility-specific proposals as they may arise. PGE believes that yet another investigation would not

[43] Staff/3000, Stevens/33; CUB/400, Jenks/50.
[44] Staff/3000, Stevens/34.
[45] CUB/400, Jenks/50.
[46] CUB/400, Jenks/50.

be an efficient use of parties' time and resources. To the extent that PGE and stakeholders are able and willing to design a multi-year rate plan that would reduce the administrative burden on all parties and represent a reasonable settlement of contested issues, PGE believes that the Commission can and should retain the flexibility to consider such a proposal on a case-by-case basis.

D. Rate Caps

Q. Please summarize Parties' residential rate cap proposals.

A. CUB and Staff both make rate cap proposals:

1. CUB proposes limiting residential rate increases such that if rates increase above ten percent or seven percent plus CPI, then the Commission should "require application of tools to mitigate that shock"—namely, (1) deferring/phasing in rate increases; (2) setting rates at the lowest reasonable rate; and (3) requiring the utility to propose and implement other unspecified rate mitigation measures.[47] This policy proposal would apply to future years and proceedings.
2. Staff proposes some combination of revenue requirement reductions and rate spread design, so that "the residential class" should experience "an increase of no more than three percent of revenue requirement."[48]

Q. Please summarize PGE's position regarding Staff and CUB's rate cap proposals.

A. PGE's overarching concern with the rate cap proposals is that these caps deny cost recovery for prudently incurred costs, which is inconsistent with cost-of-service regulatory framework and the setting of fair and reasonable rates established in ORS 756.040. Based on prior Commission decision, addressing rate shock is not appropriate in the determination of a

[47] CUB/100, Jenks/72-73, 75.
[48] Staff/200, Scala/38.

utility's revenue requirement.[49] To the extent, as proposed by Staff, rate spread is used to address a single customer class rate cap, a rate cap could be effectuated, but again challenges cost causation principles, increasing uncertainty for non-residential customer prices. Lastly, there are several drawbacks in practice to implementing rate caps, such as those proposed by Staff and CUB. Rate caps could delay necessary investments in infrastructure and maintenance, leading to higher costs in the future. Artificial caps on rates can distort market signals leading to lower priority on energy efficiency. Caps would also limit the available revenue needed to maintain and upgrade the system, potentially compromising service quality and reliability.

Q. How did Staff respond to PGE's point that the value of three percent (or eight percent in another utility proceeding) is unsupported?

A. Staff did not address PGE's point that the three percent cap (or eight percent in the case of PacifiCorp UE 433) is arbitrary. Staff rebuttal testimony contains very little on cost cap proposals aside from Staff/2300 where Staff describes, but does not indicate support, for CUB's rate cap proposal. Staff agrees with PGE that the Commission has flexibility to structure customer class rate spread and Staff also acknowledges rate caps and thresholds could delay important investments.[50]

Q. How does Staff respond to PGE's other points such as denying prudently incurred costs and the more practical impacts for customers?

A. Staff does not address PGE's points.

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[49] *In the Matter of Portland General Electric Company's Proposal to Reprice its Service in Accordance with the Provisions of SB 1149*, Docket UE 115, Order 01-842 at 4 (Sep 28, 2001).
[50] Staff/200, Dlouhy-Scala/6 at 13 to 15.

Q. How does CUB address PGE's reply testimony that rate caps could limit recovery of prudent investments?

A. CUB dismisses PGE's position that rate caps could limit needed investments and limit cost recovery of prudent investments allowed under ORS 756.040. Rather CUB states a "rate cap might just delay small amounts of capital recovery."[51]

Q. What is PGE's response to CUB's argument that a rate cap is only a small delay?

A. A delay in cost recovery is denying cost recovery for prudently incurred costs. Delaying recovery shifts the rate impact to customers further pancaking future rate changes and distorting customer price signals and limits revenue and cash flow needed by the utility to maintain and upgrade the system.

Q. How does CUB respond to PGE's argument that a rate cap is inconsistent with statutory requirements to set fair and reasonable rates?

A. CUB disagrees and says they will address this in their opening brief. CUB indicates their proposal is consistent with the existing authority of the Commission, as previous Commissioner Beyer testified in front of the Oregon legislature in 2003. CUB omits that Commissioner Beyer also testified that the Commission was "not wildly enthusiastic about this bill" and did not "see a need for it,"[52] presumably given the Commission's established authority to take certain measures.

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[51] CUB/400, Jenks/

[52] CUB/103 Jenks/1; Testimony of Lee Beyer, Commissioner Oregon Public Utility Commission, Before the House Committee on Business, Labor & Consumer Affairs, HB3575, (Apr. 14, 2003).

Q. CUB suggests the costs exceeding the rate cap could be managed to stay below, or else only have a small delay if costs do go over.

A. By suggesting the utility manage operations and make decisions to keep costs below the cap if one were imposed, CUB is supporting PGE's position that a possible impact of a rate cap is to delay necessary capital projects. Limiting capital would reduce our ability to deliver outcomes for customers as we have aging infrastructure needs, new customer and system growth investments and decarbonization goals.

Q. Please elaborate on why PGE believes a rate cap could limit and delay necessary investment.

A. In a rising cost and high investment-needs environment, a rate cap sets a limit on the timely recovery of prudently incurred costs. A situation where this could chill investment might be during high power costs or another external driver that pushes an annual price increase to the cap. Knowing there is a cap could then lead to cutting of planned capital projects.

Q. How does CUB address the potential financial impacts of a rate cap?

A. CUB does not directly address the financial impacts that could occur from adoption of a rate cap in the state of Oregon. CUB does minimize and downplay any consequences. CUB says whatever revenue not collected from the cap "is a small amount, that PGE could collect later" or a "limited amount of regulatory lag could occur". Even if PGE were to collect the delay in revenue through a deferral, this would place financial burden on the utility balance sheet, further impacting credit ratios beyond the nearly $250 million already leveraging PGE's balance sheet.

Q. What is Verde's position on a residential price cap?

A. Verde supports Staff and CUB's respective rate cap proposals.

Q. Why does Verde support these rate caps?

A. Verde believes both caps will relieve energy burdens and Verde supports CUB's proposal because it "helps avoid the need for energy advocates to intervene in rate cases".[53]

Q. How does PGE respond to Verde's position on the rate cap proposals?

A. It seems speculative whether energy advocates would intervene less under CUB's ten percent rate cap proposal. Verde's position that IQBD design, and affordability proposals be addressed in general rate case proceedings seems contradictory to the position that energy advocates would intervene less, since energy advocates would intervene to be part of those discussions on mechanisms regardless of if the overall rate increase was capped.

Q. What is PGE's recommendation concerning Staff's rate cap proposal for this proceeding and CUB's rate cap mechanism?

A. PGE recommends that the Commission reject Staff and CUB's rate cap proposals and proceed with the matters of this rate case and future rate cases following established statutes for setting fair and reasonable rates. PGE asks the Commission to encourage Parties to establish affordability mitigants in relevant dockets such as UM 2211.

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[53] Verde/200, Segovia Rodriguez/13.

IV. Capital Planning and Spending

Q. Please summarize CUB's position regarding PGE's capital planning and spending program.

A. In rebuttal testimony, CUB maintains its position that PGE's overall capital investment strategy lacks appropriate prioritization and fails to adequately constrain capital expenditures.

Q. What does CUB propose given their position?

A. While CUB has raised concerns about PGE's capital spending practices, it is worth noting that their critique does not include specific recommendations for rate base adjustments. Instead, CUB persists with its alternative approach, focusing not on PGE's actual costs but on speculative forecasts of future investment levels. Notably, these projections do not account for offsetting accumulated depreciation over the period despite CUB's own testimony on regulatory lag emphasizing the importance of considering all elements. Consequently, CUB continues to advocate for a $10.8 million reduction in PGE's employee incentive compensation within this current rate review, which is disconnected from the actual prudent spending of the projects included in this case.

Q. How did CUB respond to PGE's reply testimony regarding capital spending, planning and oversight?

A. CUB's rebuttal broadly dismisses much of the comprehensive and responsive testimony provided by PGE, which outlines our robust processes, controls, and methodologies for budgeting, planning, and managing capital expenditures. To ensure a thorough understanding of the matter, we strongly encourage all parties reviewing this testimony to also examine PGE Exhibit 211 and PGE Exhibit 1100, which both provide a more complete and balanced perspective on our capital management practices.

Q. How did CUB respond to PGE's point that CUB has not identified or discussed any capital investment in this case that is imprudent, premature, or unneeded?

A. CUB responded to this point by saying that their purpose was to examine PGE's overall approach to capital spending, and that they were too "overwhelmed"[54] to be able to review individual projects. As such, PGE remains uncertain as to what investments CUB believes PGE should be prioritizing, as we see the investments we are making as all necessary for safety, compliance, reliability, customer growth and future renewable integration.

Q. What issues does CUB highlight in their rebuttal testimony?

A. CUB maintains that:

- PGE does not hold capital spending to reasonable escalations.[55]
- Replacing delayed investments with new projects to maintain target spending shows a lack of cost control.[56]
- PGE provided little evidence to show that project controls and governance are effective in keeping investments within budget.[57]
- PGE has done little to address affordability.[58]
- Investment levels are set for investor perception.[59]

CUB bases many of these claims on their analysis of information obtained through discovery. They contend that this information reveals discrepancies between PGE's reply testimony statements and the evidence they reviewed.[60]

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[54] CUB/400, Jenks/39.
[55] CUB/400, Jenks/36.
[56] *Id.*
[57] *Id.,* Jenks/40.
[58] *Id.*, Jenks/43.
[59] *Id.*
[60] *Id.,* Jenks/40.

Q. How does PGE respond to CUB's position that PGE's capital spending is not held to a reasonable escalation?

A. We disagree. PGE determines its capital investment targets through a comprehensive planning process that aligns with its strategic goals, regulatory requirements, and operational needs. These targets are carefully set based on several key factors: customer demand and load growth, potential customer impact, financial constraints, stakeholder input, and opportunities presented by technological advancements and innovation. This thorough approach ensures that PGE's capital spending balances multiple priorities to best serve its customers.

CUB highlights that in 2019, PGE's capital target was $500 million and that target increased to $1.2 billion by February 2023. Those target amounts are correct but what CUB fails to highlight is the initial target was set five years in advance without consideration of unknown investment impacts from the COVID-19 pandemic, investments needed to comply with House Bill (HB) 2021, increased investment for Wildfire Mitigation, increased inflation, and significant customer growth in the data center and semiconductor sectors.

Q. To support their position, CUB cited that PGE increased its spending from 2022 to 2023 which increased by $580 million. If this occurred, what was the reason?

A. PGE increased its actual spend from $790 million in 2022 to $1,370 million in 2023, a $580 million increase due primarily to new large projects, which were the outcome of RFP processes. The majority of the increase (approximately 71% of the $580 million) is related to Clearwater, which is a project that helps PGE achieve HB 2021 goals and is resulting in a price decrease to customers. Another 21% of the increase is for the Constable and Seaside batteries, which also support PGE's need to increase clean capacity to reliably meet customer power needs. CUB did not inquire about the reason for the increase in discovery.

Table 1
Capital Expenditure Increase from 2022 to 2023

Project Driver	Increase Amount 2022 to 2023 (in millions)	Share of Increase (as a Percentage)
Clearwater Wind	$ 411	71%
Constable Battery	$ 34	6%
Seaside Battery	$ 90	16%
Evergreen Substation	$ 75	13%
Other, net	$ (30)	-5%
Total	**$ 580**	**100%**

As shown by the projects listed in Table 1, and as described previously, 2023 capital targets increased but so have the benefits to customers to meet decarbonization goals, increase reliability, decrease wildfire risk, and increased capacity to support economic growth in PGE's service territory.

Q. How does PGE respond to CUB's continued position that replacing a project that needs to be delayed with another project contradicts the notion that PGE delays investments for as long as possible?[61]

A. CUB maintains its broad assertion without recognition of PGE's reply testimony which explained that, within the area of distribution system spending in particular, there is a long backlog of necessary, customer-driven projects. PGE's capital review cycle is continually seeing higher demand for prudent and high-priority capital investments that can be fit into capital targets each year. Therefore, if an approved project must be delayed, it would be inattentive to the needs of our customers to underrun the annual capital planning budget in total.

[61] CUB/400, Jenks/36 at 19.

Q. CUB claims the evidence they reviewed in discovery shows a disconnect to PGE's statements in reply testimony. What did they find?

A. In a review of the documentation showing monthly projects submitted to PGE's Capital Review Group (CRG) CUB determined that:

- The CRG **[BEGIN CONFIDENTIAL]** [redacted]
- [redacted]
- [redacted]

[END CONFIDENTIAL] [62]

CUB implies that the CRG does not reject enough projects, and therefore, by extension, CUB is explicitly[63] saying that this is evidence that PGE is not controlling its costs.

Q. Does PGE agree with CUB's analysis of PGE's discovery responses?

A. No. To address the first point, the monthly CRG documentation is for projects already in progress and does not encompass every project considered by PGE. Before reaching the official submission stage, projects undergo various informal evaluations. Many ideas are verbally proposed and discussed in meetings, with non-viable options being eliminated early to save time and resources. This ensures that only the most promising projects advance to formal consideration. In essence, CUB's review of the monthly CRG documentation captures only the final approval stage for projects that have already passed through multiple formal and informal vetting processes. This approach allows PGE to focus its resources efficiently on the most viable projects. Therefore, one would expect a high percentage of success at this stage.

Regarding the second point, PGE's Business Resource Group (BSG) and CRG frequently

[62] CUB/400, Jenks/40.
[63] CUB/400, Jenks/41 at 2.

deferred project spend throughout the year due to resource constraints, delays in permitting and material availability, and impacts due to storms. PGE also cancelled approximately $2.5 million of projects in 2023 that where expensed and costs borne by shareholders.

Furthermore, PGE's rate review for this case relates primarily to assets that came into service in 2024, while PGE's 2024 rate review (UE 416) addressed assets coming into service in 2023. That review is complete, and all prudent assets are now included in customer prices. If CUB had concerns regarding the projects approved and in-service during 2023, these issues should have been raised in UE 416.

Q. CUB reiterates their statements that the role of PGE's capital review group is to facilitate capital spending and not to control costs.[64] What evidence does PGE provide to show that CUB's statements are untrue?

A. CUB's position appears to overlook key aspects of the information provided by PGE in both opening and reply testimony. To further clarify and emphasize the role of PGE's capital review process, we would like to highlight the following:

PGE's capital investment targets are determined through a comprehensive planning process that aligns with its strategic goals, regulatory requirements, customer needs, and operation needs. Contrary to CUB's position, while investor sentiment is important to ensure reasonable access to capital, PGE's investment targets are not decided based on earnings growth or investor sentiment. Earnings growth projections are an output of the capital plan and targets, not an input.

Upon approval of PGE's targets and budget by management and the Board of Directors, oversight responsibility is delegated to PGE's CRG and BSGs. These entities are tasked with

[64] CUB/400, Jenks/39 at 13-14.

providing governance of the project portfolio and ensuring that spending remains within approved budgets.

PGE has implemented several controls within its current capital governance process to manage project expenditures effectively. We believe it would be beneficial to revisit these controls, which are outlined as follows:

- **Project Evaluation and Prioritization** - The BSG and CRG evaluates and prioritizes capital projects based on their strategic importance, customer value, and alignment with PGE's long-term goals. This ensures that resources are allocated to the most critical projects.
- **Project Gating** – Projects complete a rigorous gating process before the BSG and CRG allocate funding. Controlling funding allocations during Ideation, Planning and Execution gates allows the BSG and CRG to control cost and risk through each stage of the capital project lifecycle.
- **Cost-Benefit-Analysis** – As part of the gating process, PGE conducts cost-benefit-analysis on projects with material investment commitments to ensure they deliver benefits to customers. Through previous data requests, PGE has provided examples of these analyses.
- **Vendor and Contract Management** – Through the gating process, PGE ensures its Supply Chain organization is negotiating favorable contracts with suppliers and contractors. This group controls the costs of equipment, materials, and labor. Contract terms often include provisions for cost control, such as fixed-price agreements or cost caps.

- **Monthly Monitoring and Reporting** – The BSGs and CRG meet monthly to review the health of the capital project portfolio relative to its approved budget and address any variances to project spend, schedule, and scope. On a quarterly basis, PGE also reports to the BOD regarding the status of its capital portfolio.

Q. CUB says that PGE does little to address affordability. Does PGE have any examples of projects that have not moved forward because of customer affordability concerns?

A. Yes. PGE recently filed its final shortlist of recommended projects submitted in response to its 2023 All-Source Request for Proposal (RFP). This RFP, a competitive bidding process to obtain the least-cost, least-risk clean energy projects, was the company's largest open application process to date. The selections demonstrate a commitment to serving our customers reliable, clean power while working to keep customer prices as low as possible. PGE declined to proceed with 1000 MW of resources due to the affordability concern for our customers. PGE will look at future procurement opportunities to address the remaining need for renewable energy projects, but we will continue to do so with customer affordability in mind.

Q. Is CUB's general assessment of PGE's capital planning process complete, accurate, and fair? If not, what does PGE believe is most important to address?

A. CUB's assessment draws broad conclusions about the overall efficacy of PGE's capital planning process based on a limited review of PGE information. CUB's conclusions rest on:

1. Year-to-year capital spending changes without exploring or understanding the underlying reasons and projects causing these changes.
2. An inference that PGE approves nearly all capital projects, based on the absence of a comprehensive list of rejected or unfunded proposals.

3. A presumption that reallocating resources to other essential projects within the annual capital plan when one project is delayed is an improper practice, despite the extensive backlog of projects that are critical to complete.

CUB's generalizations are not based on a review of the prudence of PGE's actual projects or PGE's actual capital planning practices. Therefore, we contend that for CUB's assertions to be found accurate, there should be evidence provided of PGE's failures within the projects PGE is requesting to recover, yet no support of this nature has been identified by CUB.

As supported by the evidence in this case across multiple testimonies, PGE engages in prudent business practices consistent with industry standards for its capital planning program.

Q. What does PGE request of the Commission?

A. We request the Commission reject CUB's proposal to reduce PGE's employee incentive compensation by $10.8 million due to the unrelated and unsupported assertion that PGE's *future* capital planning process is flawed.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 435

Affordability Programs

PORTLAND GENERAL ELECTRIC COMPANY

Surrebuttal Testimony of

Kristen Sheeran
Jenn Latu
Sam Newman

October 1, 2024

Table of Contents

I. Introduction and Summary

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

A. My name is Kristen Sheeran. I am the Senior Director of Policy Planning and Sustainability at PGE. My qualifications appear at the end of PGE Exhibit 1200.

My name is Jenn Latu. I am the Manager of Community Outreach at PGE.

My name is Sam Newman. I am a Senior Principal Strategy Integrator in PGE's regulatory strategy group.

We are adopting the direct testimony of Kristen Sheeran and Jake Wise previously filed in this proceeding as PGE Exhibit 1200. Our qualifications appear at the end of this exhibit.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to respond to arguments made by the Staff (Staff) of the Oregon Public Utility Commission (OPUC or Commission), the Oregon Citizens' Utility Board (CUB), Verde, and the Alliance of Western Energy Consumers (AWEC) concerning energy burden trends of PGE customers, actions PGE can take to provide additional support to energy burdened customers, and the cost allocation of those actions.

Q. What is being proposed by parties?

A. Staff, CUB, and Verde (the Coalition) reiterate calls for a range of new customer protections and programmatic actions as of the rate effective date of this rate case. AWEC continues to make a case for changes to the cost recovery methods of PGE's existing Income-Qualified Bill Discount (IQBD) program, which are opposed by the Coalition.

Q. Please summarize PGE's response to these proposals.

A. PGE's recently completed Energy Burden Assessment (EBA) provides a data-informed baseline from which to assess and prioritize the various recommendations to further enhance

PGE's IQBD program. Informed by the EBA, PGE has proposed changes to the IQBD[1] and is taking immediate steps to make customer outreach on the IQBD and other programs more effective, which will be described in an upcoming informational filing. Additionally, proposals that would impact all utilities are best considered through the OPUC's expanding differential energy burden investigation in Docket UM 2211. Given these more appropriate venues and the fact that arrearage and disconnection levels are within historical ranges, PGE does not propose incremental changes to its low-income offerings in this proceeding.

[1] ADV 1645 (PGE Adv. No. 24-19) updating PGE Schedule 18, filed September 27, 2024.

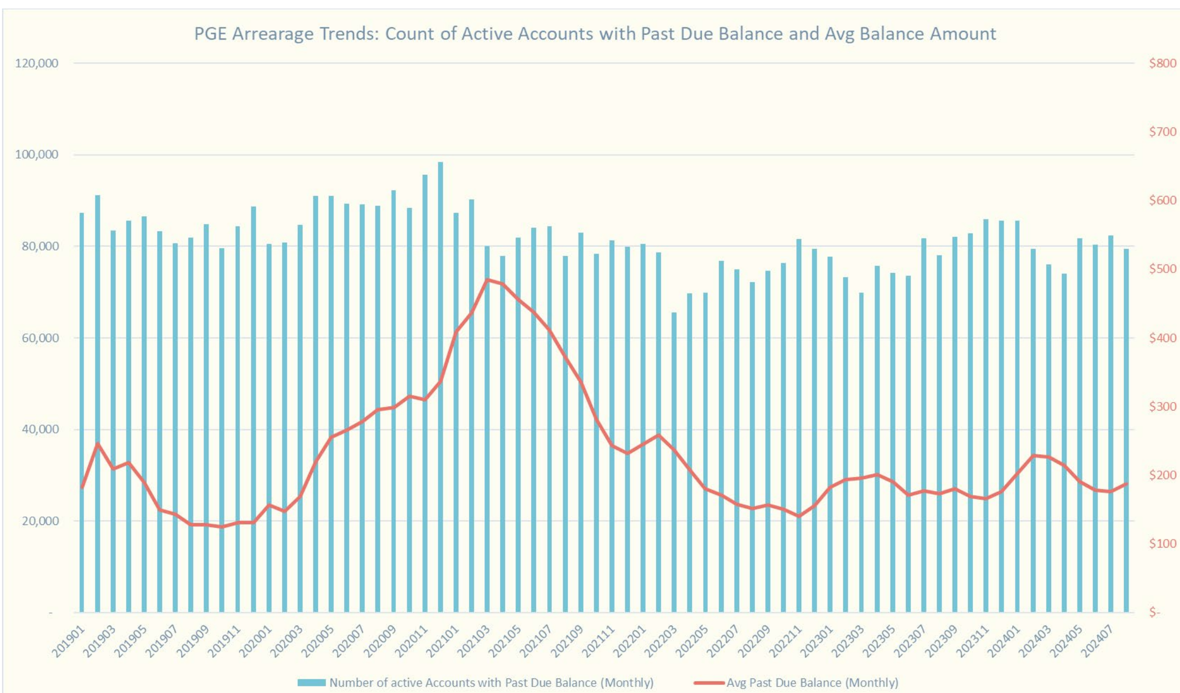
II. Energy Burden, Customer Arrearages and Disconnection Trends

Q. Please describe PGE's customer arrearages balances trend.

A. PGE residential customer past due (or arrearage) balances and disconnections are consistent with historical trends pre-COVID-19. Figure 1 shows arrearage customer counts and average balances, from 2019 through August 2024, which can display some seasonal variation. The figure shows that the average past due balance (red line) began growing during 2020 before peaking in 2021 coinciding with the COVID-19 pandemic and the COVID-19 disconnection moratorium. Since that peak, balances in arrears have declined to a level consistent with the historic range.

Figure 1

Arrearage Historical Trends

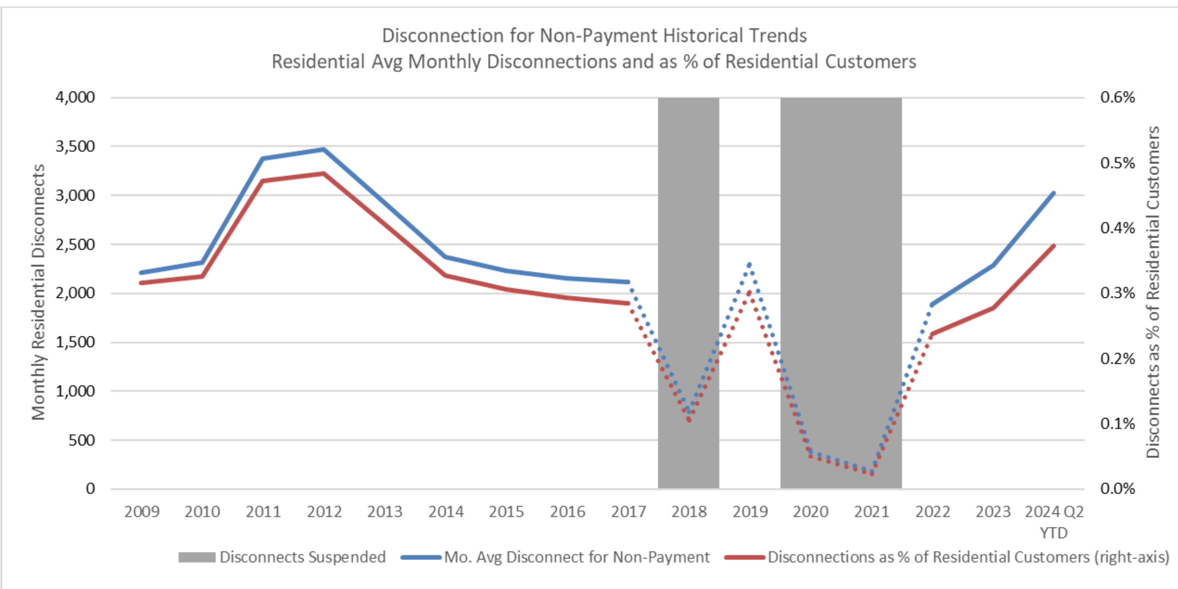


Q. Please describe trends in PGE's non-payment disconnection rates for residential customers.

A. As shared previously in PGE's reply testimony, Figure 2 shows the number of residential disconnections and disconnection rate from 2009 through 2024. Disconnections for non-payment trends were significantly disrupted by the COVID-19 disconnection moratorium and have since gradually increased to within their historical rate.

Figure 2

Disconnection Historical Trends



Q. If arrears balances and disconnections are similar to historical levels, how does the Coalition support their statements that there is a current arrearages and disconnections crisis?[2]

A. The Coalition is focusing on near-term trends and specific data points, not the trends over a longer historical period. They are also inconsistently differentiating between arrearage levels,

[2] E.g. Staff/2300, Dlouhy – Scala/5: "record disconnections for nonpayment," "arrears that remain higher than pre-pandemic levels." CUB/600, Wochele – Jenks/15: "unprecedented increase in disconnections"; Verde/200, Segovia Rodriguez/15: "crisis mitigation," "record disconnections."

which have remained mostly stable, and disconnection levels. Significant month-to-month variation, seasonal trends, and residual impacts of past disconnection moratoriums are all factors which influence higher recent growth rates since the end of the 2020-2021 moratorium. In describing 2024 disconnection levels as the highest recorded, the Coalition is comparing 2024's rate to the pre-pandemic levels in 2019, the only pre-pandemic year with data reported through Docket RO 12 (RO 12) quarterly reports.[3] While the 2024 rate is slightly higher – 14% - than the 2019 rate over the same months, the longer historical trend provides important perspective that current levels are far from unprecedented.

Q. What does the Coalition propose in response to this purported arrearages and disconnections crisis?

A. The Coalition proposes actions such as increased bill discounts, changes to disconnection processes and applicability, and arrearage forgiveness to address the perceived crisis in arrears and disconnections.

Q. Would these proposals mitigate arrearage levels and disconnections?

A. While we don't dispute the importance of finding sustainable ways to reduce customers' energy burdens and non-payment disconnections, the data does not substantiate statements that urgent, unprecedented, and procedurally expedited actions must be pursued through this rate case. Further, we believe that programs designed to address arrearages and disconnections must be carefully calibrated to maximize customer benefits and avoid the poor outcomes we mention above. In our view, the Coalition's proposals do not meet these criteria.

[3] CUB/400, Jenks/43.

III. Proposals Related to Energy Burden and Affordability

Q. Please summarize the Coalition's recommended actions to address affordability for energy burdened customers specifically.

A. The Coalition continues to advocate a number of actions, which include but are not limited to adjustments to IQBD discount levels and program details, development of new outreach approaches, additional data and reporting metrics, actions to increase procedural equity in future proceedings, actions to mitigate arrearage balances of energy burdened customers, and pauses on disconnections.

Q. Did Staff agree with PGE's statements in reply testimony that the most appropriate venue for these recommendations is in either PGE's response to EBA recommendations or in the OPUC differential energy burden investigation in Docket No. UM 2211?

A. Staff appears to largely agree. For example, addressing Verde's proposal to increase IQBD discount tiers, Staff argued for a data-driven approach aligned with the EBA, and expressed a preference to pursue such a change in UM 2211 rather than this rate case.[4] Staff also clarified that several of its recommendations could appropriately be pursued in PGE's EBA follow-up filing.[5] Related to the development of an arrearage management program, Staff clarified that they only sought measures in this proceeding that could mitigate potential impacts of the UE 435 rate increase, while viewing UM 2211 as the preferred process to address affordability issues more comprehensively.[6]

[4] Staff/2500, Ayres/6.
[5] Staff/2500, Ayres/12-13.
[6] Staff/2500, Ayres/24.

Q. Do the other Coalition members agree?

A. While noting that inclusion in UM 2211 is "procedurally an option," CUB maintains its recommendation to address affordability concerns as of the rate effective date in this docket via action in this rate case.[7] Verde also objected to PGE's position that affordability recommendations are best addressed in the EBA follow-up and UM 2211 investigation.[8]

Q. Did the Coalition re-raise recommendations in rebuttal testimony that PGE did not previously respond to individually?

A. Yes, in particular, CUB identifies several requests that were not specifically addressed: adjustment of rate effective date out of the winter, extension of the bill due date from twenty to thirty days, elimination of late fees for all residential customers, and urgent action to address energy burden prior to the rate effective date.[9] Verde similarly identifies two topics that it argues PGE failed to address: the proposal for a percentage of income payment plan (PIPP) and the proposal to apply an Oregon Self-Sufficiency Standard as the maximum income for IQBD Tier E.[10]

Q. How does PGE respond?

A. Considering the number of discrete recommendations to update programs and business practices related to bill discounts, disconnections, customer service, and other areas related to affordability, PGE prioritized responses in PGE Exhibit 1200 to the largest proposals and common themes raised by the Coalition rather than addressing every point individually. The purpose of the EBA was to inform a comprehensive approach to affordability and IQBD design, which PGE is pursuing as described in the upcoming EBA follow-up.

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[7] CUB/400, Jenks/27; CUB/600, Wochele – Jenks/15-16.
[8] Verde/200, Segovia Rodriguez/1.
[9] CUB/600, Wochele – Jenks/25.
[10] Verde/200, Segovia Rodriguez/2-3.

Q. Is CUB's proposal to eliminate winter rate increases by procedural means necessary to protect customers from high bills?

A. No. Customers who struggle with high seasonal bills already can enroll in PGE's Equal Pay customer billing arrangement to spread billed amounts evenly throughout the year. A customer enrolled in Equal Pay would not be at risk of a uniquely high mid-winter bill. Information on Equal Pay is available on PGE's 'Billing & Payment Options' webpage, shared with regular customer bills, and shared by Customer Service Advisors to customers. Currently, 51,000 residential customers participate in some form of equal pay arrangement. Additional offerings such as customer demand response programs also can offer customers bill credit during high bill months for managing their peak time usage.

Q. How does PGE respond to CUB's recommendation regarding an extension of the bill due date?

A. PGE recalls that this proposal was put forward in comments by Joint Advocates in Docket No. AR 653 in August 2022. These comments were raised as part of the process that ultimately led to adoption of an increase in the disconnection notification period to twenty days.[11] PGE prioritizes continuity in its customer processes and does not believe that an extension of the bill due date is an efficient way to reduce arrearage or disconnection levels. To the extent parties want to revisit these topics, PGE believes a process that involves all utilities and interested stakeholders via a Commission-led process is most appropriate.

[11] *In the Matter of Revisions to Division 21 Rules to Strengthen Customer Protections Concerning Disconnections. Opened at the December 16, 2021 Special Public Meeting*, Docket AR 653, AHD Report for Sep 20, 2022 OPUC Public Meeting at 13 (Sept 19, 2022).

Q. How does PGE respond to CUB's request to eliminate late fees for all customers?

A. Late fees and late fee procedures were considered in 2022 in Docket No. AR 653. As an outcome of those discussions, late fees were eliminated for all low-income customers.[12] Like the rest of the customer billing function, late fees are part of the overall framework to encourage customers to make timely payment of amounts owed. PGE's late fees are consistent with Commission rules establishing applicable past due amounts and durations.[13] As with consideration of bill due dates, to the extent CUB views this measure as a high priority, a Commission-led process is most appropriate.

Q. How does PGE respond to arguments for other immediate actions to address energy burden as of the rate effective date?

A. Coalition members offer various proposals to provide increased support to energy burdened customers as of the rate effective date of this rate case with CUB reiterating proposals for an arrearage management and forgiveness program, increases to bill discount tiers, and assistance for customers in the 61-100% SMI range.[14] PGE will be filing a thorough update on its assessment of the EBA recommendations as a follow up to its IQBD tariff update. In short, PGE's key focus is in improving awareness of IQBD to increase the reach of the existing program, which we believe will be more impactful than efforts to scope and implement new emergency assistance programs. This focus is grounded in the EBA, which reports that bill discount and bill assistance funding covered 51% of low-income assistance needs in 2024 versus best practice at program maturity of sixty to seventy percent. This represents a major milestone achieved in the two years since PGE designed and launched IQBD in 2022. Growth

[12] OAR 860-021-0126(3).
[13] OAR 860-021-0126.
[14] CUB/600, Wochele – Jenks/6.

toward maturity of IQBD offers a readily available way to increase support provided to customers. PGE is open to consideration of additional programs including support for energy-burdened customers with persistent arrearages but believes further understanding of needs and potential approaches is appropriate before launching new programs.

Q. How does PGE respond to Verde's arguments for a PIPP?

A. A PIPP design represents a fundamentally different program structure from bill discount programs now offered by all Oregon investor-owned utilities, and one that would be complex to implement. From the onset of the IQBD program, PGE has prioritized a simple design that has a low barrier for enrollment to ensure it has maximum reach to those who need it most and this remains our priority. At this point, PGE is committed to the success of its current IQBD design which is not yet at full enrollment.

Q. How does PGE respond to Verde's arguments for incorporation of a self-sufficiency standard?

A. Use of an Oregon self-sufficiency standard as an alternative eligibility threshold of IQBD Tier E is directionally aligned with the EBA's recommendation to consider additional support that could be offered to customers in the 61-100% SMI range who are not currently eligible for IQBD. However, as Verde states, 215 out of 360 hypothetical three-member family permutations would exceed the 60% SMI threshold, indicating that this change would represent a change to the size and cost of the program and add additional administrative complexity to confirm eligibility and update participant information over time in a program in which eligibility could potentially be location and age-dependent.[15] PGE is open to further exploration of the details and potential costs of this concept through future stakeholder

[15] Verde/104, Segovia Rodriguez/22.

discussions of strategies to support energy burdened customers outside of current IQBD eligibility.

Q. How does PGE respond to any of the other previously offered recommendations?

A. PGE does not reiterate its position on all recommendations. PGE sees potential that many of the suggestions not addressed via our EBA update filing to be taken up more fully in UM 2211. We look forward to further consideration of these topics in those venues.

Q. What is the status of the previously mentioned EBA update filing?

A. On September 27, 2024, PGE filed an update to IQBD offered through Schedule 18.[16] PGE intends to follow up with additional information in an EBA update filing in Docket UM 2211, putting forth specific proposals and progress updates on all EBA recommendations, as well as certain recommendations raised in this proceeding which align with EBA recommendations.

Q. Do these EBA update filings present meaningful action PGE is taking to improve outcomes for energy burdened customers?

A. Yes. In its tariff filing, PGE seeks Commission approval of specific IQBD changes that will establish a new discount program for master-metered multifamily housing, partially in response to Staff's recommendations in this proceeding. In addition, the tariff changes will allow PGE to implement a targeted post-enrollment verification approach. PGE is also already working expeditiously to execute on plans regarding improvements to program updates, outreach and implementation informed by its EBA.

[16] *PGE Advice No. 24-19, Schedule 18, Income Qualified Bill Discount*, Docket ADV 1645 (Sep. 27, 2024).

Q. Have there been material developments since PGE's reply comments in the Commission's investigation of energy burden issues in Docket UM 2211?

A. Yes. On September 16, 2024, Staff published an Arrearages and Disconnections Assessment which informed a Staff-led workshop held on September 17, 2024.[17] These developments have established Docket UM 2211 as the appropriate venue to consider actions to address disconnection and arrearage-related matters. On September 20, 2024, Staff circulated a proposal for an Energy Burden Metrics Report to the Docket UM 2211 service list, which informed a second Staff-led workshop held on September 24, 2024. Additionally, changes to IQBD and other programs remain in scope via the programs and rates workstreams and are the subject of an upcoming third Staff-led workshop on October 10, 2024.

Q. Per Staff's request, does PGE commit to substantively engage on proposals to enhance customer protections in the upcoming winter heating season in Docket UM 2211?[18]

A. Yes, PGE commits to substantively engage in efforts to scope and develop such proposals.

Q. Does the Coalition introduce any new recommendations in rebuttal testimony?

A. Yes. In addition to reiterations of, and adjustments to, previous recommendations discussed above, the Coalition presented the following new recommendations:

- CUB requested PGE consider extending time payment arrangements (TPA) from twelve to twenty-four months.[19]

[17] *In the Matter of Public Utility Commission of Oregon, Implementation of House Bill 2475*, Docket UM 2211, Staff Arrearages and Disconnections Assessment (Sep 16, 2024).
[18] Staff/2500, Ayres/24.
[19] CUB/600, Wochele – Jenks/26.

- CUB requested PGE make changes to standardized data reporting in Docket RE 195, including providing updates on IQBD re-enrollment and post-enrollment verification and arrearage data for all customers.[20]
- CUB recommended modifications to PGE's approach to engage PGE's Community Benefits and Impacts Advisory Group (CBIAG) to promote procedural equity, including implementation of neutral, third-party technical support, walkthroughs of technical data, and accessible data visualizations.[21]
- Staff, CUB, and Verde provided related recommendations emphasizing expectations for stakeholder venues that allow feedback to inform and influence PGE proposals on energy justice and affordability issues. Staff emphasized shared learning and co-design as goals for such spaces.[22]

Q. How does PGE respond to these new recommendations?

A. PGE responds as follows:

- PGE's TPA approach follows OPUC Rules.[23] The suggestion to extend TPAs to twenty-four months for all customers was considered in 2022 in Docket AR 653. An extension to twenty-four-month TPA standard was proposed by Joint Advocates, and the Joint Utilities explained that defaulting to a twenty-four-month TPA will not be a benefit to customers.[24] Based on Staff analysis, the Commission did not extend TPAs and PGE believes the same arguments are applicable today.

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[20] *Id*. 13.
[21] CUB/600, Wochele – Jenks/23-24.
[22] Staff/2500, Ayres/14; CUB/600, Wochele – Jenks/26.
[23] OAR 860-021-0415
[24] *In the Matter of Revisions to Division 21 Rules to Strengthen Customer Protections Concerning Disconnections*, Docket AR 653, Order No. 22-214, Appendix A at 34-35 (Jun. 10, 2022).

- CUB's proposed changes to Docket RE 195 reporting should be considered within Docket UM 2211's data workstream. In that docket, Staff has proposed consolidating RE 195 reporting into RO 12 with a goal of streamlining and standardizing reporting across all utilities.[25] Staff's Energy Burden Metrics Report proposal, circulated to the UM 2211 service list on September 20, 2024, includes elements of CUB's recommendation, including new monthly data points on total residential arrearages and bill discount program un-enrollments. PGE will be filing comments on Staff's proposal on October 8, 2024.
- PGE continues to iterate its practices to engage the CBIAG and appreciates CUB's suggestions on approaches to consider that may make the process more effective. The CBIAG is comprised of members who are largely new to the energy industry, and PGE actively engages and ensures it consults the CBIAG across seven broad and complex topic areas.[26] PGE has engaged Espousal Strategies as a third-party expert to facilitate CBIAG meetings. Espousal Strategies has extensive experience in meeting process design with equity-focused community advisory groups. PGE meets with Espousal Strategies weekly to collaborate on development of materials for CBIAG meetings, including the accessibility and framing of technical topics. PGE's strategy for engaging our CBIAG includes exploring topics that are scoped in HB 2021 in a way that is relevant and relatable to members. Our goal is to bring forth information with the intent of increasing awareness and developing understanding amongst our members. We will continue to engage the group on energy burden and

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[25] UM 2211, Staff Data Landscape Analysis (June 7, 2024).
[26] ORS 469A.425(2)

disconnection topics as they appropriately align to other topics that have been presented and discussed or that we have committed to doing so.

- Regarding engagement beyond the CBIAG, such as with the recently discontinued IQBD Stakeholder Group, PGE's approach is a work in process which seeks to provide opportunities for direct and candid feedback as well as open venues on topics that matter to communities and stakeholders. In particular, we have recognized that community action partner agencies and community-based organizations have specific needs and interests in administrative elements of programs and needs to support clients who are PGE customers. As part of this process, PGE is developing an updated approach to convening and updating interested stakeholders across relevant policy-related topic areas. PGE commits to make best efforts to provide interested stakeholders accessible opportunities to engage and provide input on topics of interest in advance of PGE filings and formal regulatory processes, including on issues related to EBA and IQBD.

Q. Please summarize any updates to AWEC's position on cost recovery and other issues for IQBD.

A. In opening testimony, AWEC argued that IQBD cost recovery (Sch 118) be capped at twenty million kWh per-customer, and that recovery of IQBD costs be based on revenue rather than kWh usage. In rebuttal testimony, AWEC clarified that their per-customer cap recommendation would only apply to Schedule 90 and that a revenue-based allocation could leverage treatment of Direct Access customers as though they were Cost-of-Service customers to mitigate disproportionate contributions from Direct Access customers. AWEC also offers a new, alternative cost recovery approach that treats IQBD recovery similar to uncollectible cost recovery and assigns attribution based on cost causation, via the "consumer function." [27] Finally, AWEC expresses openness to considering verification changes through a separate process outside of this rate case.[28]

Q. What position does the Coalition take regarding AWEC's proposals?

A. The Coalition is not supportive of AWEC's opening proposals and highlights the consequential rate pressure on Residential Customers. Staff echoes PGE's warning that a strict revenue-based allocation, as opposed to usage-based, contrasts the non-bypassability component of ORS 757.695(2)[29] due to the reduced revenues from Direct Access customers who do not purchase energy from PGE. Staff recommends keeping the current structure of Schedule 118 in this proceeding and continuing to evaluate IQBD cost recovery rate design in Docket UM 2211.

CUB specifically takes issue with AWEC's proposed changes to Schedule 118, drawing a parallel between cost recovery for the Public Purpose Charge (PPC, Schedule 108) and for IQBD as motivation for changing the structure of Schedule 118, noting the unique intent of IQBD to shift costs away from residential customers.

Q. How do you respond to AWEC's argument that it would not be administratively burdensome for PGE to implement a per-customer cap that "will only affect a handful of customers"?[30]

A. PGE disagrees with AWEC's premise that PGE's Key Customer Managers (termed "dedicated billing managers" in AWEC's testimony[31]) implement billing calculations for

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[27] AWEC/400, Kaufman/20.
[28] AWEC/400, Kaufman/21.
[29] ORS 757.695(2) requires that "consumers that purchase from electricity service suppliers pay the same amount to address the mitigation of energy."
[30] AWEC/400, Kaufman/17.
[31] AWEC/400, Kaufman/17.

large customers. Billing calculations are handled within PGE's customer billing system. To implement a new calculation for Schedule 90 service agreements would require system configuration and maintenance. In discovery, PGE responded that ongoing maintenance would likely be less if this unique per-customer cap structure were applied only to the relatively few service agreements on Schedule 90; however, if applied to all service agreements that shared a customer unit with Schedule 90 service agreements, ongoing maintenance of such a mapping would be more extensive.[32]

Q. How does PGE respond to AWEC's argument that since IQBD may reduce residential arrearages that would otherwise be written off, OPUC should adopt a cost allocation approach in which large customers pay proportionally less of the costs relative to small commercial and residential customers, similar to the cost allocation of uncollectible expense?[33]

A. PGE does not concur that traditional cost causation principles apply to cost recovery for policy instruments like IQBD. House Bill 2475 (HB 2475), the foundation of IQBD, expressly moves the Commission away from a strict economic regulator role and requires broader consideration of affordability when designing rates, which presumably applies to the structural design of cost recovery for IQBD itself. If cost causation were more prominently featured in IQBD cost recovery design, a higher share of program costs could be allocated to residential customers. This would reduce benefits to IQBD participants and impact energy burdened customers whose incomes-are above the IQBD eligibility threshold.

[32] AWEC/205, Kaufman/20.
[33] AWEC/400, Kaufman/20.

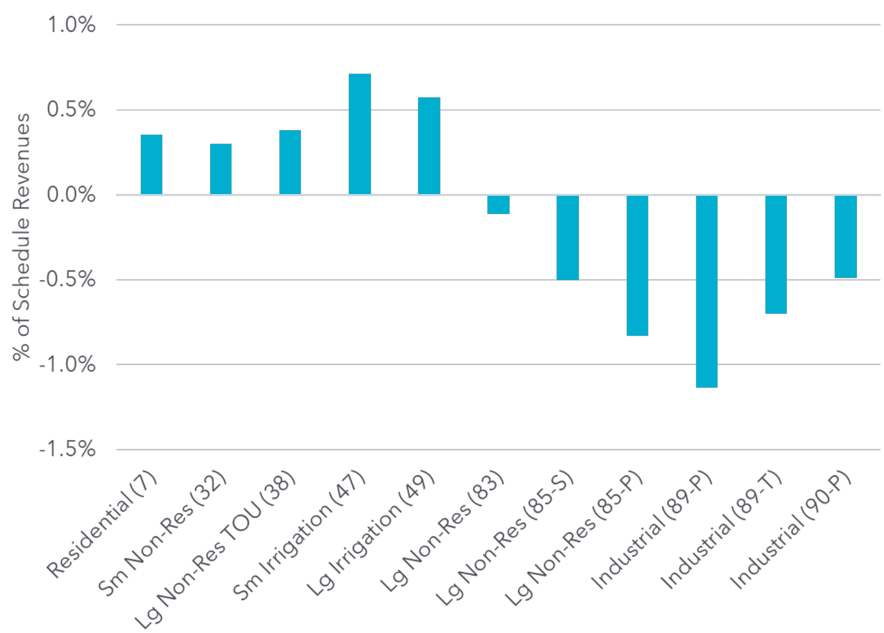
Q. Can PGE provide additional context on its conclusion that a revenue-based IQBD cost allocation would result in significant cost shifting away from large customers relative to the current energy-based allocation?

A. PGE can agree with AWEC that the entire premise of IQBD is a cost shift, which shifts responsibility for costs of the system away from low-income customers; this cost shift is expressly directed in HB 2475. PGE also recognizes that the impacts of alterative cost recovery frameworks are relative to the current structure, which mirrors the collection schedule for low-income energy assistance (Schedule 115) because of the shared goal of funding bill affordability. In reply testimony, PGE concluded that a revenue-based cost allocation would shift program costs that are currently recovered from larger customers to residential and small non-residential customers, and cautioned the decreased contributions from Direct Access customers would run counter to non-bypassability language in HB 2475 and ORS 757.695(2).

AWEC's revised proposal is for a revenue-based allocation that uses calculated revenues that charge Direct Access customers the same as their Cost-of-Service counterparts. This methodology is used in collections for Community Solar, Transportation Electrification and PGE's Community Benefits and Income Advisory Group, all of which advance explicit policy objectives and hence have similarities to IQBD. AWEC's proposal also contains the continued application of a cap on load that would be subject to the Schedule 118 charge. Taken together, AWEC's proposed adjustments level the proportionate contributions of all schedules except for Schedule 90 by shifting contributions from large commercial schedules to residential and small commercial schedules.

PGE does not take a position on AWEC's revised revenue-based allocation methodology. PGE does provide Figure 3, which displays the change in the overall rate schedule impacts under AWEC's proposal, with capped usage, relative to the current cost recovery structure. Positive values indicate an increase in contributions, as a percent of schedule-level revenues; negative values indicate a decrease. Figure 3 supports PGE's statement in PGE Exhibit 1300 indicating AWEC's proposal would shift IQBD cost recovery from large industrial rate schedules to residential and smaller commercial rate schedules.

Figure 3
Impact to Current Schedule 118 Contributions: AWEC Proposal vs. Status Quo



IV. Qualifications

Q. Jenn Latu, please state your educational background and experience.

A. I have a Bachelor of Business Administration from Warner Pacific University and a Master of Arts in Industrial and Organizational Psychology from Touro University Worldwide. I joined PGE in 2012 as a frontline employee in Customer Operations and went on to support that department through a series of projects as a Change Management professional. In 2018, my career at PGE shifted into focusing on underserved communities within our service area. Since then, I have maintained a portfolio of equitable outreach and engagement with environmental justice and underserved communities. This includes the standing up and ongoing management of PGE's CBIAG and the outreach associated with PGE's IQBD program.

Q. Sam Newman, please state your educational background and experience.

A. I received a Bachelor of Science and a Master of Science in Civil Engineering from Stanford University. I joined PGE's regulatory strategy team in 2021. My responsibilities have focused on development and advancement of new business and regulatory approaches driven by the changing electric industry landscape, especially in response to HB 2021. I have led development of PGE's approaches on topics including the Clean Energy Plan, the CBIAG, distribution system planning, customer energy burden issues, and other areas. Prior to joining PGE, I held roles at Rocky Mountain Institute as a consultant on industrial and electric sector initiatives, and at Pacific Gas & Electric Company in energy efficiency program management, business strategy for grid innovation, and structured transactions.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 435

Revenue Requirement

PORTLAND GENERAL ELECTRIC COMPANY

Surrebuttal Testimony of

Greg Batzler
Stephanie Meeks

October 1, 2024

Table of Contents

I. Introduction

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

A. My name is Greg Batzler. My position is Senior Regulatory Consultant, Regulatory Affairs. My qualifications appear in PGE Exhibit 200.

My name is Stephanie Meeks. I adopt the direct testimony of Jaki Ferchland filed in this proceeding in PGE Exhibit 200. My position is Regulatory Consultant, Regulatory Affairs. My qualifications appear in PGE Exhibit 1300.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to respond to the rebuttal testimony put forward by the Staff of the Public Utility Commission of Oregon (Staff), the Oregon Citizens' Utility Board (CUB), and the Alliance of Western Energy Consumers (AWEC) (collectively, Parties) with respect to PGE's 2025 Test Year revenue requirement.

Q. Have you updated PGE's revenue requirement since filing your reply testimony?

A. Yes. In addition to the $18.0 million reduction, we incorporated as part of our reply testimony,[1] PGE has incorporated additional adjustments to its January 1 base business request in this case in response to Parties rebuttal testimony. These adjustments reduce PGE's base business request by an additional $3.0 million. When added to the $18.0 million of reductions PGE included in reply testimony, incorporating updated load forecast and updated base revenues for 2024,[2] PGE's revised base business request, inclusive of the Constable

[1] PGE Exhibit 1301. PGE made a slight correction to the calculation of Constable deferred ITC benefit, which resulted in an increase of approximately $0.2 million.

[2] PGE notes that 2024 base revenues have been updated to remove Clearwater, as a decision in UE 427 is not expected until early 2025.

Battery Energy Storage System (BESS), results in a $257.8 million, or 8.6% increase for base business as of January 1, 2025.[3]

Q. How is the remainder of your testimony organized?

A. After this introduction, we have 10 sections:

- Section II – Overview and Summary
- Section III – Rate Base Mismatch Calculation
- Section IV – Investment Tax Credits (ITC)
- Section V – Anderson ITC
- Section VI – Accumulated Deferred Income Taxes (ADIT)
- Section VII – Cash Working Capital
- Section VIII – Operating Materials and Fuel Stock
- Section IX - Other Revenue – Joint Pole and Steam Revenue
- Section X – PGE Grants
- Section XI – Capital Attestations

[3] The 8.6% increase is relative to the total price change for 2025.

II. Overview and Summary

Q. Have Parties modified any of their opening testimony adjustments in response to PGE Exhibit 1300?

A. Yes. In addition to accepting the adjustments PGE included within Exhibit 1300, parties have modified their opening testimony adjustments as follows:

- AWEC has withdrawn the entirety of their proposed cost of removal adjustment.
- AWEC has accepted PGE's proposal for the Oregon Commercial Activities Tax, removing the remainder of their adjustment for this expense.
- Staff has modified their PGE Grants adjustment from a reduction of $700,000 to a reduction of $600,000, removing their proposed adjustment of $100,000, associated with the four federal grants PGE has received thus far.

Q. Are there any proposals made from Parties in their opening testimony that PGE did not respond to in reply testimony that you would like to respond to here?

A. Yes. Staff proposed that PGE amortize the Clearwater deferral over a one-year period beginning on January 1, 2025.[4] Additionally, with rebuttal testimony, Staff noted that while their proposal has not changed, a Commission order in Docket UE 427 (UE 427) has been further delayed.[5]

Q. Does PGE have any issues with Staff's proposal?

A. Yes. Since Staff filed their rebuttal testimony, the timing in UE 427 has been further delayed, such that a Commission order will not be issued until the first quarter of 2025. Based on this updated information, PGE recommends filing to begin amortization of the deferral in 2025

[4] Staff/1700, Dlouhy/3.
[5] Staff/2400, Dlouhy/24.

following a Commission order in UE 427. PGE agrees with the one-year period recommended by Staff.

Q. Is PGE providing an updated revenue requirement as part of this testimony?

A. Yes. PGE Exhibit 2401 provides an updated revenue requirement, which includes the changes and recommendations discussed within PGE's reply and surrebuttal testimonies, including impacts from PGE's May 1, 2024 plant update provided earlier in this proceeding, and forecasted net variable power costs (NVPC) as of October 1, 2024 provided in Docket UE 436. Additionally, PGE has updated the load forecast for this proceeding and included supporting work papers as part of PGE Exhibit 3100. Table 1 below provides the revenue requirement impacts of the proposed adjustments included in PGE's surrebuttal testimony and shows the corresponding PGE Exhibit.

Table 1
Adjustments to Revenue Requirement (000s)

Adjustment	Testimony	Rev Req Impact
Reply Testimony Adjustments	Exhibit 1300	(17,966)*
Casualty Insurance	Exhibit 2500	(497)
Property Insurance	Exhibit 2500	(1,901)
Health and Dental	Exhibit 2500	(504)
Anderson ITCs	Exhibit 2400	(63)
Total		**(20,931)**

*Note that this amount changed from ($18,159) to ($17,966) from a correction to Constable ITC treatment

Q. What is the impact to PGE's revenue requirement in this proceeding from the above adjustments?

A. Including the adjustments in Table 1 and PGE's reply testimony adjustments summarized in PGE Exhibit 1300, PGE's base business revenue requirement request in this case, inclusive of Constable is now $257.8 million, or 8.6% of the total expected increase beginning January 1, 2025.[6]

[6] NVPC is now forecast to be 0.3% of PGE's total expected January 1, 2025 increase.

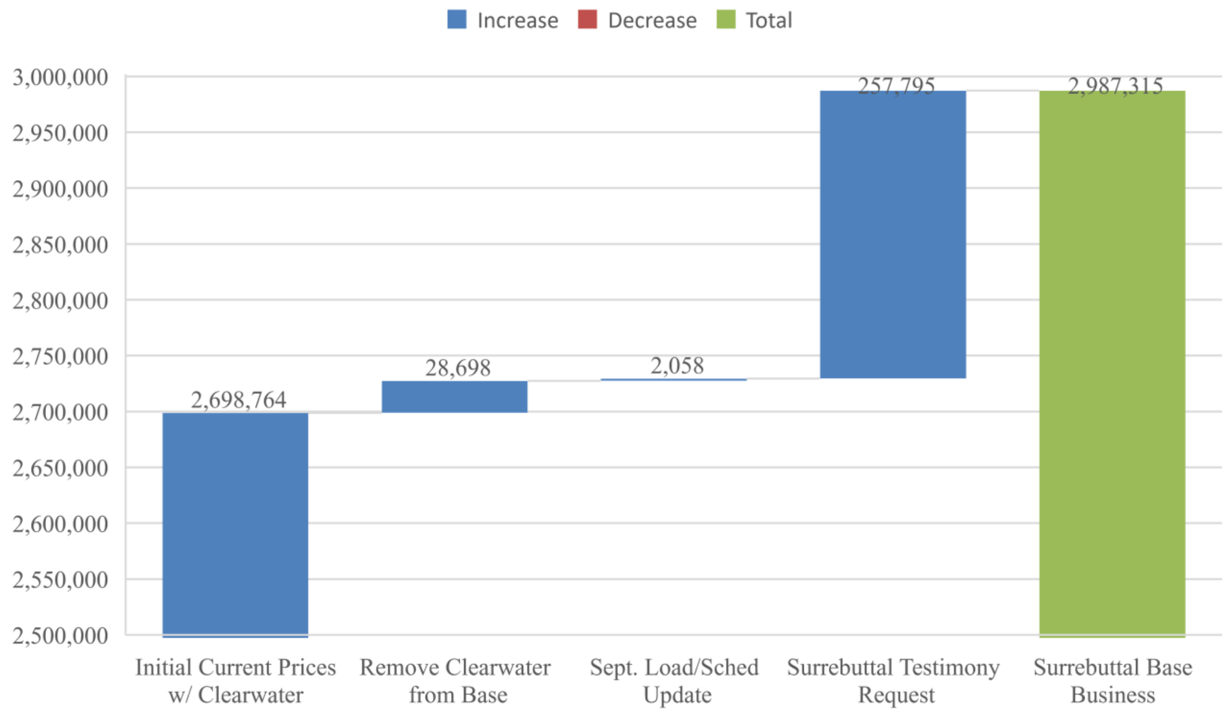
Q. Please explain the changes that have resulted in PGE's request updating from $190.5 million in reply testimony to $257.8 million here.

A. At a high level and as we illustrate below in Figure 1, this change is the result of three primary updates. First, PGE has reduced our requested 2025 base business request by an additional $3.0 million due to adjustments suggested by Parties that PGE has accepted based on more updated information. Second, PGE has updated our load forecast for 2025 and removed a supplemental schedule from current revenues. Third and most impactful to the above change, PGE has removed the impacts of Clearwater from our 2024 baseline.

When we initially filed our rate review request, it included the Clearwater project in base rates for 2024 with the assumption that a Commission order in UE 427 would be issued in 2024. As an order in UE 427 is not expected until 2025, there will be no price change in 2024 associated with the Clearwater project and thus customers will not recognize the net benefits of Clearwater within their 2024 prices. This results in a total increase of approximately $28.7 million to PGE's current prices. However, when isolating base business from NVPC, PGE's base business request increased by approximately $68 million, while the power cost increase has decreased by approximately $96 million due to Clearwater being removed from 2024 current prices.[7] While originally expected to be reflected in 2024 and thus not discussed in this proceeding previously, PGE notes that, in aggregate, Clearwater will reduce customer prices by approximately 1%.

[7] The 2024 fixed costs and NVPC benefits for Clearwater are part of PGE's Schedule 122 advice filing, which is pending a Commission decision during 2025 and as a result will not result in a customer price change for 2024.

Figure 1
Reply Testimony to Surrebuttal Impacts



III. Rate Base Mismatch Calculation

Q. Please briefly summarize how PGE calculates rate base.

A. PGE calculates rate base by identifying the total plant balance, minus depreciation, as of December 31, 2024—i.e., the balance that will be in effect for the forward test year.[8] This calculation begins with actual balances as of December 31, 2023, and then includes plant additions placed in service over 2024, as well as annualized 2024 depreciation for these new assets. This approach:

- Most accurately reflects the total plant balance that will be in service during the forward test year;
- Ensures that plant additions are offset by adequate depreciation;
- Respects ORS 757.355(1) by not including rate base additions past the rate effective date; and
- Observes the matching principle by using the same period to measure all components of net plant.

Q. Please briefly summarize other Parties' positions concerning how to calculate rate base.

A. Both Staff and AWEC continue to propose modified methods for calculating rate base. Specifically, Staff proposes to reduce PGE's December 31, 2024, rate base amount by subtracting an additional one-half years' worth of depreciation[9] during the test year, despite the fact that Staff does not propose to include corresponding rate base *additions* during the test year.[10]

[8] See PGE/1300, Batzler-Meeks/12.
[9] While Staff did not provide numerical support for their adjustment, an average of monthly average increase to accumulated depreciation will result in approximately one-half years' worth of depreciation.
[10] Staff/3000, Stevens/21.

Meanwhile, AWEC proposes to calculate rate base using a historical average-of-monthly-averages (AMA) approach for plant balances in 2024, rather than the actual total rate base forecast that will be in effect just prior to the start of the test year.[11]

PGE previously discussed the inappropriateness of both Staff's and AWEC's proposed methods in detail in Exhibit 1300, Batzler-Meeks/11-18 (Staff's approach), 18-24 (AWEC's approach). In essence, while both Staff and AWEC proposals employ a mismatch, they do so in unique ways.

Q. Has either Staff or AWEC modified their approach between opening and rebuttal testimonies?

A. No. While both Staff and AWEC filed rebuttal testimony on the calculation of rate base capital, each Party's position remains unchanged. We address both Parties' new arguments underlying these positions below.

A. Staff's Rate Base Calculation

Q. Does Staff modify any arguments to support reducing the December 31, 2024 rate base balance by 2025 depreciation?

A. Yes. Staff adds to their argument that this one-sided reduction in PGE's test year rate base is necessary on the premise that PGE's rate base is "artificially inflated" because test year depreciation is not subtracted from rate base.[12] Thus, Staff is asserting that PGE's rate base is inflated because Staff's adjustment has not been made, and that this inflation thus requires Staff's adjustment. This circular reasoning is incoherent. PGE's rate base, as measured on

[11] AWEC/300, Mullins/10.
[12] Staff/3000, Stevens/24 ("Staff is arguing that PGE's rate base is artificially inflated as customers are not credited in rate base used in the rate of return expense component for depreciation expense paid during the Test Year.").

December 31, 2024, is *not* artificially inflated because it has not been *reduced by 2025* depreciation.

Q. Why is reducing year-end 2024 rate base by 2025 depreciation amounts inappropriate?

A. During the test year, PGE both incurs depreciation expense (reductions to rate base) and experiences regulatory lag as new capital assets are included (additions to rate base). If 2025 capital additions after the rate effective date cannot be included, as Staff argues, a balanced assessment of rate base for 2025 is impracticable. The closest *balanced* approximation of rate base would be the amount in effect just prior to the test year—namely, on December 31, 2024, as PGE proposes.

Q. Does Staff address PGE's point that Staff's approach violates the matching principles?

A. Indirectly, yes. Staff notes that "the future Test Year paired with ORS 757.355 makes strict compliance with the matching principle inherently difficult."[13] Nonetheless, Staff does not attempt to correct this deficiency by removing the mismatched adjustment and using a balanced measurement of rate base. Instead, Staff contends that reducing rate base by test year depreciation would not "unduly disrupt[]" the balance between regulatory lag and depreciation because of the existence of other, unnamed "trackers" that otherwise reduce regulatory lag.

Q. Do you agree that the existence of other unspecified tracking mechanisms supports an artificial reduction to PGE's rate base?

A. No. Rather, Staff appears to be suggesting that increasing PGE's regulatory lag is appropriate because PGE seeks to mitigate high levels of regulatory lag. While Staff attempts to disclaim the suggestion that its attempt to inject additional regulatory lag "is in response to the

[13] Staff/3000, Stevens/24, at 5-7.

Company's efforts to reduce regulatory lag[,]"[14] Staff offers no other explanation for how its approach is anything other than a disruption of the balance between depreciation and regulatory lag.

Q. Does Staff recognize that its recommendation does not match PGE's actual capital investments and financial reporting?

A. Yes. Staff acknowledges that PGE's large capital investments in the test year will not be included in their calculation, which will also not align with financial reporting in actuals.[15] For financial reporting, PGE will account for actual financial results on an annualized basis for the capital investments, accumulated reserve, depreciation, expenses, and income taxes. In contrast, the calculation that Staff recommends is not consistent in reflecting an annualized period. Instead, it mixes capital investments from one period with averaging of monthly averages including accumulated reserves into a different period. Staff claims that an approach that reflects PGE's actual gross plant "would violate ORS 757.355, as capital additions placed into service after the rate effective date cannot be included in rates."[16] Staff's response seemingly ignores the fact that PGE's approach, which has been used since 2015 both matches actual capital investments *and* avoids violating ORS 757.355—while also respecting the matching principle.

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[14] Staff/3000, Stevens/25, at 5-6.
[15] *Id.* 23.
[16] *Ibid.*, at 12-14.

Q. Staff claims that its rate base calculation approach would not violate generally accepted accounting principles (GAAP) because it "is meant to only be used for ratemaking purposes."[17] How do you respond?

A. The fact that Staff's approach would be used for ratemaking purposes only is irrelevant. Rather, the fact that Staff's method would violate GAAP should be a strong indication that its approach to accounting for rate base is inappropriate and unbalanced.

Q. Staff indicates that it "does not have the resources or data to complete the analysis needed in the time allowed in this rate case to make a precise adjustment[,]" but that either PGE should calculate the adjustment for Staff, or the Commission should adopt Staff's estimated adjustment.[18] How do you respond?

A. While PGE does not agree that an adjustment based on an "estimate" is appropriate, we recognize the challenges of navigating the technical complexities of rate base calculations on constrained general rate case timelines. Crucially, modifications to PGE's rate base and depreciation expense calculations in this case would be interpreted as a drastic change for PGE's cost recovery and should not be adopted based on an admittedly incomplete analysis.

Q. Do you have any concluding thoughts on Staff's rate base calculation?

A. Yes. Staff continues to advocate for their own rate base calculation method. However, they have not adequately addressed why PGE's approach is not preferable. PGE's method offers several advantages: (1) it accurately reflects PGE's plant balance; (2) it adheres to the matching principle by aligning depreciation with rate base additions; and (3) it abides by the ORS 757.355(1) limit by not including post-rate effective date capital additions. Staff has not provided a compelling explanation for why these benefits of PGE's approach should be

[17] *Id*. 26, at 10.
[18] Staff/3000, Stevens/27.

disregarded in favor of their proposed calculation method. Rather, Staff appears to begin with the assumption that PGE's actual December 31, 2024 rate base is "artificially inflated" in order to arrive at a methodology that will reduce PGE's recovery of prudent capital investments.

B. AWEC's Rate Base Calculation

Q. Does AWEC offer any additional arguments or responses to support their 2024 AMA approach?

A. No. Rather than seeking to explain why a historical test year approach to evaluating rate base is appropriate, AWEC simply expands on its objections to PGE's rate base calculation.

Q. What is AWEC's position concerning PGE's rate base calculation?

A. AWEC argues that PGE's December 31, 2024 calculation (a) increases overall revenue requirement, and (b) is not a standard rate base valuation method. We disagree with both points.

Q. As an initial matter, is AWEC correct that PGE calculates 2024 depreciation by assuming, *for purposes of the depreciation calculation*, that these assets were placed in service on January 1, 2024?

A. Yes. PGE attempted to make clear in reply testimony that the January 1, 2024 date was used only "to calculate and provide customers a full year of accumulated depreciation benefit for new 2024 assets"—but that PGE did not otherwise generally assume a January 1, 2024 in-service date.[19] As PGE also explained, assuming that these assets entered service at the

[19] PGE/1300, Batzler-Meeks/19-20.

beginning of 2024 for purposes of the depreciation calculation actually *reduces* PGE's December 31, 2024 rate base.[20]

Q. AWEC's asserts that "PGE gets higher depreciation expense on new plant additions, without recognizing the lower depreciation expense and lower rate base valuation for the existing plant."[21] Do you agree?

A. No. AWEC appears to have confused how PGE handles depreciation for both 2024 plant additions and the existing plant balances. To be clear, PGE calculates the net plant balances as of December 31, 2024, and the corresponding depreciation expense for a full year of recovery. In using the net plant, PGE captures the lowered rate base of any existing plant balances. Further, to align the new plant additions to rate base, PGE reduces the net plant balances by adding the depreciation expense to the accumulated reserve. This calculation is to put the rate base capital balances in the revenue requirement calculation to December 31, 2024—the day prior to the effective date for rates in the proceeding.

Q. AWEC argues that PGE's rate base calculation "is not a standard rate base valuation method."[22] Do you agree?

A. No. AWEC's characterization appears premised on a misunderstanding of how PGE calculates rate base. Specifically, AWEC states that PGE measures rate base over a 12-month period, which is incomplete. Rather, PGE uses the plant balances as of December 31, 2024, which does include plant additions that would be in-service and used as of that date. This process is a standard rate-making end-of-period calculation. PGE then calculates the

[20] PGE/1300, Batzler-Meeks/21 ("This date is only a proxy used in the calculation of annualized depreciation for new plant additions. . . . which reduces the December 31, 2024 gross plant to calculate the net capital in rate base.").
[21] AWEC/300, Mullins/14, at 20-21.
[22] *Id*. at 21-22.

annualization of depreciation expense for the plant additions in 2024. This calculation provides two components: (1) annual depreciation expenses to capture a full year for the revenue requirement, and (2) the amount to add to the accumulated reserve to reduce the gross plant additions in 2024. Thus, PGE is not using "inconsistent periods" to calculate rate base and depreciation expenses, but is instead consistently looking to applying 2024 depreciation levels and plant additions to ensure the most accurate rate base and depreciation expenses applicable to the test year—namely, that in effect on December 31, 2024.

Q. Does Staff agree with the approach that AWEC provides?

A. No. Staff acknowledges that AWEC's approach "is not necessarily in line with the concept of a future Test Year[,]"[23] and is more aligned with the use of a historical test year.

Q. Does AWEC attempt to address the fact that their AMA proposal is essentially adopting a historical test year for rate base?

A. No. AWEC does not comment on the fact that its 2024 AMA approach functionally applies a historical test year, despite Oregon having standardized the use of a forward test year for decades.

[23] Staff/3000, Stevens/27, at 11-12.

IV. Investment Tax Credits (ITC)

Q. What was PGE's initial proposal in this case regarding the ITCs for the Constable and Seaside battery energy storage facilities?

A. As detailed in PGE Exhibit 500, PGE proposed to provide the sales value of the investment tax credits for Constable and Seaside over a five-year period on a declining value basis such that the value received the first year would fully offset the revenue requirement of the Seaside plant in-service.

Q. How did the parties respond?

A. None of the Parties were in support of PGE's proposal.

- Staff opposed accelerated distribution of ITC value to customers, citing concerns about future rate increases and intergenerational inequity.
- AWEC argued that PGE's proposed five-year front-loaded amortization of ITC value is unfair, as it does not reduce PGE's rate base or asset returns.
- CUB did not provide a specific response to PGE's proposal.

Both Staff and AWEC then proposed to include the ITC within the revenue requirement as an offset to rate base.

Q. After Parties presented their positions in opening testimony, how did PGE reply?

A. We responded by emphasizing that PGE seeks to provide customers with optimal value for these plants as they pay for them. Consequently, if the Parties prefer to incorporate the ITC value into the revenue requirement as a rate base offset, PGE would accept their proposals. We then included the ITC into PGE revenue requirements for both Constable and Seaside in this manner, as provided in PGE's workpapers to PGE Exhibit 1300.

Q. What testimony has now been provided by the parties on this matter?

A. Staff provides no additional thoughts on the ITC. CUB now supports returning Constable and Seaside ITC sale values to customers over the asset's lifetime "but financed against rate base"[24] within PGE's revenue requirement. AWEC reiterates that PGE must opt-out of ITC normalization, but they have updated their proposal on the treatment of the ITC by now stating that the ITC should be spread over a five-year period. Further, they are claiming that PGE has made a new proposal to discount the ITCs by ten percent.[25]

Q. Does PGE oppose opting out of normalization?

A. No. PGE has reviewed the information regarding this topic, and does not believe we need to opt out of normalization if we are selling the credits. It is PGE's understanding from review of the IRS publication of 26 CFR Part 1 [TD 9993], that when a taxpayer sells tax credits, they are no longer subject to normalization rules for those credits, which effectively bypasses the need to opt out of any specific accounting treatment.[26] However, if such an opt out is required, PGE agrees that we would opt out of normalization in order to obtain the treatment of the ITCs as proposed.

Q. How does PGE respond to AWEC's proposed five-year period for spreading the return of the ITC?

A. While we appreciate that AWEC sees value to PGE's initially proposed time period and is now deciding to alter their request, the request is now disconnected from that proposed by both Staff and CUB. Furthermore, AWEC's proposal is disconnected from the standard

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[24] CUB/500, Tran/3, at 9.

[25] AWEC/300, Mullins/44-46.

[26] *See* https://www.federalregister.gov/documents/2024/04/30/2024-08926/transfer-of-certain-credits. "[T]he Treasury Department and the IRS clarify that an eligible taxpayer is not subject to the normalization rules with respect to any cash consideration paid by a transferee taxpayer for a specified credit portion that is described in section 6418(b)(2). Any portion of an eligible credit that is not transferred, however, would remain subject to the normalization rules as applicable.

treatment of assets included in base rates. AWEC's proposal differs from PGE's initial plan, which was tied to the Seaside tracker and front-loaded the ITCs with gradual annual reductions through a supplemental schedule that would be updated annually to prevent a sudden price increase for customers. AWEC's proposal appears to opportunistically create a mismatch in base rate treatment of these assets in which, for depreciation purposes, the asset value is recovered over the life of the asset but the reduction of expense and rate base associated with the credit value is compressed into a much shorter time period.

Q. Is PGE changing its proposal again?

A. No, we are not changing our proposal again, as we have already done so once to create alignment with the Parties. The current treatment included in this surrebuttal testimony maintains alignment with Staff and CUB's current positions, which includes the ITC within the revenue requirement of the plant as a decrease to tax expense and to rate base that is amortized consistent with the depreciable life of these assets.

Q. Regarding the discount to the value of the ITC up to ten percent for the costs associated with selling the credits, is this a new proposal as claimed by AWEC?

A. No. PGE Exhibit 500, an exhibit filed with PGE's opening testimony on February 29, 2024, clearly identifies the ten percent discount factor and recognizes that it is based on the same set of factors agreed upon previously by Parties to sell production tax credits.[27] AWEC's proposed departure from the previously agreed-upon treatment of credit sales actually represents a new position, and they failed to provide a compelling rationale for changing this approach now that PGE is selling ITCs instead of PTCs.

[27] PGE/500, Felton/31.

Q. What does PGE recommend of the Commission regarding the treatment of ITCs?

A. PGE recommends the Commission adopt PGE's proposal as presented in PGE Exhibit 1300 and clarified here, which is consistent with the proposals of Staff and CUB. To be clear, the value available to provide to customers would be the actual value received for the ITCs, which will be the face value of the credits net of a discount and/or costs to sell the credits. As stated in PGE Exhibit 500, the combined discount and/or cost to sell the credits cannot exceed ten percent of the face value of the credits. This proposal is consistent with the treatment approved by the Commission for the sales of PTCs in Order Nos. 23-459 and 24-106.

V. Anderson ITCs

Q. What is AWEC's position on ITCs associated with the Anderson Readiness Center (Anderson)?

A. AWEC continues to disagree with our treatment of these ITCs within the test year revenue requirement. Specifically, AWEC argues that PGE should reflect this ITC benefit within its revenue requirement because "it will be able to utilize tax credits associated with the Anderson Readiness Center in 2025"[28] and regardless, "the Commission has full authority to begin amortization of these ITCs because PGE agreed to opt out of normalization."[29]

Q. Has PGE modified its position from reply testimony on these credits?

A. Yes. As we stated in reply testimony, PGE will opt out of normalization for this credit and we continue to assert that PGE does not currently have the tax appetite to utilize this credit. However, following additional research and consultation with third-party experts, it is PGE's understanding that when normalization rules do not apply, the GAAP deferral method requires ITC amortization to begin when an asset is placed in service and continues over the life of the asset.[30] Based on this current understanding, PGE proposes the following treatment within the test year to begin reflecting this benefit within customer prices, which is reflected in PGE's updated revenue requirement provided as PGE Exhibit 2401:

- An amortization credit amount of $49,344, reflected as a reduction to tax expense, which represents 1/10th of the ITC;
- A deferred credit within rate base of $415,308,[31] to reflect the unamortized deferred ITC as of December 31, 2024; and

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[28] AWEC/300, Mullins/42, at 18-19.
[29] *Id*. at 19-20.
[30] *See* PGE's response to AWEC Data Request No. 167, provided here as PGE Exhibit 2402 for additional detail.
[31] $415,308 = $493,436 less 2024 amortization ($49,344) and 2023 amortization ($28,784).

- An offsetting increase to rate base of $493,436 for the Deferred Tax Asset associated with the unutilized ITC as of December 31, 2024.

The deferred credit will amortize, straight-line over the depreciable life of the asset, while the deferred tax asset would decline based upon PGE's ability to utilize the credit within its tax return, which we do not currently forecast to occur in 2024.

VI. Accumulated Deferred Income Taxes (ADIT)

A. PTC Carryforwards

Q. Did PGE include an adjustment to its filed PTC carryforward balance in reply testimony?

A. Yes. PGE included a $53.4 million reduction to rate base to reflect its most current assumption of $35.7 million of PTC carryforwards at December 31, 2024.

Q. What was AWEC's response to PGE's adjustment?

A. AWEC continues to argue for the entire removal of this balance from PGE's rate base, which amounts to an additional $35.7 million reduction.

Q. Does AWEC state a disagreement with PGE's revised December 31, 2024 carryforward balance?

A. No. AWEC does not indicate agreement or disagreement with the balance PGE forecast on December 31, 2024.

Q. If AWEC does not refute PGE's revised year-end forecast of $35.7 million, what is their argument for removing the entirety of PGE's balance?

A. AWEC argues that PGE has demonstrated that "it expected the balance to decline to zero in 2025."[32]

Q. Does PGE currently expect its carryforward balance to decline to zero in 2025?

A. No. PGE's 2025 balance will be largely dependent on the actual number of PTCs PGE can utilize in 2024 and 2025. Currently, we do not anticipate the ability to fully extinguish this balance in 2025. More importantly, AWEC is cherry-picking time periods for rate base to lower PGE's request in this case.

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[32] AWEC/300, Mullins/39 at 8-9.

Q. Please explain.

A. AWEC is selectively arguing for different points in time in calculating PGE's rate base depending on what generates the largest reduction. For PGE's plant amounts, AWEC argues for an average-of-monthly-averages of amounts beginning in January of 2024—a full twelve months *prior* to PGE's rate effective date. This artificially reduces PGE's test-year plant in service amounts below amounts that will be in service to customers during the test year. For PGE's PTC carryforwards, AWEC effectively argues for the exact opposite treatment, with a point in time balance at the end of 2025—a full year beyond PGE's rate effective date.

Q. Is PGE's 2025 PTC carryforward balance relevant?

A. No. Setting aside the fact that PGE still currently expects a balance on December 31, 2025, PGE's rate base is established as of December 31, 2024.

Q. Does AWEC argue that any other areas of PGE's rate base be updated to reflect 2025 expectations?

A. No. AWEC appears to self-select only one minor component of PGE's rate base that may experience a decline in value between rate cases.

Q. Do customers continue to receive the rate base benefit of removing PTC carryforwards between rate cases?

A. Yes. Customers are currently receiving a benefit in 2024 and will experience an even greater benefit for 2025. These benefits are not simply accrued to customers for one year. Rather, the benefits continue to accrue to customers for every year following their removal from rate base until the point at which PGE would have otherwise been able to utilize the credit without a sale. As an example, PGE removed approximately $32.1 million of carryforwards from UE 416 because PGE was able to sell these credits on behalf of customers. This amounted to an approximate $2.9 million reduction to base rates in 2024 and compared to the status quo prior to PGE's ability to sell these credits, customers benefit from this sale in 2025 and 2026. This is because, without the sale, PGE would not be able to utilize these credits in 2024 or in 2025. The same is true for the approximate $58.4 million of 2024 generated PTCs PGE is removing from this case.[33] Customers will see an over $5 million reduction to base rates for 2025 and will benefit in 2026 and beyond compared to the status quo prior to PGE's ability to sell these credits.

Q. Are there any other issues with AWEC's proposed adjustment?

A. Yes. AWEC's proposed adjustment assumes a total PTC carryforward amount that is greater than amounts included by PGE at any stage in this proceeding. AWEC's adjustment assumes that PGE included $107.5 million of PTC carryforwards in its initial filing. However, as we provided in PGE Exhibit 1300, Table 6, PGE's initial filed PTC carryforward balance was only $89.1 million and our current revised request includes a balance of $35.7 million.

Q. What action does PGE recommend the Commission take regarding its test year PTC carryforward balance?

A. We request the Commission decline to adopt AWEC's recommendation and instead adopt PGE's proposal to include $35.7 million of PTCs in rate base. PGE's revised PTC balance as filed in our reply testimony and included within our currently filed revenue requirement includes customer benefits resulting from the sale of 2023 and 2024 PTCs and is the most accurate projection of PGE's balance at December 31, 2024.

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[33] $58.4 million is the forecast amount of 2024 generated PTCs included in PGE's initial request, while $53.4 million is the net impact of adjustments included in PGE Exhibit 1300, Table 6.

B. Major Storms ADIT

Q. What is AWEC's proposal associated with PGE's 2020 emergency wildfire and 2021 ice storm deferrals?

A. AWEC recommends that PGE include an ADIT benefit within this case associated with these deferred balances, which AWEC calculates as a $26.1 million reduction to rate base using a December 31, 2023 deferral balance. In support, AWEC argues that the timing between deferring these amounts in 2020 and 2021 and the ultimate collection of costs from customers over a seven-year period, results in a favorable deferred tax benefit due to the treatment between book and tax accounting.

Q. Does AWEC correctly characterize PGE's reply testimony?

A. No. While AWEC touches upon the fact that the amortization of these deferred amounts has an adopted stipulation, they appear to miss the point made by PGE that these have been handled outside of PGE's base rates. Additionally, AWEC neglects to mention the conflict in their arguments, which PGE highlighted in reply testimony.[34]

Q. Does PGE agree with AWEC's response that unless ADIT was specifically addressed in Commission Order No. 22-435, it is still an open issue to be addressed in this proceeding?

A. No. As we directly referenced in reply testimony, the Stipulation adopted in Commission Order No. 22-435 resolved "<u>all</u> [emphasis added] issues related to the 2021 deferred costs for the wildfire and ice storm events."[35] Additionally, parties to the Stipulation represented that the Stipulation was a compromise between the parties.

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[34] PGE/1300, Batzler-Meeks/38.

[35] *In the Matter of Portland General Electric Company Application for Authority to Amortize Deferred Amounts Related to 2020 and 2021 Emergency Events*, Docket UE 408, Order No. 22-435 at 2, Section III (Nov. 3, 2022).

Q. Does PGE see any inconsistencies in AWEC's argument for consideration of these amounts and AWEC's arguments elsewhere regarding ADIT?

A. Yes. AWEC argues that PTC carryforwards should be removed on the basis that these amounts are "considered outside of revenue requirement,"[36] while simultaneously arguing that these unrelated storm deferral amounts must now be included in rates. PGE discussed this conflict in response to AWEC's positions in our reply testimony.[37]

Q. Did AWEC address this inconsistency in their rebuttal testimony?

A. No, AWEC did not address this inconsistency in their rebuttal testimony.

Q. Would including an ADIT amount in base rates while the regulatory assets are not included in base rates create a mismatch?

A. Yes. Including a credit in rate base without the corresponding debt would create a mismatch in timing and a mismatch of interest rates.

Q. Do you have any further comments regarding this ADIT deferral issue?

A. Yes. PGE has already written off substantial amounts associated with this deferral and is therefore not fully recovering its costs associated with these emergency events. Specifically, PGE absorbed all amounts associated with 2020 costs, which totaled approximately $14.5 million.

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[36] AWEC/100, Mullins/51 at 2.
[37] PGE/1300, Batzler-Meeks/35.

VII. Cash Working Capital

Q. Please summarize Staff's rebuttal testimony regarding PGE's cash working capital (CWC).

A. Staff's rebuttal testimony accepts PGE's position regarding the estimate of service lag and withdraws their proposal to adjust PGE's CWC factor. However, Staff continues to disagree with PGE's inclusion of depreciation and amortization (D&A) expense in the calculation of CWC, stating that the risk of investment is properly reflected in PGE's return on equity (ROE). Additionally, Staff argues that CWC is not the "proper mechanism" for addressing D&A lag.[38] Finally, Staff argues that PGE has not demonstrated that including D&A expense in the calculation of CWC is a proxy for the fact that PGE has not included debt expense payments within its lead lag study.

Q. What is CWC supposed to represent?

A. PGE's CWC is supposed to cover the gap between when expenses are incurred and when revenues are collected.

Q. How does D&A fit into this concept?

A. As we stated in reply testimony (PGE Exhibit 1700), the rate base in this case is credited with the full year of D&A expense included in this case. In other words, PGE's rate base assumes that this D&A expense has been recovered from customers on day one of the rate effective date. However, the actual recovery of this D&A expense will occur <u>over</u> the test period, creating a gap between when PGE has incurred the expense (i.e., the day one reduction to rate base) and collected the revenue. Thus, there is a short-term gap between revenue and expense.

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[38] Staff/2700, Chipanera/10.

Q. Is this lag between the reduction to rate base and collection of D&A expense reflected in PGE's ROE?

A. No. There is no assumption of this lag in the calculation of PGE's ROE. PGE can find no instance of this real lag between collection and reflection of D&A expense being discussed or contemplated in any ROE calculation by PGE or parties. Furthermore, the return PGE earns is on rate base, which is reduced by the D&A expense to be collected. Thus, a return is not being earned on D&A expense.

Q. Can the lag on D&A expense be determined differently?

A. Yes. Rather than including D&A expense in the calculation of total working cash as PGE has done, another way of factoring in the expense lag on D&A expense is to include it within the lead-lag study. Since book D&A expense is occurring uniformly day by day and accumulated D&A is deducted from the rate base, this is typically done by including D&A in expense with zero lag days.[39] Had PGE included the test year D&A expense within its lead-lag study and thus not used D&A expense in the calculation of working capital, the working cash factor would have increased from 4.22% to 5.72% and PGE's working capital requirements inclusive of Constable would be approximately $115.7 million vs. the $105.8 million included in our request.

Q. Is PGE advocating for the inclusion of debt expense payments into its lead lag study?

A. PGE is still investigating this and may propose this within a future proceeding. However, the point we made in PGE Exhibit 1700 is that not only does the inclusion of D&A expense in the calculation of CWC compensate PGE for the lag between reflecting and recovering D&A

[39] See California Public Utilities Commission Water Division, Determination of Working Cash Allowance (March, 2006) https://docs.cpuc.ca.gov/published/REPORT/83068.htm#P498_25865, Chapter 3, part F-Determination of Expense Lag Days.

expense, it also serves to compensate PGE for the lag between incurring and servicing its interest expense, which is not currently included in the calculation of PGE's CWC factor.

Q. What does PGE recommend?

A. PGE recommends no change to the calculation of CWC amounts included in rate base. Alternatively, should the Commission have concerns with what is included within PGE's lead lag study or the amounts used to calculate CWC, PGE supports the review by an outside expert prior to filing of PGE's next general rate case.

VIII. Operating Materials and Fuel Stock

Q. Please summarize PGE's cost recovery request concerning operating materials (i.e., materials and supplies) and fuel stock in this case.

A. PGE seeks to recover the return on approximately $101.7 million associated with materials and supplies and fuel stock. This includes approximately $77.5 million associated with materials and supplies, $14.5 million associated with natural gas fuel stock at North Mist and approximately $7.5 million associated with Beaver oil fuel stock. We note that PGE previously agreed to remove the CO2 allowances fuel stock from this case in reply testimony.

Q. Please summarize Staff's rebuttal testimony regarding PGE's fuel stock.

A. Staff continues to argue for reduced valuations of PGE's natural gas and oil fuel stocks, albeit with some supplemental justifications. Specifically, Staff continues to recommend:

1. That an average balance be used to value PGE's natural gas fuel stock, for a reduction to PGE's rate base of $2,121,786;[40]
2. That PGE maintains too much natural gas for reliability purposes and recommends PGE conduct an analysis to show the economic value of holding a minimum of 1.2 million dth of natural gas at North Mist;[41]
3. That fuel stock be valued at "the actual purchase price at the time of purchase[;]"[42]
4. That PGE oil stock be valued at current spot oil prices for a reduction to PGE's rate base of $1,592,608;[43]

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[40] Staff/3600, Dyck/9-11.
[41] *Id.* 12-13.
[42] *Id.* 15 at 5-6.
[43] *Id.* 18-20.

5. That oil stock for Beaver be devalued on the mistaken assumption that Beaver will lose its oil burning capability in 2025, thus urging a fifty percent disallowance for an additional reduction of $2,964,020.[44]

Q. Did Staff advance new arguments in support of the above proposed adjustments?

A. Yes. Staff attempted to provide additional support for their above adjustments and recommendations in rebuttal testimony. We respond to Staff's new arguments concerning PGE's natural gas and oil fuel stock below.

A. Natural Gas

Q. Staff continues to recommend using an average balance of fuel stock for PGE's test year valuation. Has PGE explained why it uses a December 31, 2024 balance in rate base?

A. Yes. We use December 31, 2024 for consistency purposes as this is the point in time we value all other items in rate base and is one day prior to the start of PGE's test year. Additionally, this represents the forecasted starting balance of PGE's gas reserves in service to customers during 2025, PGE's test year.

Q. In their rebuttal testimony, Staff states that the fuel in rate base is somehow different than the fuel used in PGE's power cost forecast, suggesting that this warrants differing valuations.[45] Are they different as Staff suggests?

A. No. It is the same fuel. That is the point of PGE using the gas storage modeling workbook from the AUT. It directly links the stored gas utilized in power costs to the stored gas included in rate base. We discuss this further below.

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[44] *Id.* 21-22.
[45] *Id.* 10.

Q. Staff now argues that PGE's ability to recover eighty percent of reliability contingency event (RCE) costs that exceed the RCE forecast supports an adjustment to natural gas volumes in the test year. Does the ability to recover RCE costs support the reduction of PGE's fuel volume in rate base?

A. No. The fact that PGE has no-notice stored gas[46] to call upon, which can be filled during lower priced periods, serves to potentially increase PGE's reliability and reduce actual power costs. That is, while RCEs result in higher power costs to serve customers and a greater risk to PGE's ability to reliably serve load, PGE's stored gas can serve to mitigate both costs and risk. PGE also disagrees with Staff's general characterization of the RCE mechanism. PGE can face extraordinary challenges in meeting customer load reliably during periods of load excursions and extreme weather events. The RCE mechanism, which is based on clear objective criteria, allows for PGE to recover the prudently incurred costs in responding to these events on customers behalf.

Q. Staff now appears to suggest that, because PGE has managed pipeline disruptions in the past without access to gas at North Mist, it is reasonable to reduce the total value in fuel stock.[47] How do you respond?

A. PGE disagrees with this conclusion for several reasons. First, the event cited by Staff occurred when PGE still had the Boardman coal plant in our resource stack. Boardman provided 518 MW of capacity that was not reliant on gas pipelines or weather that no longer exists. Second, while PGE did not yet have the no-notice storage and rights at North Mist, we had certain storage rights at Mist, which are no longer available.[48] Third, PGE's actual more recent

[46] PGE can withdraw gas at North Mist on a "no-notice" basis, which provides a high degree of intra-day and intra-hour flexibility that aligns with PGE's need for a flexible and dynamic fuel supply.
[47] Staff/3600, Dyck/11.
[48] Mist storage is a different storage facility from North Mist. PGE no longer has rights to the Mist storage facility.

peak winter load is significantly greater than the peak loads seen during the fall and winter of 2018.[49] The fact that PGE was able to effectively respond to this event and avoid shedding customer load does not guarantee the same will be true again, as different crises place different pressures on the system. However, this previous event does highlight the critical importance and benefit of having no-notice stored gas to respond to a potential future event. Of course, gas storage is only useful during reliability events like the one highlighted in PGE Exhibit 1300, pages 49-50, if there is enough gas in storage.

Q. Staff highlights in their rebuttal testimony that PGE modified its gas stock forecasting method to more directly align with the gas modeled in the AUT. Does this fact support Staff's adjustment in any way?[50]

A. No. PGE is perplexed as to the point Staff is attempting to make by highlighting that PGE improved its forecasting method. The alignment of costs and benefits has traditionally been a concept that parties support. While Staff states that this change indicates that PGE's "own past calculations" of gas forecasts were not aligned between the AUT and GRC filings, this statement is irrelevant to the reasonableness of PGE's gas forecasts *in this case.*

Q. Staff expands on their recommendation that PGE perform a financial analysis of gas reserves by stating that "the justification for keeping a minimum balance of [fuel] in reserve should be explained and established."[51] Has Staff reviewed PGE's 1.2 billion cubic feet (BCF) of gas reserves in other proceedings?

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[49] Peak loads from October 2018 through February 2019 were between 2.6 thousand megawatts (MW) (October 2018) and 3.4 thousand MW (February 2019). PGE has seen a higher peak load in every subsequent fall/winter period including recent peak loads from October 2023 through February 2024 between 3.1 thousand MW (October 2023) and 4.0 thousand MW (January 2024).

[50] Staff/3600, Dyck/11.

[51] Staff/3600, Dyck/12, at 13-14.

A. Yes. Since PGE's 2021 AUT proceeding, Docket UE 377 (UE 377), gas storage optimization benefits have been modeled for North Mist and have included the 1.2 BCF of reliability reserves. Staff reviewed PGE's introduction of gas storage optimization prior to and within UE 377 and did not express any issue or concern with this modeling assumption. In fact, no party proposed an adjustment to this reserve amount in UE 377, nor has any party proposed a different treatment in any subsequent power cost proceeding.

Q. Staff also states that PGE "has other options for ensuring that it has enough fuel for generation to meet load other than holding a large amount of natural gas in reserve."[52] Is it clear what they are referring to?

A. No. North Mist is PGE's only gas storage facility and should PGE not retain reliability reserves and gas deliveries become constrained or prices spike, PGE and customers are exposed to higher market costs and reliability impacts.

Q. Staff's rebuttal testimony dismisses PGE's analogy between fuel reserves and home insurance by returning to their previous analogy comparing fuel reserves to a homeowner hiring "an in-house electrician for emergencies."[53] Are these two analogies comparably credible?

A. No. PGE's analogy illustrates the actual relationship between gas reserves and other products that insure against disasters. To be clear, holding fuel reserves *directly insures customers* from both runaway prices *and* supply disruptions. Similarly, homeowners pay for an insurance product to protect their house from disasters and other unforeseen events. In contrast, Staff's fanciful analogy of an "in-house electrician" is used to conjure a specter of unmanageably high costs that far exceed any reasonable market mechanism—the sort of cost that could

[52] Staff/3600, Dyck/12 at 17-19.
[53] *Id*. 13 at 4.

potentially dwarf a household's total annual earnings. Yet holding fuel reserves is a common practice for energy companies and falls within a reasonable and prudent range for insurance against reliability events.

Q. Staff continues to view holding reliability reserves as an economic issue. Is it?

A. Not entirely. While it is important to understand and base the decisions of when to inject and withdraw stored gas on market economics, we must also be mindful of and prepared for the worst-case scenario that the next marginal unit of gas or electricity may be unavailable at any price. The energy market does not have infinite depth and liquidity. Nor is PGE a merchant operator who can decide when it is favorable to meet demand. Our primary function in power operations is to meet and serve our load obligations under any scenario. This includes scenarios where PGE must use every tool at its disposal.

Q. Has PGE altered its position to Staff's recommendation of performing a financial analysis of fuel stock reserves?

A. No. As we stated in PGE Exhibit 1300, PGE is not opposed to reviewing the economics associated with gas reserves, we believe that any financial analysis must recognize that there are essential non-financial reasons to maintain reliability reserves. With this balance in mind, PGE proposes to conduct a workshop with parties prior to the filing of our next AUT to review gas storage modeling in MONET, including the economic and non-economic considerations of results from scenarios prepared with parties' input.

Q. What does Staff recommend regarding the valuation of PGE's gas stock?

A. Staff clarified in their rebuttal testimony that their recommendation is to use historic values for determining the price of PGE's reliability reserve gas. Staff argues that this gas is only intended to be used in emergencies and thus "it makes sense to use historic values because that is representative of the price that PGE paid when it was purchased."[54]

Q. Is there accounting guidance on the valuation of gas stock on a utility's balance sheet?

A. Yes. According to accounting guidance from PricewaterhouseCoopers (PwC), only cushion gas should be classified as part of property, plant, and equipment (i.e., valued at original cost).[55]

Q. Does PGE hold any cushion gas at North Mist?

A. No. Cushion gas is commonly defined as an amount of gas that is permanently stored to maintain sufficient pressure in storage to allow adequate injection and withdrawal rates. There is cushion gas held at North Mist, however, PGE does not own nor have rights to North Mist cushion gas. Northwest Natural is the owner of North Mist and its cushion gas, which is not intended for sale. As such, Northwest Natural does record this gas at original cost. Recording any of PGE's gas at original cost would amount to a material financial misstatement, as it is all classified as working gas that is ultimately expected to be sold or used in operations.

Q. Aside from the accounting implications of valuing certain portions of PGE's gas at "the actual purchase price," are there other reasons why this valuation does not make sense?

A. Yes. Fuel inventory is not like other materials and supplies PGE holds in inventory, which can be individually tagged and identified with a particular purchase price. Stored gas is measured in cubic feet and these molecules comingle with and are indistinguishable from each other, which is a primary reason why weighted average cost is used. The original 1.2 BCF of

[54] Staff/3600, Dyck/14 at 19-20.
[55] "5.2 Physical natural gas storage" US Utilities Guide, PWC Viewpoint (Feb. 23, 2024) https://viewpoint.pwc.com/dt/us/en/pwc/accounting_guides/utilities_and_power_/utilities_and_power__US/chapter_5_natural_ga_US/52_physical_natural__US.html#pwc-topic.dita_1608045108169564

gas that PGE injected into North Mist is not something that is tagged and isolated within the storage facility. Those specific molecules of gas, which were injected between 2018 and 2019, were withdrawn years ago. From North Mist's inception through July of 2024, over 30.8 BCF have been injected into and over 26.2 BCF have been withdrawn from North Mist. That is approximately seven times PGE's total storage capacity over less than six years of North Mist being placed into service. Thus, the stored gas that PGE relies upon now is not the same physical gas that was historically purchased.

Q. Staff attempts to make a distinction between PGE's gas in fuel stock versus gas in power costs. Are they two separate items?

A. No. The gas in our fuel stock is the gas held at North Mist, which is the gas modeled in PGE's power costs and used in reality to fuel our westside thermal generating stations. Additionally, there are not two different ways of valuing this gas; it is all valued at WACOG. While there is a portion of stored gas in PGE's power cost forecast that is forecast, it is based upon specific volumes of injection and withdrawal, at forecast prices paid, all of which inform the total WACOG value. Staff is correct that these prices are variable, but they all inform the total WACOG, which is updated with every subsequent injection and withdrawal.

B. Oil

Q. Please briefly summarize PGE's position concerning cost recovery of oil stocks.

A. As we explained in reply testimony, PGE values its oil stocks using the weighted average cost (WAC). While PGE compares existing balances to lower of cost or market (LCM), LCM is used to confirm that the WAC is not materially above current market levels.[56] For instance, PGE recently compared its oil WAC to NYMEX heating oil futures contracts, which are

[56] PGE/1300, Batzler-Meeks/51.

actively traded on commodity exchanges. We discuss the results of the NYMEX comparison later in our testimony.

Q. What is Staff's position concerning PGE's oil stock?

A. Staff continues to argue that PGE's oil stock is overvalued, on the basis that NYMEX heating oil futures are not the right comparison, and that Energy Information Administration (EIA) data concerning crude oil prices is a more appropriate comparator.

Q. Is the EIA data concerning crude oil prices an appropriate comparator for PGE's oil stock values?

A. No. Staff is relying on a price index for the wrong kind of oil. The index Staff used for their comparison was crude oil. However, this is not comparable to the oil used to fuel the Beaver facility. Crude oil is an unrefined petroleum product that is typically refined into gasoline. The commodity index that aligns with the oil Beaver uses to generate electricity is No. 2 Heating Oil,[57] which is the benchmark PGE compared from NYMEX and is an index included within the EIA data Staff references. Using the EIA data, the price per gallon of No. 2 Heating Oil averaged $3.57 per gallon for 2022 and $2.68 per gallon for 2023. This compares to PGE's actual WAC for oil of $2.49. Thus, when using the NYMEX information PGE provided in PGE Exhibit 1300 or the correct EIA data cited by Staff, PGE's WAC is below market.

Q. Are there any other variables included in PGE's WAC for oil that should be highlighted?

A. Yes. One other variable included in the WAC of PGE's oil is transportation costs. While we have demonstrated above that PGE's WAC is below the price per gallon of the No. 2 Heating Oil index, we feel it is important to mention that any index price does not include the cost of transportation, whereas PGE's WAC does and should include this cost.

[57] No. 2 Heating Oil is very similar to diesel fuel.

Q. If PGE's WAC for oil is below market, shouldn't PGE be able to sell this oil at its WAC?

A. It depends on the market price of oil. PGE is attempting to sell this oil on the secondary market. PGE is not an oil distribution company. There is a limited set of buyers who are willing to purchase oil on the secondary market, with the most likely purchaser being an oil distribution company. As such, any company will likely need to factor in costs associated with obtaining the oil and a margin that makes it worth transacting.

Q. PGE previously highlighted that Staff's two proposals for valuing gas (at its actual price) and oil (at a market price) are in conflict. How did Staff respond?

A. Staff responded by stating that different valuation measures are appropriate because PGE values these commodities differently.

Q. Does PGE's valuation of gas and oil stocks support using market values for one and actual values for the other?

A. No. PGE's valuation of gas and oil stocks both rely on the WAC. As PGE has repeatedly noted, the LCM method is used as a benchmark check – not a valuation method. As we stated in PGE Exhibit 1300, all of PGE's fuel stock is valued using WAC and GAAP requires consistency of inventory costing. This contrasts with Staff arguing for original cost for a subset of PGE's gas, WAC for another subset of PGE's gas, and market value for PGE's oil stock.

Q. Staff asserts that "if PGE is purchasing its oil for the value that it claims, it is purchasing it at a much higher cost than market."[58] Is this correct?

A. No.

[58] Staff/3600, Dyck/19 at 19-20.

Q. Relying upon out-of-date information, Staff previously recommended a reduction in the amount of PGE's oil stock based on the assertion that not all of the oil will continue to be used and useful. After PGE provided support in reply testimony[59] for the fact that Beaver will still have the ability to utilize this oil in 2025, did Staff revise their recommendation?

A. No. While PGE pointed Staff to our response to OPUC Data Request No. 507, indicating that oil at Beaver will be phased out in 2026 and not in 2025, Staff chose to ignore this more current information and continue to rely upon an out of date set of facts.

Q. How did Staff respond to PGE's assertion they were relying upon outdated information?

A. Rather than address the more updated information provided in PGE's response to OPUC Data Request No. 507, Staff chose to reemphasize their position based on outdated information from February 2021.[60]

Q. Is there more current information within Staff Exhibit 1403 supporting PGE's statement that oil will be phased out in 2026?

A. Yes. Within the same exhibit Staff uses to justify their position, a more recent justification update from May 2023 (Justification -10 of Staff Exhibit 1403) indicates a 2026 in-service date for the final Beaver turbine upgrade.[61]

C. Materials and Supplies

Q. Please summarize Staff's rebuttal testimony regarding materials and supplies?

A. Staff's rebuttal testimony continues to argue that PGE should be using a three-year historical average of monthly materials and supplies balances for 2021-2023 and arrive at a total by

[59] PGE/1300, Batzler – Meeks 51-53.
[60] Staff Exhibit 1403, Dyck/2.
[61] Staff/1403, Dyck/13.

escalating that average to 2024 using All-Urban CPI. Staff supports this method by arguing their methodology is "consistent with how Staff has historically forecast this component of rate base."[62] Further, Staff argues the PGE "does not explain what methodology it uses to arrive at its forecast, nor does it provide evidence to substantiate that its forecast balance accurately anticipates future operational needs and procurement costs."[63]

Q. What support did PGE provide for its materials and supplies balance?

A. In our reply testimony[64] and as provided in PGE Exhibit 1305, we demonstrated that PGE's actual balance for materials and supplies as of June 30, 2024 was approximately $6.1 million greater than amounts included in this case.[65]

Q. Does Staff address this key fact and support for the reasonableness of PGE's test year balance in their rebuttal testimony?

A. No. Staff neither mentions nor addresses the fact that PGE's actual balance is currently greater than the amount included in this case.

Q. Does PGE provide reasons for the documented increase in its materials and supplies balance?

A. Yes. As PGE Exhibit 1300 explains, the increase is due to substantial growth and inflation associated with the underlying transmission and distribution materials and supplies, including over thirteen percent annual inflation for poles and transformers.

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[62] Staff/3900, Moore/2 at 20-21.
[63] Staff/3900, Moore/3 at 4-6.
[64] PGE/1300, Batzler-Meeks/54-56.
[65] As provided in PGE Exhibit 1305, PGE's June 2024 ending balance is approximately $84.6 million, while the amount reported in SDR 084-A and included in PGE's test year rate base is $78.5 million.

Q. How did Staff address this support and data provided from PGE?

A. While Staff mentioned the T&D information provided by PGE,[66] they simply responded by disagreeing and offered no further explanation.

Q. Is PGE aware of any historical precedent in which Test Year materials and supplies balances were forecast for rate making purposes in the method that Staff recommends?

A. No. PGE is unaware of this method ever being explicitly used in rate making and Staff, through discovery,[67] was unable to identify any Commission Order requiring this approach.

Q. Is a three-year historical average a more accurate way of calculating PGE's Test Year materials and supplies balance than comparing to the actual current balance?

A. No. A three-year average of balances using an inflation rate that is not indicative of the actual materials and supplies PGE must maintain, and in no way approximates or suggests a reasonable future Test Year amount as Staff contends. This mismatch is particularly true when PGE has demonstrated that the current actual balance is higher than what was forecast for inclusion in this case—a point that Staff did not even address.

Q. What is PGE's recommendation on this issue?

A. PGE recommends that the Commission reject Staff's proposed three-year historical average approach and find that the amounts included in PGE's case are prudent. Materials and supplies for PGE's T&D operations have grown as PGE's system has grown and the cost of these supplies has been subject to extreme levels of inflation that have significantly outpaced core inflation amounts. Most importantly, PGE's current actual balance for materials and supplies is greater than amounts forecast in the future test year.

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[66] Staff/3900, Moore/2.
[67] See PGE Exhibit 2403.

IX. Other Revenue – Joint Pole and Steam Revenue

Q. Please summarize Staff's rebuttal testimony regarding other revenue.

A. Staff's rebuttal testimony agrees with PGE's statement that joint pole revenue experienced a significant increase in 2023.[68] However, Staff continues to assert that the increase in 2023 should continue to be included within their three-year average methodology and that "a three-year average is a reasonable increment relative to the historical actuals."[69] Similarly, Staff continues to recommend using a three-year average for steam sales, arguing that PGE's 2025 test year forecast is below any of the previous three years of actual steam sale revenue. As such, Staff continues to recommend that PGE's forecast joint pole and steam sale revenue be adjusted by a total of approximately $2.4 million.

Q. What did PGE include in the 2025 test year for joint pole and steam sale revenue?

A. PGE forecast a total of $16.9 million of other revenue associated with these two items, which is made up of $14.6 million of joint pole and $2.3 million of steam sale revenue.

Q. Has PGE collected an amount of joint pole revenue greater than the $14.6 million forecast in any year other than 2023?

A. No. PGE's annual joint pole revenue collection has been below the 2025 forecast amount in every other year and we do not expect 2025 revenue to grow significantly above amounts recorded in 2021 and 2022, which are $14.2 million and $14.3 million respectively.

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[68] Staff/4000, Abraham/3 at 5-6.
[69] *Id*. at 15-16.

Q. Please explain why the exclusion of 2022 steam sale revenue is a reasonable adjustment to Staff's three-year average of steam sale revenue method.

A. The revenue increase in 2022 is not just an outlier due to the amount being significantly greater than any other period, it is an outlier based upon a significant non-normal event that occurred in 2022, which led to the increased revenue. Specifically, the mechanical failure one of PGE's steam customers experienced to their on-site boiler, which led them to use a much higher than normal amount of steam from Coyote Springs. This is not simply a case of peaks and valleys resulting from more or less usage. This was an extreme event that PGE has not previously seen occur and would not expect to occur within the 2025 test year.

Q. What is PGE's recommendation to the Commission regarding other revenue?

A. PGE continues to recommend the Commission affirm our initially filed other revenue forecast for joint pole and steam sales of $16.9 million. Alternatively, should the Commission agree with Staff's recommendation to use a three-year average, PGE continues to recommend that the 2022 steam sale revenue be replaced by 2020 actual amounts, as the 2022 revenues were elevated due to a specific extreme event that directly impacted one of PGE's customers, which is highly unlikely to occur again. Incorporating this recommendation reduces Staff's total adjustment to other revenue from $2,427,921 to $1,214,534.

X. PGE Grants

Q. What recommendation did Staff make in opening testimony with regards to O&M costs relating to PGE's federal grant funding?

A. Staff recommended the removal of $600,000 in expense that PGE included in the test year for this rate case relating to its federal Grid Edge Computing Grant (Grid Edge),[70] plus a reduction to O&M of $100,000 to reflect ten percent of the 2025 base for the four federal grants PGE has received thus far. Staff's belief is that these expenses may be federally reimbursable and thus should not be charged to customers.[71]

Q. Has Staff modified their recommendation in rebuttal testimony, in response to PGE's reply?

A. Partially. Staff has removed the adjustment of $100,000 regarding the four federal grants PGE has received thus far but continues to recommend removal of $600,000 relating to the federal Grid Edge Computing Grant.

Q. Has Staff acknowledged PGE's argument in favor of retaining the $600,000 related to the Grid Edge Computing Grant in the Company's revenue requirement?

A. No, it does not appear so. Staff states that "[i]n the absence of any supporting information, Staff assumes that all the grants are reimbursable. Staff welcomes the Company to provide supporting information demonstrating whether this is the case."[72] In reply testimony, we explained that while PGE will be eligible for reimbursement of indirect costs and customers will benefit from the resulting reduction in O&M costs, PGE will also incur non-reimbursable O&M (e.g., cost share) in support of the grants.[73] These costs were not included in the 2025

[70] Referred to in Staff's testimony as the Smart Grid Chip Grant.
[71] Staff/1100, Peterson/21-23.
[72] Staff/3800, Peterson/10 at 14-16.
[73] PGE/1300, Batzler-Meeks/60-61.

revenue requirement as they were not yet estimable at the time of our initial filing. Based on progress in grant negotiations, we can now estimate these non-reimbursable costs for 2025. Thus, any reduction in revenue requirement to reflect estimated reimbursable costs should be netted against estimated non-reimbursable costs.

Q. What non-reimbursable costs does PGE expect to incur in 2025?

A. With respect to the Grid Edge Computing Grant in particular, the $600,000 request in the GRC was derived from our best estimate of grant-related costs at the time of filing. Recovery of those costs remains an appropriate inclusion in our revenue requirement. Current estimates based on more mature negotiation of the grant terms, however, mean that we now actually expect to incur approximately $1.7 million in O&M cost share expenses for the grant in 2025, with approximately $737,000 of that total expected to be reimbursable. This results in an estimated net cost of approximately $956,000, after reimbursements – substantially more than the requested recovery.[74] Given this, Staff's proposal to disallow the current request in the GRC is not reasonable.

Q. Has Staff offered other arguments in favor of its proposed reduction?

A. Staff notes correctly that the purpose of applying for and receiving grants is to fund projects that will benefit the Company and its customers and goes on to state that grant projects should be either projects that PGE was considering regardless of the grant so the grant monies "would in the long run reduce revenue requirement, or projects that after a cost benefit analysis the Company considers worth the additional revenue requirement."[75] Staff however "is concerned that PGE is asking the Commission to assume that all the grants it listed in opening testimony

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[74] *See* PGE Exhibit 2404 for detail.
[75] Staff/3800, Peterson/9-10 at 22-1.

will have no financial benefit whatsoever, and thus cannot offset any amount of customer revenues."[76]

Q. How does PGE respond to Staff's testimony?

A. PGE has stated previously that our grants applications are for projects that will benefit customers and are projects PGE was considering regardless of the grant opportunity, so any grant monies received offset costs that would otherwise likely appear in PGE's revenue requirement. That is what will occur here. The Grid Edge Computing project will offer important grid benefits to customers by enabling real-time information at each meter. This will improve the visibility of the electrical system to grid operators, providing detection of potential operational problems and shortening outage times, ultimately helping to anticipate and mitigate the impacts of extreme weather on grid resiliency. However, Staff is ignoring the fact offered in PGE's reply testimony, that these grants still require a non-reimbursable cost-share.[77] This does not negate the fact that customers will benefit from the body of the grant funding. While the cost-share amounts associated with the grants were not fully known at the time of this filing, they can and have been estimated. Yet, Staff ignores those required cost-share obligations in their proposed disallowance for reimbursable costs. Staff is incorrect in claiming PGE is asking the Commission to assume the grants will have no financial benefit. On the contrary, without any basis and while apparently disregarding the information provided in PGE's reply, Staff states that "[i]n the absence of any supporting information, Staff assumes that all the grants are reimbursable."[78] While the estimate of non-reimbursable costs PGE will

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[76] Staff/3800, Peterson/10 at 8-10.
[77] PGE/1300, Batzler/Meeks/60.
[78] Staff/3800, Peterson/10 at 14-15.

incur will likely vary once finally accounted for, it is clearly not reasonable to assume <u>all</u> costs will be reimbursable.

Q. What do you request of the Commission?

A. We respectfully request the Commission reject Staff's proposed reduction of $600,000 in revenue requirement relating to the Grid Edge Computing Grant. Given the reasonable estimates of non-reimbursable 2025 costs now available, which should be netted against the estimate for reimbursable costs, PGE's current request is not adequate to cover our expected cost of service on behalf of customers in 2025 and Staff's proposed reduction is not warranted.

XI. Capital Attestations

Q. Please summarize AWEC's rebuttal testimony regarding PGE's capital attestation proposal?

A. In their rebuttal testimony, AWEC takes exception with our proposal of a fair and balanced capital attestation process for the capital additions in this docket. AWEC details, in their own words, the parameters of our proposal and in one instance, mischaracterizes our proposal.

Q. Does PGE still commit to basing any attestation process on the May 2024 Update?

A. Yes. PGE still supports the idea of basing the process on the capital projects and amounts included in PGE's May 2024 rate case filing update and reviewed in the evidentiary process. These projects have been thoroughly vetted in the record and cost details have been made available for all parties to investigate for prudence.

Q. Is PGE still proposing to include projects placed in service between October 1 and December 31, 2024?

A. Yes. The Q3, placed in service criteria, fits with Parties historic concerns about projects that have expected completion dates near the end of the year and the risk that these projects might miss the price effective date.

Q. Are there additional reasons, PGE feels a Q3, placed in service criteria, is the most appropriate benchmark?

A. Yes. For any project placed in service before October 1, parties have had ample opportunity to ask on the to-date status of projects to assess prudence. An extensive record has been completed year-to-date on all capital project additions included in our May 2024 update. In addition to PGE's testimony, PGE responded to extensive data requests from Staff, CUB and AWEC, which included more than 2,000 pages of information specifically concerning PGE's capital projects and capital investment process.[79]

Q. Why did PGE propose to only include projects with a capital budget more than $5 million in the attestation proposal?

A. PGE suggested this attestation threshold to strike a reasonable balance between rate impact and administrative workload. Using the $5 million threshold for the project attestation, includes 85% of our overall capital request in this case.

Q. What other factors need to be considered when determining a threshold level for projects to include in the attestation process?

A. For the attestation process to be effective, all stakeholders will need to feel confident in the underlying project support to make their decisions on certification and prudency. This support will involve significant work for each individual project, including invoice collection, accounting entries, depreciation calculations, plant transfers, and project review. Attesting Officers will need to understand the variance drivers for each individual project before they affirm to any findings and External parties, including Staff, will need to evaluate each project to ensure the benefits to ratepayers. The project threshold must be considered in the context of all this work for any effective process.

Q. Would PGE consider a lower threshold for capital projects that strikes the balance between rate payer impact and administrative workload?

A. Yes. While PGE still believes a $5 million threshold is the optimal benchmark, to capture a larger percentage of our capital ask in this docket, PGE would be open to a $3 million cut-off. This move would result in a relatively manageable increase in the number of projects

[79] PGE response to Staff DR No. 231, 233, 235-253, CUB DR No. 6-7, and AWEC DR No. 16.

(approximately 20 additional projects) but it would include over 92% of our overall capital ask.

Q. How does PGE's $3 million proposed threshold compare AWEC's $1 million cut-off?

A. Moving the benchmark to $1.0 would dramatically increase the total number of projects to over 100 while at the same time increasing the total dollar ask by less than five percent.

Q. Is PGE still proposing a neutral over/under budget to actual cost position as a fair and balanced approach for any attestation process?

A. Yes. A cost to budget variance neutral process is the best method to capture the inherent and, in many cases, unavoidable differences that occur with any large and complex project. As detailed extensively in our capital attestation proposal, this approach offers a fair and balanced approach for all rate case stakeholders.[80]

Q. Is PGE's capital attestation proposal a review of each individual Capital Project??

A. Yes. Our proposal is a project-by-project specific review, for a subset of our total capital ask, of actual costs versus our ask in the May 2024 Update. We are not, as AWEC asserts in their rebuttal testimony, asking for a complete portfolio wide review of our rate case capital ask.[81]

Q. Does PGE still feel that a one-time, 45-day attestation still strikes the right balance between customer consideration and administrative workload?

A. Yes. A one-time, 45-day attestation process would allow PGE to have finalized transfers to plant accounting while limiting any exposure to ratepayers for plant not in service. Given, what we believe to be a relatively small amount of project variance in comparison to the total revenue requirement and the short amount of time

[80] PGE/1300, Batzler-Meeks/64.
[81] AWEC/300, Mullins/20.

from rate effective date to attestation, we would not expect a significant impact on any particular customer bill.

Q. What is PGE's recommendation as it relates to any possible capital attestation process?

A. While PGE does not agree with the necessity of an attestation process, PGE feels that the parameters offered in our proposal represents a fair and balanced approach.

List of Exhibits

PGE Exhibit	Description
2401	PGE Surrebuttal Revenue Requirement
2402	PGE's response to AWEC Data Request No. 167
2403	OPUC Response to PGE Data Request No. 023
2404	2025 Grant Cost Share Forecast
2405	2024 OMAG 8+4 actuals plus budget

UE 435

Exhibit 2401 has been retained in its native format

August 28, 2024

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Senior Manager, Revenue Requirement

Portland General Electric Company
UE 435
PGE Response to AWEC Data Request 167
Dated August 21, 2024

Request:

Reference PGE/1300, Baltzer-Meeks/33:17-18: PGE states that it "recommends following its policy of applying the Deferral method of accounting for ITCs, in which the credit is utilized prior to being amortized through income:"

a. Please provide all accounting pronouncements and/or literature supporting PGE's position that under the Deferral Method, ITCs must be utilized prior to being amortized to income.
b. Does PGE agree that the Commission can adopt accounting to return the tax expense benefits associated with the Anderson Readiness Center ITCs over any period that it finds to be reasonable, including beginning amortization in this case? If no, please explain.

Response:

a. Below are the supporting citations from the book **Taxation of Public Utilities** that PGE referenced on the utilization for ITC prior to being amortized to income:

   - § 5.06[1][f]: It summarizes FAS 109 requirements treatment by stating "The amortization of ADITC into income must be computed in a manner consistent with the method applicable to the taxpayer under the ITC normalization requirements if IRC Section 46(f). (See Chapter 9.)"
   - § 9.07[3]: "Ratable is determined by considering the depreciable life actually used in computing the taxpayer's regulated depreciation expense for the property for which the ITC is allowed."
   - § 9.07[3]: "**Caution:** in the case of an ITC amount not fully utilized in the tax year that the property is acquired (or earlier carryback years) because of a tax liability limitation, the credit in excess of the limitation is not "allowed"; accordingly no amount of the excess ITC can be flowed through to cost of service or used to reduce rate base. When all or a portion of the ITC carryover is utilized to offset federal

> income tax payable, a ratable portion of the credit can then be flowed-through. The Service ruled privately that the ratable portion is determined by the regulatory life of the property remaining at the point in time the ITC (or a portion of the credit) is actually used by the taxpayer." (See PLR 8326081)

PGE has followed normalization requirements with ITCs and started amortization upon utilization. However, PGE recognizes that, when normalization rules do not apply, the GAAP deferral method requires ITC amortization to begin when an asset is placed in service and continues over the life of the asset. As indicated in reply testimony, PGE will opt out of normalization, if the Commission does not disapprove. In the circumstance of PGE opting out of normalization, PGE will follow GAAP deferral method of accounting, in which ITC amortization aligns with the asset in-service date.

b. PGE is unclear what AWEC means by whether the Commission can "adopt accounting[.]" PGE understands this question as asking whether PGE agrees that the Commission can apply different reasonable amortization periods for any ITC benefits associated with the Anderson Readiness Center. With that understanding, PGE responds as follows: Yes.

Date: September 18, 2024

TO:
Jaki Ferchland
Portland General Electric Company
Manager, Rates & Regulatory Affairs
121 SW Salmon Street, 3WTC-0306
Portland, OR 97204

FROM: Mitchell Moore, Staff

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 435 – PGE Data Request No. 23

PGE Data Request No. 23:

Refer to Staff/3900, Moore/2, where Staff states their method of using a three-year average of monthly averages for calculating test year materials and supplies balances is "consistent with how Staff has historically forecast this component of rate base." Provide docket and Commission order numbers for any and all Oregon general rate case outcomes where rate base balances were established using a three-year historical average.

OPUC Data Response No. 23:

Staff is not aware of any recent Commission decisions specifying the calculation of materials and supplies. Staff made its calculation based upon long-standing Staff practices. Adjustments to rate base balances for non-fuel materials and supplies (FERC 154) in most recent general rate cases have been agreed upon as part of a stipulation. Staff uses the Consumer Price Escalation based on its transparency and long-standing Staff practices.

As of September 24, 2024

	2025 Estimate						
	SALMON	**Wheatridge**	**Hydrogen Hub**	**Grid Edge**	**CTWS**	**DOL Grants**	**Totals**
Capital In-Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -
O&M Cost Share	272,742	144,922	1,999,530	1,692,621	1,987,078	-	6,096,893
Indirect Cost Reimbursement	$ (31,586)	$ (50,138)	$ (71,893)	$ (736,851)	$ (218,234)	$ (23,272)	$ (1,131,974)
Net cost	$ 241,156	$ 94,784	$ 1,927,637	$ 955,771	$ 1,768,844	$ (23,272)	$ 4,964,920

Row Labels	2023 Actuals	2024 FY Budget	2024 (8+4)*	2025 Forecast**
Production O&M	**$ 127,759,085**	**$ 139,459,730**	**$ 141,785,938**	**$ 149,491,849**
Total T&D	**$ 175,411,467**	**$ 208,010,239**	**$ 209,125,508**	**$ 231,297,953**
Total Cust Svc/Accts	**$ 79,885,826**	**$ 100,077,113**	**$ 89,589,030**	**$ 102,666,942**
Total A&G	**$ 219,663,377**	**$ 235,459,803**	**$ 244,607,531**	**$ 221,683,903**
Total OMAG	**$ 602,719,755**	**$ 683,006,886**	**$ 685,108,007**	**$ 705,140,648**

* 8+4 = 8 months of actual costs plus 4 months of current expected budget updated September 2024

**2025 Forecast has not been updated to reflect any adjustments included by PGE in reply or surrebuttal testimony

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 435

Corporate Support & Total Compensation

PORTLAND GENERAL ELECTRIC COMPANY

Surrebuttal Testimony of

Anne Mersereau
Ryan Van Oostrum
Greg Batzler

October 1, 2024

Table of Contents

I. Introduction and Summary

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

A. My name is Anne Mersereau. I am employed by PGE as Vice President of Human Resources, Diversity, Equity and Inclusion. My qualifications appear at the end of PGE Exhibit 300.

My name is Ryan Van Oostrum. I am employed by PGE as Director Controller. My qualifications appear at the end of PGE Exhibit 1400.

My name is Greg Batzler. I am employed by PGE as a Senior Regulatory Consultant in Regulatory Affairs at PGE. My qualifications appear at the end of PGE Exhibit 200.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to respond to the rebuttal testimony from the Staff (Staff) of the Oregon Public Utility Commission (OPUC or Commission), the Oregon Citizens' Utility Board (CUB), and the Alliance of Western Energy Consumers (AWEC) (collectively, Parties) with respect to Total Compensation, IT Capital Additions, and Corporate Support including Administration and General (A&G) expense.

Q. Has PGE, through the testimony process, identified any areas of compromise with Staff regarding Compensation or Administrative and General (A&G) issues?

A. Yes. As testimony will discuss below, PGE and Staff have been able to engage and reach a point of agreement on Staff's proposed adjustments to cyber liability insurance, workers' compensation insurance, directors and officers (D&O) insurance, and health and dental insurance. PGE's acceptance of these proposals results in an approximate $1.0 million reduction to the company's original request. Additionally, in Staff Exhibit 3300 Staff proposes an alternative solution to property insurance that PGE finds acceptable.

Q. Has PGE been able to reach any compromises with other Parties through testimony?

A. No.

Q. What is being proposed by Parties regarding Total Compensation?

A. Staff proposes:

1. A total reduction of PGE's labor expense of $31.9 million, proposals that have remained unchanged since Staff's opening testimony.
2. Two new proposals seeking a reduction of PGE's annual incentives program of $7.7 million and a complete removal of PGE's stock incentives program.
3. An updated proposal seeking a reduction of PGE's health and benefits expense by $0.485 million.

AWEC continues to propose:

1. A reduction of PGE's labor expense of $34.2 million.
2. The total removal of PGE's stock incentives program from revenue requirement.
3. A reduction of $4.7 million related to incentives overheads.

PGE notes that CUB's compensation related proposals are functionally identical to Staff's second proposal, referenced above, to reduce PGE's annual incentives program and remove stock incentives from revenue requirement. These proposals remain unchanged since CUB's opening testimony.

Q. Please summarize PGE's response to these proposals.

A. PGE responds as follows to the issues listed above:

1. Both Staff's and AWEC's proposals to decrease PGE's total labor expense are unwarranted and lack sufficient justification. PGE requests the Commission reject both proposals as PGE's testimony and evidence presented in this proceeding

demonstrate that PGE's 2025 test year forecast for labor expense is conservative and represents known and measurable expenses with modest escalation from 2023 actuals.

2. PGE urges the Commission to reject Staff's and CUB's unwarranted proposals regarding PGE's annual cash incentive. While Staff cites Commission precedent in their new proposal, the most recent Commission decisions actually support the ratio of recovery PGE seeks for its Annual Cash Incentive (ACI) plan.

3. PGE requests that the Commission reject Staff's, AWEC's, and CUB's proposals to eliminate stock incentives, as these recommendations are unfounded. These parties' attempts to remove this long-standing, key component of PGE's total compensation package are based on the misguided assumption that PGE's interests are fundamentally opposed to those of its customers. PGE will address this misconception in the testimony that follows.

4. Finally, AWEC's proposal relating to incentives overheads is misinformed and should be rejected. PGE will continue to support the validity of its accounting practices, in accordance with precedent and prior stipulated agreements, that provide accurate and appropriate recovery of this expense.

Q. What is being proposed by Staff regarding IT Capital Additions?

A. Staff continues to propose:

1. A rate base reduction of $3.3 million related to two blanket projects, Network Fitness and CTO Desktop Fitness.

2. That two non-blanket projects, Zero Trust and EMS Upgrade, be allowed into rate base at the lesser of the actual expense or the original forecast, and that they be subject to an attestation.

Q. Please summarize PGE's responses to these proposals.

A. PGE responds to the issues listed as follows:

1. PGE has amply demonstrated the prudence of these projects, and as such PGE supports its original forecast and requests the Commission reject Staff's proposed reductions.
2. Regarding the Zero Trust and EMS Upgrade projects, PGE finds this proposal to be functionally identical to other attestation-related proposals. PGE responds to attestation related proposals in Exhibit 2400.

Q. What is being proposed by Parties regarding Corporate Support?

A. Staff continues to propose:

1. A reduction of $1.78 million related to FERC Account 921.
2. A reduction of $5.4 million across PGE's insurance programs, including property, casualty, and Directors and Officers (D&O) coverage, as well as an adjustment related to credits associated with these policies. These proposals include updated adjustments for cyber liability, workers compensation, and D&O insurance that are reflective of updated market projections that Staff relies on.
3. A reduction of $301,984 to PGE's memberships expense.

Q. Please summarize PGE's responses to these proposals.

A. PGE responds to the above proposals as follows:

1. PGE recommends the Commission reject the proposal related to FERC Account 921, as Staff's reasoning does not align with PGE's projections of the future.

2. PGE finds many of Staff's updated insurance-related proposals to be acceptable, however, PGE asks the Commission to reject the portion of this adjustment that relates to General & Auto Liability. This $4.4 million reduction is based upon flawed data and is not reflective of the current excess liability market specific to the utility industry.

3. PGE asks the Commission to reject Staff's proposed adjustment to membership expense. Testimony below will show that much of Staff's proposal is based upon a misunderstanding of the data PGE provided.

Q. What is being proposed by AWEC regarding Corporate Support?

A. AWEC continues to propose:

1. A reduction of $4.6 million to PGE's A&G expense.

2. A 90/10 sharing scheme related to D&O expense, wherein PGE would pay the larger portion.

3. The removal of certain fees from revenue requirement entirely, including revolver fees, margin net interest, and broker fees.

Q. Please summarize PGE's response to these proposals.

A. PGE responds to the above proposals as follows:

1. PGE asks the Commission to reject AWEC's proposal to reduce A&G expense. AWEC asserts they were unable to fully analyze this expense; yet, as highlighted in testimony below, PGE has provided all relevant data promptly. AWEC asserts no claims of imprudence in this matter.

2. PGE asks the Commission to reject AWEC's proposal to split D&O expense because this expense is not only prudent and in customers' best interest, but is also a legal and regulatory requirement.

3. PGE asks the Commission to reject AWEC's proposals on revolver fees, margin net interest, and broker fees. PGE recovers these expenses properly and in accordance with stipulations to which INCU, now AWEC, was a signatory.

II. Total Compensation

A. Labor Costs

Q. Please summarize Staff's rebuttal testimony relating to labor costs.

A. Staff continues to support both of their labor expense adjustments brought forward in their opening testimony, including a $3.8 million reduction related to wages and salaries and a $28.1 million reduction related to FTEs, citing Commission precedent on these matters. Staff also explains at length why they believe PGE's contract labor adjustment was inappropriate and was reversed in their analysis stating, "it is appropriate to analyze PGE's in-house and contract labor needs separately and in consideration of recent historical actuals related to each category."[1] In regard to their FTE adjustment, Staff denies that their $28.1 million dollar adjustment is excessive and unfounded, pointing to Commission precedent to support their methodology.

Q. Please summarize AWEC's rebuttal testimony relating to labor costs.

A. AWEC continues to support their original adjustment of $34.2 million related to PGE's FTE levels, a number reached by holding PGE to 2023 FTE levels and applying an escalation rate. In doing so, they continue to contend that PGE's labor budgeting process results in inaccurate forecasts. Additionally, AWEC contends that PGE's analysis demonstrating a 4.3% annual growth rate from 2023 through 2025 is flawed and that, when PGE's labor is viewed piecemeal, O&M labor is increasing "significantly higher" than what PGE points to in reply testimony.[2]

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[1] Staff/3300, Yamada/6 at 2-3.
[2] AWEC/300, Mullins/28.

Q. Did either Staff or AWEC analyze PGE's total labor expense in a holistic manner in response to PGE's reply testimony?[3]

A. No, however Staff asserts that they did.[4] Staff rests their belief that their analysis is holistic on the fact that they analyze each individual piece of PGE's labor – they analyze straight-time and over-time labor through their three-year wages and salaries model, they analyze PGE's FTE count, and then they analyze contract labor. Staff claims that their proposal provides a "reasonable overall labor inclusion" while "maintaining the separate and distinct nature of contract labor as compared to in-house labor."[5]

Q. Is this a holistic way of analyzing total labor expense as PGE understands the word "holistic"?

A. No. In fact, the Merriam-Webster dictionary defines holistic as: "relating to or concerned with wholes or with complete systems rather than with the analysis of, treatment of, or dissection into parts."[6] By this definition, analyzing the same topic in three separate ways and in isolation (e.g. the three-year wages and salaries model, FTEs, and contract labor) is not holistic.

Q. Why is it so imperative that PGE view its total labor requirements in a holistic manner?

A. Staff's application of the three-year wages and salaries model and FTE adjustment in this case illustrate PGE's point quite clearly. Staff, after reversing PGE's contract labor adjustment, was able to produce a result from their model that suggested a downward adjustment of $3.8 million. In addition to that, their separate and distinct analysis of FTEs led them to propose an additional and duplicative adjustment of $28.1 million. The resulting $31.9 million

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[3] PGE/1400, Mersereau – Van Oostrum – Batzler/9 at 7-15
[4] Staff/3300, Yamada/6 at 4-6.
[5] Staff/3300, Yamada/6 at 8, 20.
[6] Merriam-Webster Dictionary, "Holistic"
https://www.merriam-webster.com/dictionary/holistic

dollars of adjustments that they propose ignore any savings in contract labor. This type of analysis also allows Staff to ignore the simple fact that PGE's total compound annual growth in total labor cost from 2023 to 2025 is just 4.3%. This forecasted increase is effectively the same as the most recent Oregon Office of Economic Analysis forecasts, which suggest that wages and salaries in Oregon will be subject to a compound growth rate of 4.5% over the same period.[7]

Q. How large of an increase in workforce is PGE forecasting for the 2025 Test Year?

A. PGE's 2025 test year forecast includes an approximate five percent increase in FTEs relative to 2023 actuals. This means that, even while PGE's overall labor costs are increasing at a lower rate than the compound growth rate would suggest for these two years, PGE has been able to further contain costs for customers despite increased workforce needs.

Q. Staff's testimony supports the separation of contract labor and straight-time labor by declaring them "fundamentally different."[8] Does PGE agree?

A. No. Staff quotes PGE's testimony that points to differences and proclaims that as evidence that we are in agreement on this matter,[9] but we are not. Differences in efficiency and training cycles do not make a fundamental difference. Fundamentally, straight-time labor and contract labor are individuals that perform the work PGE needs to do to provide customers with the energy they need to go about their lives.

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[7] OEA. Oregon Economic and Revenue Forecast, September 2024. Table A.2. https://www.oregon.gov/das/oea/Documents/OEA-Forecast-0924.pdf
[8] Staff/3300, Yamada/8 at 4-13.
[9] *Id.*

Q. One of Staff's arguments related to their reversal of PGE's contract labor adjustment centered around the fact that contract labor expense has been decreasing in recent years. How does PGE respond?

A. PGE determines its future test year costs based on forecasted expected spending. While historical data can sometimes inform forecasts, it is not applicable in this instance. More recent data, as seen in Table 1 below, reveals that through August 2024, PGE's contract labor expenditures have reached approximately $46.1 million, significantly exceeding the budgeted amount of $37.6 million. If spending on contract labor continues at this pace, PGE could spend as much as $69.1 million on contract labor, meaning $31.5 million more would be needed than what was budgeted and $8.6 million more than 2023 actuals. Meanwhile, in aggregate PGE is on pace to outspend our 2024 total labor expense budget by only $15.0 million, which implies that approximately $16.5 million has been shifted from straight-time labor to contract labor—a figure that is slightly more than PGE predicted with the contract labor adjustment of $14 million.[10] Additionally, PGE notes that, throughout the period that Staff points to, PGE exceeded its contract labor budget by an average of $24.5 million.[11]

Table 1
PGE and Contract Labor, 2024 Update

	2023 Actuals	2024 Budget	2024 Jan-Aug Actuals	2024 Jan-Aug Actuals + Sep-Dec Budget	2025 Forecast
PGE Labor	$ 372,141,128	$ 403,667,701	$ 258,121,107	$ 394,094,817	$ 416,289,879
Contract Labor	$ 60,479,970	$ 37,572,629	$ 46,066,382	$ 58,576,860	$ 54,082,608
Total	**$ 432,621,098**	**$ 441,240,329**	**$ 304,187,489**	**$ 452,671,676**	**$ 470,372,487**

[10] PGE Exhibit 2501.
[11] PGE Exhibit 1401.

Q. Staff notes that PGE's total compensation costs, including contract labor expense, have remained relatively steady, while contract labor has decreased.[12] Does that support Staff's argument?

A. No. Staff is observing that PGE's total compensation actuals for 2023 remained relatively stable, but this analysis does not extend to budgets. As noted above, PGE has spent on average $24.5 million more than budget in each year that their analysis covers. PGE has demonstrated that a certain amount of dollars budgeted to straight-time labor ultimately get reallocated to contract labor; the contract labor adjustment reflects this reality to provide the most accurate and data-driven forecast possible.

Q. Staff repeats its claim that PGE is "artificially inflating" its contract labor costs through its contract labor adjustment.[13] How does PGE respond?

A. Staff has used this statement multiple times throughout this proceeding and has suggested that PGE's adjustment does not reflect historical costs. This is not true. PGE has shown this adjustment to be wholly based upon historical actuals of contract labor.[14] In fact, if Staff's proposed reversal of this adjustment were adopted, PGE's 2025 test year forecast for contract labor would be $23.6 million *below* the average 2021-2023 contract labor expense before any consideration of escalation. An adjustment cannot be considered to artificially inflate an expense when the underlying value remains $23.6 million dollars below historical data.

[12] Staff/3300, Yamada/6 at 12-13.
[13] Staff/3300, Yamada/9 at 1-12.
[14] PGE Exhibit 1401.

Q. What is the underlying basis for Staff's opposition to PGE's proposed contract labor adjustment?

A. The significant reduction in contract labor expenses, when considered in isolation, creates a substantial and glaring gap in PGE's total compensation budget. This approach appears to disregard the interconnected nature of our compensation structure. It is challenging to discern any rationale for such a disproportionate adjustment other than an attempt to minimize PGE's necessary total compensation recovery.

Q. If minimizing prudent recovery is the intent, how does PGE respond?

A. We urge the Commission to review the extensive evidence and analysis PGE has provided. We have demonstrated that PGE's contract labor adjustment is based on historical actual data, inclusive of a partial year of 2024 actuals. PGE has also demonstrated that the result is well below the average of the most recent three years of actual contract labor expense. Staff's arguments—that this adjustment is not based on historical actuals and that it artificially inflates contract labor expense—are erroneous. It is Staff's approach, not PGE's, that fails to accurately incorporate and reflect historical data.

Q. Staff rejects PGE's characterization of Staff's FTE reduction as "excessive and unfounded."[15] How does PGE respond?

A. Staff's proposed adjustment of approximately \$28.1 million for FTEs would, if adopted on its own, lower PGE's total labor expense forecast to include only a 1.1% annualized increase from 2023 to 2025. The additional inclusion of Staff's reduction related to the three-year wages and salaries model would push that total increase well below one percent. However, as noted above, the current projections per the state of Oregon are for annualized wage growth

[15] Staff/3300, Yamada/16 at 16-18.

of 4.5% over that same period. Meanwhile, Staff's three-year wages and salaries model demonstrates Staff's intent to include an inflation factor, albeit the All-Urban CPI rather than Oregon-specific wage inflation. PGE's initial total labor request represents known and measurable costs plus reasonable escalation, even before accounting for any new positions PGE has included in its request. In this context, Staff's FTE reduction <u>is</u> excessive, unfounded, and unsupportable and would harm PGE and our customers by calling for the reduction of labor and activities needed to support service for customers—below even Staff's own preferred inflation factor.

Q. Is AWEC's proposed reduction to PGE's labor excessive and unfounded for the same reasons?

A. Yes.

Q. AWEC claims that PGE's O&M labor is increasing "significantly higher" than 4.3%.[16] How does PGE respond?

A. PGE again points to a need for a holistic view of our total labor expense. In aggregate, PGE's labor increase comes in below the expected wage growth. By focusing on a portion of PGE's labor, AWEC examines neither our total labor expense nor what that expense is actually paying for. Individual O&M labor expense areas are discussed in detail in PGE Exhibits 300, 400, and 500 as well as their supporting workpapers, while aggregate amounts are detailed in PGE Exhibit 300 and its workpapers. AWEC has effectively chosen to ignore both views.

Q. Does PGE have any additional concerns related to Parties' proposed adjustments?

A. Yes. In Exhibit 3500 Staff clarified that their proposal to disallow four additional FTEs related to forestry positions was based upon their inclusion in UE 416 and Staff's belief that this

[16] AWEC/300, Mullins/28 at 13-19.

resulted in a double count.[17] While PGE disputes the factual basis for that adjustment in Exhibit 2700, we additionally note that any proposed reductions in staffing are already captured within Staff's FTE adjustment, making this proposal duplicative and therefore inappropriate.

Q. Does PGE continue to support its original forecast for total labor expense?

A. Yes. A forecast built upon known and measurable expenses, escalated with forecasts from an economic authority, is reasonable. Crucially, no party has raised any issue with prudence related to PGE's 2023 total labor expense, demonstrating that the underlying expenses are not in question. Concurrently, no party is proposing a decrease in staffing levels from that time. Essentially Parties' collective proposals imply that PGE should maintain 2023 levels of employees and pay them in 2023 dollars, but this is not how job markets work. Moreover, doing so would both harm PGE's attraction and retention of a qualified workforce and PGE's ability to continue offering the level of programs and service customers expect. Both Staff and AWEC propose reductions that would set PGE's total labor expense well below any reasonable escalation rate, affecting PGE's ability to stay competitive in the job market and perform the critical work our customers rely on. PGE recommends the Commission reject all of Staff's and AWEC's proposals related to total labor expense.

B. Incentives

Q. Please summarize Staff's rebuttal testimony and proposed adjustments to incentives.

A. Staff introduced a new proposal for incentive pay which would allow only 25% recovery of PGE's non-officer incentives and no recovery for PGE's stock incentive program. While this proposal appears to be an adoption of CUBs identical proposal, Staff supports their adjustment

[17] Staff/3500, Mondragon/8 at 12-19.

to non-officer incentive pay by supposing that PGE's Annual Cash Incentive (ACI) program meets the definition of a performance based rather than merit based program,[18] even while Staff notes PGE's statement that the stock incentive program supports the long-term interests of PGE.[19] Additionally, Staff proposes to reduce PGE's 2024 capitalized incentives by $1,872,052, on the premise that they are not already subject to pre-filing adjustment in accordance with Commission precedent and stipulations.[20]

Q. Have AWEC or CUB modified their incentives adjustments?

A. No. AWEC continues to support their proposed removal of stock as compensation, repeating their assertion that stock compensation is not appropriate for inclusion in a revenue requirement and that stock incentives align PGE employees with shareholder values. Similarly, AWEC maintains their original position on incentive overheads, asserting that PGE does not capitalize incentives and that PGE's pre-filing adjustment is not applied equally throughout revenue requirement. CUB simply restates their original proposals without response to PGE testimony on the matter.

Q. Please describe the pre-filing adjustments PGE made to its 2025 test year forecast for incentives.

A. Consistent with prior Commission decisions,[21] PGE's 2025 test year forecasts reflect a removal of 100% of officer cash and stock incentives, and 50% of all non-officer incentives including ACI, notable achievement awards, and stocks.

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[18] Staff/3300, Yamada/24 at 1-5.
[19] Staff/3300, Yamada/22 at 10-12.
[20] Staff/3300, Yamada/26 at 5-14.
[21] *In the Matter of Pacificorp Company Request for a General Rate Revision*, UE 374, Order No. 20-473 at 104 (Dec. 18, 2020); *In the Matter of Portland General Electric Company Request for a General Rate Revision*, UE 197, Order No. 09-020 at 12-13 (Jan. 22, 2009).

Q. How does PGE respond to Staff's characterization of ACI as "performance-based"?

A. In UE 374, the Commission distinguished between "performance-based" and "merit-based" incentives, noting that performance-based programs reflect benefits to shareholders including through financial performance, while merit-based programs reflected benefits to customers and shareholders alike.[22] Staff's supports their recharacterization of PGE's ACI program by noting that financial metrics are utilized in determining payouts. Although Staff does note that the majority of PGE's ACI program could meet the definition of merit-based, they suppose that any part of the program which they deem performance-based biases the entire incentive structure towards performance-based and thus is eligible for a 75% reduction in recovery.[23]

Q. Please describe PGE's ACI program.

A. Consistent with market practice, PGE's ACI program puts a certain amount of PGE employees' total compensation package at risk, which allows PGE to drive individual performance towards achieving collective goals. ACI pay is based on the company meeting certain metrics including the execution of corporate strategy, operations, financial health, and culture. Amounts paid in ACI are meant to allow PGE employees to meet the market median pay rate for the utility industry.

Q. Please describe the metrics used to determine ACI pay.

A. The metrics are as follows:

- Strategic, which measures how PGE has performed on its Wildly Important Goals (WIGs). These include increasing customer engagement, the advancement of grid readiness, and driving operational excellence.
- Financial, which focuses on the financial health of PGE.

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[22] UE 374, Order No. 20-473 at 104 (Dec. 18, 2020).
[23] Staff/3300, Yamada/24 at 1-5.

- Operations, which focuses on customer satisfaction, distribution reliability, and generation reliability.
- Culture, which focuses on employee engagement and diversity, equity, and inclusion.

Q. Do any of these metrics support PGE's customers?

A. Yes, all of them. PGE's strategic goals, or WIGs, deliver customer value through supporting a resilient and efficient utility, while also encouraging customers to engage with PGE as a partner in providing energy. The operational goals laid out by this plan again place customers as a focus, this time seeking their satisfaction with the service that PGE provides. Customers also greatly benefit from the reliable distribution and generation of electricity – many would likely consider this to be among their most important requirements of a utility. PGE's goals pertaining to culture support an engaged, diverse, and effective workforce best suited to support customer needs.

Q. Do the financial goals support PGE's customers?

A. Yes. A financially strong PGE can provide stability for PGE customers for years to come. Financial strength does not come to PGE through simply increasing customer rates or because PGE is allowed the opportunity to earn a regulated rate of return. Financial strength comes from effective decision making, implementing efficiencies, and the avoidance of imprudent expenses. Additionally, a financially strong PGE allows PGE to deploy capital in the most cost-effective way for customers – PGE receives a better value for equity it issues and preferable terms when issuing bonds that helps keep prices as low as possible for customers. This one goal—which is the crux of Staff's argument against the entire ACI program—clearly does not warrant a 75% reduction in recovery.

Q. What does Commission precedent say about programs such as ACI?

A. The Commission last visited this issue in UE 374, PacifiCorp's (PAC) 2021 general rate case. In that case, the Commission held that fifty percent recovery was appropriate for PAC's non-officer incentives program, having deemed that the "goals benefit both shareholders and ratepayers."[24] Before that, in PGE's rate case UE 197, the Commission granted fifty percent recovery of PGE's ACI program noting that allowing "50 percent of such costs into the revenue requirement is a fair approximation of the benefit to ratepayers."[25]

Q. In UE 374, did PAC's non-officer incentives program include metrics in support of financial health?

A. Yes, PAC's incentive program did include financial strength as a factor. Notably, the Commission recognized this, yet still decided that a 50/50 sharing principle should apply. The Commission's decision makes it clear that the inclusion of financial metrics as a part of a customer-benefitting incentive program does not make an entire incentive program a "performance-based" program and demonstrates that such an incentive program can remain eligible for fifty percent recovery.

Q. In UE 197, did PGE's ACI plan include metrics in support of financial health?

A. Yes, and again the Commission ruled that an incentive plan that included financial metrics was eligible for fifty percent recovery.

Q. How does PGE respond to Staff's testimony related to their proposal to remove all stock compensation from recovery?

A. Staff's proposed removal of all of PGE's recovery related to stock compensation is rooted in their belief that ownership in the company encourages employees to "act in the interest of

[24] UE 374, Order No. 20-473 at 104 (Dec. 18, 2020).
[25] UE 197, Order No. 09-020 at 12-13 (Jan. 22, 2009).

shareholders."[26] This is neither the intent, nor does PGE believe it is the outcome. The stock awards are granted to employees and senior leaders as a means of supporting retention, while also providing incentives for those employees and senior leaders to act in the long-term interest of PGE. A strong PGE is good for all stakeholders, whether they are a customer or shareholder. A strong PGE can provide customers safe, reliable, and secure energy at the lowest possible cost <u>and</u> provide a healthy return on investment to shareholders, while a weak PGE could struggle to provide either. The interconnected quality of PGE's long-term performance clearly warrants a cost-sharing between customers and shareholders, not a removal of this expense.

Additionally, in an attempt to justify their proposal to remove the amount PGE recovers for non-officer stock incentives, Staff claims in rebuttal testimony that PGE did not provide a sufficient response to a particular data request.[27] This is despite the fact that PGE responded to that data request on May 3[28]—over a month before Staff filed opening testimony in which Staff did not propose adjustments to PGE's stock incentives.

Q. How does PGE respond to Staff's 2024 capitalized incentives adjustment.

A. PGE notes that all capitalized incentives are adjusted, as described in PGE's Response to OPUC Data Request No. 265, to remove financial and officer incentives from rate base. This is performed in accordance with the outcome of UE 283, PGE's 2015 general rate case.[29]

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[26] Staff/3300, Yamada/22 at 13-15.
[27] Staff/3300, Yamada/22 at 7-10.
[28] PGE's Response to OPUC Data Request No. 264.
[29] *In the Matter of Portland General Electric Company Request for a General Rate Revision*, UE 283, Order No. 14-422, Appendix B at 2 (Dec. 4, 2014).

Q. Does PGE have any additional concerns related to Staff's testimony on incentives?

A. Yes. While at first glance it may appear as though Staff is merely joining CUB in their proposal to reduce ACI recovery, this is not the case. While Staff agrees with CUB, Staff uses a separate and distinct rationale, argument, and support for this adjustment. At this point in a general rate case, it is PGE's understanding that there should be a narrowing of issues being argued as they become fleshed out and potentially concessions are made on both sides. For Staff to propose a dramatic and likely precedent setting adjustment at this late stage in the docket is inappropriate as it gives neither side adequate time to fully support their positions and articulate their arguments.

Q. How does PGE respond to AWEC's testimony related to stock compensation?

A. Once again, shareholder interests and customer interests are not diametrically opposed and, contrary to AWEC's testimony, this is true even when it comes to revenue requirement. While it may be true that shareholders could benefit from a larger revenue requirement, customers do not necessarily benefit from a smaller revenue requirement. Customers benefit from a prudent revenue requirement, which is formed by this very process, because a prudent revenue requirement can provide for them the reliability, safety, and stability they need, while doing so with increasingly clean energy. These incentives, used to attract and retain senior leaders as a part of a market competitive compensation package, incentivize safety, reliability, security, customer satisfaction and engagement, efficiency, and the long-term financial security of PGE. They do this while promoting the retention of those highly qualified senior leaders, who have the experience and time invested at PGE to make the best possible long-term decisions, through three-year vesting cycles of restricted stock units (RSUs).

Through stock incentives, PGE transfers benefits to customers and shareholders alike because their interests are aligned, and therefore a fifty percent sharing of costs is appropriate.

Regarding AWECs assertion that stock does not represent an expenditure, PGE knows that equity has value. When raising capital PGE does not simply hand out shares – equity has a cost, and that cost must be recovered. Requiring these costs to be borne entirely by shareholders is inappropriate given that these employee incentives also benefit PGE's customers. The manner in which PGE accounts for these expenses is aligned with both ASC and FERC accounting standards and requirements.

Q. How does PGE respond to AWEC's testimony related to incentives overheads?

A. AWEC's continued support of this adjustment stems from their continued misunderstanding of PGE's accounting. Notably, they assert that the allocation credit does not reflect adjustments made to incentive overheads[30] and that PGE is not capitalizing incentives.[31] Neither statement is correct. In continuing to pursue this adjustment, AWEC is opportunistically seeking to inflate PGE's fifty percent prefiling adjustment to non-officer incentives.

Q. Are incentive overhead charges assessed to all other accounts and departments as AWEC asserts?

A. They are for departmental cost tracking purposes. However, for accounting purposes the incentive amounts allocated to departments are then netted against an equal and offsetting credit within accounting transfer departments. The purpose of this is so managers are able to review their fully loaded departmental budgets, while for accounting purposes, incentive amounts remain in their originating accounts.

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[30] AWEC/300 Mullins/37 at 7-9.
[31] *Id.* at 11-12.

Q. Does PGE capitalize incentives?

A. Yes, and PGE is unsure why AWEC believes otherwise. PGE's testimony that AWEC cites reads: "For amounts capitalized, PGE adheres to the stipulated agreement in UE 283, adopted by Commission Order No. 14-422, which specifies that PGE will not capitalize financial performance-based incentives."[32] We do capitalize a portion of non-financial performance-based incentives. The majority of the amounts in the credit that AWEC seeks to adjust are allocated to capital projects, which PGE seeks to recover properly and in accordance with the outcome of UE 283.[33]

Q. Did CUB respond to any of PGE's reply testimony arguments regarding their incentive proposal?

A. No. CUB made no attempt to respond to PGE's arguments.

Q. Has CUB offered any new arguments in support of their proposal?

A. No.

Q. Please summarize PGE's position on incentives, including stock compensation.

A. PGE maintains a market driven incentive program which targets a competitive total compensation package at the least possible expense. The goals and metrics associated with incentive pay balance customer and shareholder interests appropriately, and recovery is sought in accordance with Commission precedent and general rate case stipulations. The incentive proposals brought by Parties are excessive and unfounded, particularly when PGE has already removed 100% of officer incentives and 50% of all non-officer incentives from its request. PGE continues to recommend the Commission approve PGE's initial incentives request.

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[32] PGE/1400, Mersereau-Van Oostrum-Batzler/18 at 18-20.
[33] UE 283, Order No. 14-442 (Dec. 30, 2014).

C. Health and Dental Benefits

Q. Please describe Staff's testimony and updated proposal related to health and dental benefits.

A. Staff reduces their previous proposed adjustment from a reduction of $1.965 million to $0.485 million, citing PGE's documentation supporting an escalation factor of 8.5%.[34]

Q. How does PGE respond to Staff's revised adjustment?

A. PGE supports Staff's adoption of an 8.5% escalation factor and accepts the downward adjustment to $0.485 million.

[34] Staff/3800, Peterson/8.

III. IT Capital Additions

Q. Please summarize Staff's rebuttal testimony relating to IT Capital Additions.

A. Staff continue to focus their testimony on two blanket projects and two non-blanket projects. For the blanket projects, Network Fitness and CTO Desktop Fitness, Staff has reduced their previously recommended adjustment by approximately $200,000 to $3,341,209, which represents the three-year average of each blanket fund and escalation meant to represent inflationary effects. Staff's new argument for proposing a reduction to these blanket projects is that funds marked for these projects have been reduced in previous years. For the non-blanket projects, Zero Trust and EMS Upgrade, Staff reiterates their position that these projects should require an attestation and that rate base additions related to them be the lesser of the actual project costs upon completion or the originally forecasted investment for each project.

Q. How does PGE respond to Staff's testimony related to the two blanket projects?

A. Staff's testimony points to two particular downward adjustments made to these blanket projects in previous years to support their claims that they cannot predict what amounts will actually be placed into plant for these projects. These changes to projects occurred because of overlap between the goals of these blankets and other projects and the changing needs of the business and are a reflection of PGE's proactive efforts to control capital spending where possible. While PGE continues to object to Staff's methodology in favor of the original forecasted amounts, PGE further notes that simply escalating the three-year average does not create an inflation adjusted proposal; to reach that goal, each year that constitutes that three-year average must be escalated to 2025 dollars and then the average should be taken.

Correctly performing the calculation in this manner would create an inflation adjusted 2021 to 2023 three-year average of $7,868,160.

Q. How does PGE respond to Staff's testimony related to the two non-blanket projects, Zero Trust and EMS Upgrade?

A. PGE responds to these proposals, and all other attestation-related proposals, in Exhibit 2400.

Q. Please summarize PGE's stance on IT Capital Additions.

A. PGE requests the Commission reject Staff's proposal related to the blanket projects Network Fitness and CTO Desktop Fitness. Staff's concerns of underspending in these projects are unfounded and PGE stands by its original forecasts. As to attestation, PGE proposes and supports an alternative attestation process in Exhibit 2400.

IV. Corporate Support

A. Miscellaneous A&G

Q. Please summarize Staff's rebuttal testimony relating to A&G expense.

A. Staff continues to advance their adjustment proposed in their opening testimony, which was a downward adjustment of $1.78 million to FERC Account 921 (office supplies). Staff rejects PGE's rationale for the increased expense in this account, supposing that the amounts spent on operational change management for several of PGE's new software solutions did not justify the increase in expense because trainings are "usually a one-off event or non-incremental to normal operations."[35]

Q. Please summarize AWEC's rebuttal testimony relating to A&G expense.

A. AWEC's rebuttal testimony relating to A&G expense in aggregate was short and offered no additional arguments. Additionally, AWEC still supports their original proposals related to Directors & Officers (D&O) expense and stock compensation. AWEC seeks to institute a 90/10 shareholders-to-customers split in this expense, pointing to directors' fiduciary duty to shareholders as well as examples from other states.[36] AWEC's proposal relating to stock compensation of directors is to remove this expense entirely, again arguing that stock compensation incentivizes shareholder-centric decision making and that stock compensation does not represent a real expense.

Q. How does PGE respond to Staff's rebuttal testimony?

A. While it may be true that PGE will not incur the exact same training expenses beyond the 2025 test year, we do expect a higher level of training expenses in the future. PGE continues

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[35] Staff/3800, Peterson/6-7 at 16-2.
[36] AWEC/300, Mullins/34-35 at 15-2.

to explore IT solutions and plans to implement new systems and solutions, due in part to the rise of AI and other machine learning tools, which will lead to continued expense in this area. PGE expects that our workforce will soon utilize and interact with new AI and other machine learning based tools on a daily basis, and while these tools will introduce efficiencies and new capabilities across the organization, PGE expects to incur higher training costs related to these tools for the foreseeable future.

Q. How does PGE respond to AWEC's testimony on their overarching A&G proposal?

A. AWEC characterizes PGE's testimony in Exhibit 1400 as only a reiteration of PGE's position that the outcome of PGE's 2024 rate case informed our budget, and that as a signatory to the stipulations that settled that case it was inappropriate for AWEC to attempt to relitigate those issues. While this is certainly a part of PGE's testimony, it is not the entirety. In AWEC Exhibit 100, AWEC asserted that they were unable to truly analyze the A&G expense in this case and thus was unable to provide detailed analysis. In response to this claim, PGE's Exhibit 1400 directed AWEC to the workpapers that PGE originally filed with this case as sources of that information. AWEC's assertion that they did not have the opportunity to analyze PGE's A&G expense is belied by the fact that, on the very day this rate case was filed, AWEC had access to all of PGE's A&G expense, which could be viewed either in summary narrative form in testimony or in account level detail in workpapers. PGE also notes that AWEC had access to substantial volumes of information during the entirety of this case through the discovery process. PGE refutes AWEC's assertion that they did not have the opportunity to analyze PGE's A&G expense and strongly opposes the mischaracterization of PGE's reply testimony.

Q. Did AWEC respond to PGE's testimony pointing to the vast amounts of data PGE has shared?

A. No.

Q. Is it still PGE's position that this proposed adjustment is inappropriate?

A. Yes. Not only is the 2024 budget the result of negotiations and stipulations that AWEC participated in and signed onto, and therefore constitutes the proper basis for PGE's 2025 test year forecast, but the basis of AWEC's proposed reduction appears to be that they cannot discern what expenses are being forecasted, even though PGE has laid all that information out plainly and AWEC cannot point to any one case of imprudence. Put another way, PGE has given AWEC all data that they asked for as well as the 2021, 2022, and 2023 actual expenses, the 2024 budget, and the 2025 test year forecast, all in account level detail, and with all that information AWEC has not attempted to articulate imprudence at all. Nonetheless, AWEC continues to propose an excessive and unfounded adjustment that, in essence, constitutes a push to apply a historical test year.

Q. Are there any available updates to PGE's 2024 A&G expense?

A. Yes. So far in 2024, PGE is on track to spend approximately $9.1 million above budget on A&G expense.[37] This figure was developed through the combination of eight months of actuals (January through August) and originally budgeted amounts for the remainder of the year. The resulting amount is approximately $244.6 million in 2024 expense, whereas PGE originally forecasted a total amount of $221.7, net of pre-filing adjustments, for the 2025 year.

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[37] PGE Exhibit 2502.

Q. How does PGE respond to AWEC's testimony and continued support of their proposed D&O cost sharing scheme?

A. AWEC's rebuttal testimony dismisses PGE's previous arguments without addressing them, restates their original proposal, and for new arguments offers only that PGE's Board of Directors have a fiduciary responsibility to shareholders and that the State of Washington applies a sharing principle to D&O expense.[38] It is true that directors have a fiduciary responsibility to shareholders. It is also true that in the State of Washington there is a general policy of sharing the expenses between shareholders and customers, but to do so equally not with a 90/10 split.[39] PGE is required to have a board of directors to comply with SEC regulations. If federal regulation requires PGE to have an expense, and if that expense itself is not excessive, then it is PGE's stance that the expense is prudent and appropriately recoverable.

Q. Is PGE aware of or did AWEC point to any Oregon regulatory policy or precedent to support their position?

A. No.

Q. How do PGE's customers benefit from PGE's status as a publicly traded company?

A. PGE's customers benefit greatly from the access to capital that its publicly traded status allows. Shareholders provide the overnight capital that PGE uses to serve customers. Without shareholders, customers would likely have to shoulder more of the burden of investment. Additionally, being a publicly traded company requires PGE to follow SEC regulation, which includes extra layers of scrutiny—such as financial auditing, securities regulation, and public reporting of company performance and major events. In short, being a publicly traded

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[38] AWEC/300, Mullins/34 at 14-18.
[39] *WUTC v. Avista Corporation d/b/a/ Avista Utilities,* Docket UE-090134, Order No. 10 (Dec. 22, 2009).

company benefits PGE's customers through access to capital, accountability, and transparency.

Q. Does PGE's board make decisions that support customers?

A. Yes. PGE's board makes decisions that support PGE's resilience, reliability, and efficiency that collectively support customers. When PGE's board makes decisions that are in the long-term interest of PGE, customers benefit through the continued reliability and security of their energy.

Q. Does PGE's board make decisions that support shareholders?

A. Yes, though all actions taken at the board's direction that relate to PGE's regulated utility business are subject to the regulatory process. PGE's board cannot enforce recovery of imprudent expense, choose capital projects and place them into rate base without review, or seek to increase rates. PGE's board of directors sets plans for PGE's future to protect the long-term health of this company to the benefit of customers and shareholders alike, and does so only within the scope of the regulatory framework.

Q. Is AWEC's proposed D&O cost sharing scheme duplicative of their proposed overarching D&O adjustment?

A. Yes. AWEC denies this, but states "I did not separately remove the director's fees and expense when making that adjustment."[40] AWEC proposes an adjustment to PGE's A&G expense and then a further adjustment to one type of PGE's A&G expense. This is duplicative.

[40] AWEC/300, Mullins/35 at 6-7.

Q. Please summarize PGE's position on Staff and AWEC's proposals relating to A&G expense.

A. PGE recommends the Commission reject all of Staff's and AWEC's proposals for the 2025 test year forecast. Staff's proposal that seeks to remove amounts related to training and operational change at a time when technology is changing the way PGE serves our customers is short-sighted. AWEC's proposal to reduce A&G lacks basis as AWEC cannot point to a single imprudent expense despite being spoiled for data on this matter. AWEC's proposals related to D&O expense ignore the regulatory and legal requirements that PGE maintain a board of directors, overlook the benefits that arise from PGE's publicly traded status, and incorrectly assume that PGE's board of directors does not serve customers.

B. Insurance

Q. Please summarize Staff's rebuttal testimony relating to insurance.

A. Staff continues to support adjustments to both of PGE's insurance programs. For property insurance Staff recommends a downward reduction of $2,149,000, which is based on PGE's insurance cost for 2024 without an escalation factor for 2025. Staff notes that if an escalation factor was to be approved by the Commission, they would recommend an escalation of seven percent, which they base off the most recent MarketScout quarterly report. For casualty insurance Staff proposes a combined downward adjustment of $4,865,674. These adjustments are updated from opening testimony to reflect the most recent MarketScout quarterly report, as well as the updated 2024 premium for workers' compensation insurance. Staff supports their continued usage of MarketScout in the creation of these adjustments, supposing that third-party input was not included in PGE's 2025 test year forecast.[41] Additionally, Staff

[41] Staff/3400, Ball/7-8 at 16-5.

continues to propose a reduction of $482,020 related to policy holder credits PGE receives at times from our insurance providers.

Q. How does PGE respond to Staff's proposed reduction and further testimony related to property insurance?

A. Although Staff continues to propose their original adjustment, they do note that a seven percent escalation would be recommended if one was to be adopted at all. In light of this alternative proposal, and in the hope that compromise can be found, PGE updates the revenue requirement in this case to reflect the known and measurable 2024 expense plus seven percent escalation.

Q. How does PGE respond to Staff's proposed reduction and further testimony related to its casualty insurance program?

A. PGE recognizes and appreciates Staff's adjusted proposal related to workers' compensation and accepts the downward adjustment of $222,020 to this expense. Likewise, we accept Staff's proposed reduction of $230,316 to cyber liability coverage. However, PGE cannot accept Staff's proposed reduction of $4,413,338 to General and Auto Liability. This reduction, which is based on Staff's application of an escalation rate from MarketScout, is excessive and not reflective of the unique market pressures PGE and other utilities face.

Q. Does PGE agree with Staff's assertion that third-party input was not included in the 2025 test year forecast?

A. No. Staff is incorrect. PGE uses a third-party broker to develop our insurance programs and purchase the coverage needed at the best possible price. Additionally, Staff appears to be aware of this as Staff notes that PGE informed them of the third-party broker's input in Staff's testimony.[42]

Q. Is MarketScout an appropriate third-party source of escalation as Staff uses it?

A. No. In Exhibit 1400 PGE noted several flaws with this source: that the data does not relate to the utility industry; that it is a backwards examination as opposed to a forecast; and most importantly, that it only reflects trends over a single quarter of escalation data. Curiously, while Staff agreed with these flaws, Staff nonetheless insists that these limitations do not mean the data is "unreliable or not reflective of market trends."[43] PGE sees this quite differently. If data is not reflective of unique utility industry pressures, does not relate the year of the expense (i.e. 2025), and does not provide an entire calendar year forecast, it is unclear how it can be representative of utility's 2025 test year forecast, which represents an entire calendar year of expense.

Q. Has PGE received any additional input that would support an escalation greater than what Staff proposes?

A. Yes. Exhibit 2503C contains a presentation made to PGE by our third-party broker. In it, we can see two diverging forecasts for excess liability. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** This compares to Staff's proposed escalation rate of 4.7%.

Q. Who does wildfire coverage protect?

A. While the named policy holder is PGE, this policy protects all stakeholders from potential financial damages should an event occur. PGE relies on strong financial health to access

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[42] Staff/3400, Ball/3 at 14-18.
[43] Staff/3400, Ball/8 at 7-15.

affordable capital. Without protection PGE could face astronomical expenses and years of uncertainty during litigation related to damages potentially associated with PGE assets, which would weaken PGE's financial position and increase the cost of capital we face.

Q. What increase in excess liability did PGE face in 2024?

A. In 2024, excess liability rates represented an increase of 122% from 2023, going from approximately $7.0 million to $15.5 million in just one year. To contrast this, PGE notes that our forecasted premiums of $20.6 million represent only a 33% increase and suggest a rapid cooling of that market. However, if coverage becomes scarce PGE could very easily face expenses that greatly exceed that 33% escalation.

Q. Does MarketScout's report consider any of the unique pressures that utilities face in the excess liability market?

A. No. MarketScout measures changes in prices for insurance coverage, regardless of industry. The utility industry is facing historic changes in the way insurers view excess liability policies. Wildfire liability is even driving insurers to limit the amount of policies they will write, and some may even discontinue coverage entirely.[44] The principle of supply and demand very much applies to insurance, as it would any other good or service – when supply goes down and demand holds, prices will increase. To PGE's knowledge, no industry other than the utility industry has a risk profile that requires very large amounts of wildfire coverage at high risks, while also facing market constraints.

Q. Did Staff propose any other adjustments to PGE's insurance expense?

A. Yes. In opening testimony Staff proposed a downward adjustment of $219,473 related to D&O insurance, which was based on a three-year average of actual expense. In response to

[44] Utility Drive. "As wildfires losses mount…" Jan, 2024. https://www.utilitydive.com/news/wildfire-utility-grid-insurance-climate-pge-xcel-hawaiian-electric/703178/

additional analysis brought by PGE, Staff reduced that proposed adjustment to $78,295 in their rebuttal testimony.[45]

Q. How does PGE respond to Staff's reduced proposed adjustment?

A. PGE accepts the proposed reduction of $78,295 to D&O expense.

Q. On the matter of policy holder credits, how does PGE respond to Staff's testimony?

A. Staff acknowledges that these credits are neither guaranteed nor predictable,[46] and PGE opposes their inclusion in rates for these exact reasons. Additionally, PGE notes that, if it was beholden to a trailing three-year-average adjustment, it would in this rate case be paying for credits to property insurance companies that it no longer utilizes because of the transition to a largely post-loss insurance plan that does not pay out these types of credits. To set precedent for PGE to pay for credits that it may not receive would incentivize PGE to continue to utilize insurance companies that offer credits despite the availability of better options for customers. PGE notes that the transition to Everen's post-loss insurance saved customers more than $5 million dollars in the 2025 test year forecast alone, while on average PGE received only $482,020 in these credits over the last three years.

Q. Please summarize PGE's stance on insurance expense.

A. PGE finds Staff's proposed adjustments to workers' compensation, cyber liability, and D&O insurance acceptable. PGE would also accept Staff's alternative proposal to property insurance, resulting in a seven percent escalation from 2024 premiums. However, PGE finds that Staff's proposed reduction to General & Auto liability insurance is excessive, unfounded, and supported only by severely flawed data, and therefore PGE recommends the Commission reject that proposal entirely. Additionally, Staff's proposal to adjust PGE's test year forecast

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[45] Staff/3300, Yamada/28.
[46] Staff/3400, Ball/11 at 18-20.

by the average of recent, unguaranteed, and potentially volatile credits is inappropriate, especially in that it would not incentivize PGE to seek out the lowest cost insurance coverage.

C. Memberships

Q. Please summarize Staff's rebuttal testimony relating to memberships.

A. Staff continues to support their original proposed adjustment of $301,984, on the premise that certain of these memberships do not exclusively support customers. Additionally, Staff voices their belief that all of PGE's EEI dues are included in this request.

Q. Does PGE agree with Staff that these organizations do not exclusively benefit customers?

A. Yes, though all the membership dues that have been included for recovery in this rate case are necessary for PGE to fully participate in trade organizations and drive value for our utility business. In addition, these trade organizations allow PGE access to the best possible information, resources, and best practices that deliver great customer benefits, and the loss of access to this information would have deep effects on PGE's ability to efficiently and cost-effectively provide them with safe, reliable, and affordable energy that is increasingly clean. The value of pursuing membership in these organizations outweighs the savings customers would receive if PGE did not participate.

Q. Does PGE agree with Staff that the EEI invoice demonstrates that there was no lobbying adjustment performed to this expense?

A. No. The invoice to which Staff is referencing pertains to an expense of $790,644. This expense is demonstrated in line items "Regular Activities of Edison Electric Institute," "Industry Issues," and "Restoration, Operations, and Crisis Management." Each of those categories has a footnote denoting that amount of those dollars that are contributed to lobbying efforts (e.g. 13%, 20%, and 0% respectively).[47] Subtracting the amounts attributed to lobbying activities produces an amount of $676,238. Meanwhile, PGE's EEI amortization expense in the 2023 year totaled $671,238,[48] demonstrating that PGE's calculation of membership expense in fact seeks to recover slightly less than PGE's non-lobbying related EEI membership dues.

Q. Please summarize PGE's stance on Staff's proposed adjustment to memberships.

A. In PGE Exhibit 1400, PGE recognized that $47,347 of 2023 membership dues included in the calculation of a 2025 test year expense were erroneous, but that the remaining $254,637 are appropriately included as prudent expenses. In this testimony, PGE clarifies that $178,209 of Staff's proposed reduction is based upon their misunderstanding of PGE's 2023 EEI invoice. PGE therefore recommends the Commission reject Staff's proposed adjustment and accept PGE's modified memberships expense amount, as these memberships support our customers by providing PGE the best possible knowledge and resources to provide increasingly clean energy for our customers efficiently and effectively.

D. Revolver Fees, Margin Net Interest, & Broker Fees

Q. AWEC argues in rebuttal testimony that Commission Order 10-410 does not address revolver fees, margin net interest, or broker fees. Please summarize how revolver fees, margin net interest, and broker fees are proposed in UE 215 and ultimately addressed in Commission Order 10-410.

A. In PGE Exhibit 400 of Docket No. UE 215, PGE proposed to reclassify certain operating expense as net variable power costs (NVPC). These included broker fees, revolver fees, and

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[47] PGE's Response to OPUC Data Request No. 671, Attachment A.
[48] PGE's Response to OPUC Data Request No. 288, Attachment A.

margin net interest.[49] In response to PGE's testimony and recommendations, AWEC's predecessor, the Industrial Customers of Northwest Utilities (ICNU) argued that collateral costs (i.e., revolver fees and net margin interest) and broker fees "are more properly considered as part of the general rate revision."[50] Following this, PGE, Staff, CUB, and ICNU stipulated that "broker fees, revolving credit facility fees, and margin interest will all be removed from NVPC calculations and reclassified and included in O&M and A&O costs as appropriate."[51] Commission Order 10-410 adopted this stipulation. Following this order, PGE moved these costs for recovery in the general rate revision for base rates for the next eight proceedings, including this one.

Q. Did AWEC respond to PGE's correction of their claim that revolver fees are not considered in PGE's results of operations?[52]

A. No. The fact that these fees are reflected in PGE's results of operations, consistent with their treatment in general rate cases, was not addressed by AWEC in their rebuttal testimony.

Q. Clarify how revolver fees are accounted for versus how AWEC describes.

A. AWEC conflates revolver *fees* with *interest paid* on the use of the revolver, arguing the fees are included as short-term interest in the calculation of Allowance for Funds Used During Construction ("AFUDC"). This is not correct. Revolver fees are the fees paid to the bank to have access to revolving line of credit facility. These fees include revolver extension fees, annual fees, agent and legal fees. The revolving line of credit is used to ensure PGE has access to adequate short-term liquidity when all other possibilities are inaccessible.

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[49] Docket No. UE 215, PGE/400, Niman – Peschka – Hager/12-14.
[50] UE 215, ICNU/100, Falkenberg/2, at 11-12.
[51] *In the Matter of Portland General Electric Company Request for a General Rate Revision*, UE 215, Order 10-410, Appendix A, at 2 (October 20, 2010).
[52] PGE/1400, Mersereau – Van Oostrum – Batzler/43.

Q. How does PGE include short-term interest within its calculation of AFUDC?

A. PGE calculates monthly AFUDC amounts using the actual weighted average daily balance of short-term debt for the month and the actual total weighted average coupon rate for the month. These amounts come from PGE's treasury department and, as revolver *fees* are not debt and do not have a coupon rate, they are not included. PGE Exhibit 2504 provides an example of this calculation, which was for August 2023.

Q. Please address AWEC's statement that margin net interest balances are not being held in a liquidity constrained account.

A. AWEC is incorrect in their assertion that PGE is not maintaining the immediate liquidity of amounts for margin net interest balances. These margin net interest balances are associated with collateral or margin deposits that are related to wholesale power and fuel contracts for delivery and/or settlement in the future. These amounts are based on the difference in the contract price relative to the market price. PGE balances daily all of the amounts associated with the margin net interest transactions to ensure all funds are paid and collected as needed.

Margin net interest can be an expense or a revenue that PGE will either pay or receive from counterparties for these deposits for collateral for energy, capacity, transmission, and fuel purchase contracts, which are critical for PGE in securing economic and reliable power to meet customer load. These transactions' costs and revenues provide a lower cost to customers for amounts that would have otherwise cost customers more. Since the transactions benefit customers, the expenses in this case should be recovered from customers.

Q. Is AWEC correct that brokers fees are already included in FERC account 557 and should not be an adjustment to the revenue requirement?

A. No. While actual broker fees are recorded in FERC account 5570001, department 016, accounting work order 7000000545, because PGE has included a forecast for rate making in A&G since 2011, these costs are purposefully excluded from amounts forecast in Account 557. Therefore, PGE adds the amount for the brokers fees as an adjustment in the administrative and general expenses. PGE's response to AWEC Data Request No. 178 only shows 2023 actual amounts, which include broker fees booked to outside services following the above account string. However, PGE's request in the case using the same account string shows $0. Table 2 below shows this accounting geography.

Table 2
Broker Fees

Account	Dept Id	CE Source	Acct WO	Journal Category	2023 Actuals	2025 Forecast
5570001	016	Outside Services	7000000545	JGN25N	130,187	0
A&G	N/A	N/A	N/A	N/A	0	133,318

Q. Does Staff have a recommendation regarding AWEC's proposed adjustments for revolver fees, margin net interest, and broker fees?

A. Yes. Staff "recommends no adjustment for the issues identified by AWEC."[53]

Q. Does Staff address the treatment of the revolver fees, margin net interest, and broker fees per the adopted stipulation agreement in Order 10-410?

A. Yes. Staff notes that "the presence of a stipulated agreement, adopted by the Commission does not create a binding precedent. The agreement is a resolution of issues amongst the parties and adoption of such does not bind the Commission or represent a decision by the Commission

[53] Staff/2900, Pileggi/6, at 1.

on the future treatment of issues."[54] This characterization is consistent with PGE's own explanation in reply testimony, which noted that PGE first included these cost items in general rates "as a result of the stipulated agreement" amongst the parties, which "was formally adopted through Commission Order No.10-410."[55] Notably, this stipulation followed advocacy from Staff, CUB, and AWEC's predecessor entity, which all argued that such costs were not appropriate to be included in NVPC and should be recovered through a general rate case.

Q. What does Staff recommend for the treatment of revolver fees, margin net interest, and broker fees in this case?

A. Staff conditionally recommends that the Commission direct PGE to recover the revolver fees, margin net interest, and broker fees identified by AWEC through the modification of Schedule 125 to be effective beginning in 2026. Since this recommendation is made on rebuttal and intervenors do not have the opportunity to respond, Staff's recommendation is conditional on other parties and the Company not objecting.

Q. Does PGE support Staff's recommendations related to revolver fees, margin net interest, and broker fees?

A. PGE does not agree that revolver fees, margin net interest, and broker fees should be removed from this case and recovered as part of NVPC in Schedule 125. While PGE did recommend in UE 215 that these costs be included in NVPC, we no longer recommend that treatment for a few reasons. First, while largely associated with power operations, these costs are not recorded within power cost accounts and thus would require a corresponding annual adjustment to PGE's annual power cost adjustment mechanism. Second, these costs do not

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[54] Staff/2900, Pileggi/4 at 17-20.
[55] PGE/1400, Mersereau-Van Oostrum-Batzler/42.

tend to fluctuate significantly each year. Third, PGE's revolving line of credit is not solely intended for power operations. As such, PGE recommends that these expenses remain in the GRC. However, should the Commission determine they are more appropriately included within Schedule 125, PGE recommends that they remain within this case and be subsequently included and discussed within Schedule 125 upon PGE's next general rate review proceeding for alignment purposes.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
2501	2024 Labor Expense
2502	2024 A&G Expense
2503C	Third-Party Insurance Forecast
2504	August 2023 AFUDC

Aggregate Wages by CE w OT & Non-PGE	Dec - 2023	Dec - 2024 Budget	Dec - 2024 8+0	Dec - 2024 8+4	Dec - 2025
1101: Straight-Time Labor - Salary	204,563,478	224,597,894	144,168,041	219,529,980	225,578,268
1102: Straight-Time Labor - Union	62,330,916	74,077,957	43,779,554	68,431,959	80,360,968
1103: Straight-Time Labor - Hourly	17,694,093	21,561,793	11,488,375	18,999,398	22,372,111
1200: Other Union Labor		4,191,874		1,424,947	4,428,959
1201: Union High Time	54,702		15,706	15,706	
1202: Union Premium Pay	5,562,532	120,418	4,915,462	4,965,631	120,418
1401: Overtime - Hourly	1,378,342	962,428	1,218,626	1,564,475	1,083,051
1402: Overtime - Union	27,020,235	20,163,610	23,878,485	30,787,358	21,305,890
1501: Temporary Labor Straight Time	2,483,999	2,304,414	2,006,706	2,804,339	2,391,671
1502: Non-PGE Labor Straight Time	52,389,000	30,687,901	30,525,517	40,779,563	47,126,967
1601: Temporary Labor Overtime	149,335	2,287	136,590	136,590	2,378
1602: Non-PGE Labor Overtime	8,090,970	6,884,728	15,540,865	17,797,296	6,955,640
5104: Vacation OH	51,251,852	56,237,314	26,513,562	45,434,435	59,248,942
5501: Labor Allocation - ST Salary	(427,456)	(675,455)			(732,614)
5502: Labor Allocation-ST Hrly Union	105,529	157,989			167,076
5503: Labor Allocation-ST Hrly NonUn	(14,536)	(26,504)			(28,592)
5505: Labor Allocation-Union Premium	(327)				
5506: Labor Allocation - Hourly OT					
5507: Labor Allocation-Union HrlyOT	(5,959)	(191)			(193)
5509: Labor Allocation-ST Temporary	(5,606)	(8,129)			(8,454)
Total	**432,621,098**	**441,240,329**	**304,187,489**	**452,671,676**	**470,372,487**

	2023 Actuals	2024 Budget	2024 Jan-Aug Actuals	2024 Jan-Aug Actuals + Sep-Dec Budget	2025 Forecast
PGE Labor	$ 372,141,128	$ 403,667,701	$ 258,121,107	$ 394,094,817	$ 416,289,879
Contract Labor	$ 60,479,970	$ 37,572,629	$ 46,066,382	$ 58,576,860	$ 54,082,608
Total	$ 432,621,098	$ 441,240,329	$ 304,187,489	$ 452,671,676	$ 470,372,487

Account	2023 Actuals	2024 Jan-Aug actuals + Sep-Dec Budget	2025 Forecast
9200001: A&G-Wages-Allocable	$ 9,051,577.43	$ 22,223,882.51	$ 12,451,548.24
9200002: A&G-Wages&Salaries(Non-Alloc)	$ 40,443,957.05	$ 61,897,111.35	$ 49,148,282.50
9200004: A&G-NotableAchievementAwards	$ 53,539.24	$ 36,298.00	$ 11,681.99
9200005: A&G-Corporate Incentive Plan	$ 23,689,035.28	$ 16,304,003.10	$ 10,052,239.34
9200006: Officer Incentive & ACI Plans	$ 13,039,047.41	$ 14,341,684.07	$ 3,666,744.35
9200007: A&G-Stock Incentive Plan	$ 15,603,682.54	$ 16,052,092.30	$ 2,978,990.03
9200008: Thermal/Wind Incentive Plan	$ 2,774,565.52	$ 2,891,984.11	$ 1,209,786.48
9200009: A&G-Wages-EmpSupp/Labor Rltn	$ 1,879,648.83	$ 4,851,678.59	$ 3,047,792.56
9200010: A&G-Loss Prevention	$ 1,189,055.72	$ 649,661.90	$ 911,108.16
9200012: A&G - Miscellaneous Awards	$ 3,000.00	$ 1,000.00	$ -
9200013: Perf Incent Compen - Non-Alloc	$ (8,888.06)	$ 2,605,603.36	$ 4,054,052.11
9200015: A&G-Record&InfoMgt	$ 829,522.72	$ 1,232,609.88	$ 1,094,666.00
9210001: A&G-NonLabor Exp-Allocable	$ 3,849,256.63	$ 1,825,347.86	$ 4,866,886.36
9210002: A&G-NonLabor Exp-Nonalloc	$ 10,602,050.35	$ 8,114,213.06	$ 11,680,412.69
9210009: A&G NonLabor-EmpSup/Labor Rltn	$ 106,980.78	$ 221,314.94	$ 20,461.17
9210010: OfficeSupp&Exp-Loss Prevention	$ 55,114.20	$ 15,069.46	$ 118,056.38
9210011: OfficeSupp&Exp-A&GNonAllcToCS2	$ (508,096.21)	$ (511,642.45)	$ 19,887.85
9210014: OfficeSupp&Exp-AdminFeeFromPGE	$ 43,489.74	$ 11,648.54	$ -
9210015: OfficeSupp&Exp-Record&InfoMgmt	$ 124,847.17	$ 32,385.49	$ 27,717.61
9210019: Utilities-A&G Facilities	$ 2,302,731.86	$ 2,715,812.77	$ 2,404,695.66
9220001: AllocCredit - CorpGov	$ (8,648,417.28)	$ (30,475,857.76)	$ (10,571,151.16)
9220002: AllocCredit - Empl Support	$ (975,184.84)	$ -	$ (1,493,615.96)
9220003: AllocCredit - Corp Incentive	$ (11,628,815.12)	$ (16,246,577.19)	$ (4,725,336.49)
9220004: Corporate OH Expense	$ -	$ 9,457,796.67	$ -
9220005: Corp Incentive LL Expense	$ -	$ 6,552,699.82	$ -
9230001: Outside Services - NonAlloc	$ 18,154,420.42	$ 21,415,387.90	$ 14,513,242.86
9230002: Outside Services - Allocable	$ 1,171,709.05	$ 818,125.00	$ 663,877.29
9240001: Property Insurance Expense	$ 10,147,734.02	$ 4,870,061.78	$ 6,459,568.54
9250001: Injuries&Damages Expense	$ 2,274,860.51	$ 5,481,997.12	$ 2,678,841.89
9250002: Injury&Damages-Unallocated	$ 654.42	$ 735,000.00	$ -
9250003: Injury&Damages-Allocated	$ 10,888,115.62	$ 20,022,457.94	$ 26,250,967.39
9250004: AllocCredit - Injury&Damage	$ (7,258,644.01)	$ (25,106,198.76)	$ (15,663,480.62)

9250005: I&D LL Expense	$	-	$	11,405,147.07	$	-
9260001: BenefitExp-Pension Svc Cost	$	9,962,889.96	$	9,931,872.36	$	8,841,698.43
9260002: BenefitExp-PensionNonSvcCost	$	(6,580,750.00)	$	(6,083,365.28)	$	(4,896,774.53)
9260003: BenefitExp-PostRetireLifeUnion	$	57,470.00	$	36,345.00	$	64,174.96
9260004: Benefit Exp - Medical Union	$	14,929,866.54	$	14,297,680.89	$	16,429,698.38
9260005: Benefit Exp - Medical NonUnion	$	33,913,768.76	$	36,651,546.81	$	40,561,995.24
9260008: BenefitExp-HRA Union	$	935,000.00	$	1,894,000.00	$	1,836,997.55
9260009: BenefitExp-HRA Non Union	$	-	$	-	$	-
9260011: BenefitExp-STD Insurance	$	490,335.70	$	117,680.03	$	67,999.95
9260014: BenefitExp-EducationProgram	$	167,980.36	$	283,200.32	$	459,999.36
9260015: AllocCredit - Empl Benefits	$	(42,620,004.86)	$	(96,092,503.24)	$	(52,173,374.80)
9260016: BenefitExp-MiscEmployeeBenefit	$	1,208,538.54	$	1,843,050.08	$	2,203,137.11
9260018: BenefitExp-EmployeeWellness	$	183,080.99	$	156,487.24	$	158,440.87
9260019: BenefitExp-EmployeeAssistance	$	126,565.50	$	141,083.00	$	143,999.81
9260020: BenefitExp-AdminsterPrograms	$	1,083,824.47	$	1,537,579.00	$	811,966.75
9260021: BenefitExp-LongTermDisability	$	615,573.25	$	1,903,986.33	$	1,729,322.65
9260022: BenefitExp-Savings Plan	$	30,743,206.39	$	37,234,982.04	$	42,954,323.62
9260024: AllocCredit - PensSvcCost Co	$	(340,730.21)	$	(9,931,872.36)	$	(272,929.37)
9260026: AllocCredit - PensSvcCost PGE	$	(4,525,733.45)	$	-	$	(3,998,542.82)
9260027: AllocCredit - PensNonSvc	$	3,149,281.58	$	6,083,365.28	$	2,312,603.85
9260031: OtherPostEmplBene-ServiceCost	$	740,206.08	$	761,444.08	$	713,540.06
9260032: OtherPostEmployBene-NonSvcCost	$	(531,981.52)	$	831,037.56	$	850,129.88
9260036: AllocCredit - OPEB Service	$	(363,263.55)	$	(761,444.08)	$	(341,952.01)
9260037: AllocCredit - OPEB Non-Service	$	(441,892.01)	$	(701,754.56)	$	(411,289.39)
9260038: BenefitExp-NonSvcCost	$	-	$	-	$	-
9260039: OPEB NSC LL Expense	$	-	$	295,190.73	$	-
9260040: OPEB SC LL Expense	$	-	$	325,180.64	$	-
9260041: Pension SC LL Expense	$	-	$	4,239,121.91	$	-
9260043: NPPC NSC LL Expense	$	-	$	(2,603,205.04)	$	-
9260044: Emp. Benes LL Expense	$	-	$	40,694,444.24	$	-
9280001: Regulatory Commission Expense	$	1,991,810.90	$	2,177,220.21	$	807,954.93
9280002: RegCommExp-FERC Fees	$	11,532,206.86	$	13,865,994.93	$	1,198,900.44
9280003: RegCommExp-FERCSalesforResale	$	1,250,669.01	$	1,253,831.04	$	1,253,829.39
9280004: RegCommExp-RES Compliance	$	43,250.51	$	30,076.23	$	-

9290001: DuplicateChargesOffset-Credit	$	(3,277,090.96)	$	(3,538,526.13)	$	(3,350,768.80)
9302001: MiscGenExp-A&G Misc Expenses	$	7,261,038.16	$	7,708,283.70	$	8,155,028.85
9302002: MiscGenExp-Dir Pen & DDCP	$	173,870.83	$	151,182.08	$	56,999.93
9302003: MiscGenExp-Invol Severance Prg	$	1,323,669.94	$	1,565,409.00	$	-
9302004: MiscGenExp-Dir Fees & Exps	$	3,098,117.39	$	3,228,350.37	$	2,811,250.81
9302005: MiscGenExp-StkIncentiPlanDirec	$	1,304,755.56	$	531,645.41	$	688,749.12
9302006: Commercial Paper Fac Fees	$	-	$	262,083.33	$	146,493.31
9310001: Rents - General Facilities	$	3,900,472.99	$	831,784.94	$	4,033,069.09
9350001: Building Maint-A&G Facilities	$	3,992,366.45	$	4,262,474.15	$	3,231,253.50
9350002: HVAC Maint-A&G Facilities	$	528,538.47	$	806,309.76	$	907,921.08
9350003: Site Maint-A&G Facilities	$	211,127.81	$	342,809.44	$	139,214.31
Broker Fees:	$	130,187.62	$	223,731.00	$	133,318.08
Margin Net Interest:	$	1,220,696.00	$	1,220,696.00	$	1,220,696.00
N/A: N/A	$	-	$	-	$	14,169,660.30
Revolver Fees:	$	2,823,906.00	$	2,157,244.00	$	2,157,244.00
Grand Total	**$**	**219,663,377.05**	**$**	**244,607,530.87**	**$**	**221,683,903.07**

UE 435

Exhibit 2503 is CONFIDNETIAL pursuant to General Protective Order No. 23-132

UE 435

Exhibit 2504 has been retained in its native format

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 435

Customer Service and Transportation Electrification

PORTLAND GENERAL ELECTRIC COMPANY

Surrebuttal Testimony of

Allison Rowden
Dain Nestel
Elyssia Lawrence

October 1, 2024

Table of Contents

I. Introduction and Summary

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

A. My name is Allison Rowden. I am the Senior Manager of Customer Service and Billing at PGE. I am adopting the reply testimony of John McFarland and Elyssia Lawrence previously filed in this proceeding in PGE/1500. My qualifications appear at the end of this testimony.

My name is Dain Nestel. I am the Director of Sales at PGE. I am adopting the reply testimony of John McFarland and Elyssia Lawrence previously filed in this proceeding in PGE/1500. My qualifications appear at the end of this testimony.

My name is Elyssia Lawrence. I am the Senior Manager of Product Management for Transportation Electrification (TE) at PGE. My qualifications appear at the end of PGE/1500.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to address certain issues and proposed adjustments raised by the Staff (Staff) of the Oregon Public Utility Commission (OPUC or Commission) and the Alliance of Western Energy Consumers (AWEC) (collectively, Parties) for Customer Service O&M and Transportation Electrification (TE)-related capital expenditures.

Q. What do Parties propose regarding Customer Service and Accounts, Key Customer Managers, and Transportation Electrification?

A. Parties make the following adjustments:

1. Staff recommends a $2.0 million reduction and AWEC proposes a $2.6 million reduction to customer accounts. Staff recommends a $1.5 million reduction (a decrease of $0.5 million compared to Staff/1100)[1] and AWEC recommends a $5.3 million reduction to customer service.

[1] Staff/3800, Peterson/5 at 17-18.

2. AWEC recommends a $700 thousand reduction in labor O&M for the Key Customer Manager Department.
3. Staff proposes a reduction of $463 thousand for the TE Department and a reduction of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for the EV Field Operations Department.
4. Staff proposes the following permanent disallowances to PGE rate base:
    a. Disallowance of $352 thousand for the UM 1811 Electric Avenue and TriMet projects,
    b. Disallowance of $1.4 million for the Electric Island Heavy-Duty charging project,
    c. Disallowance of $177 thousand for the TE Database project, and
    d. Disallowance of $1.1 million for line extension allowances received by customers from 2019 to 2023 for transportation electrification upgrades.

Q. Please summarize PGE's response to these proposals.

A. PGE responds as follows to the issues listed above:

1. PGE Customer Accounts and Customer Service non-labor O&M is reasonable, justified, and supports needed activities for customer service and customer product offerings. The 2025 test year request is a decrease to the 2024 budget, which was discussed in Docket UE 416.[2] Key drivers from 2023 to 2025 are a Distributed Standby-Generation (DSG) amortization, an increase for the TE department primarily to support TE plans and program development, and in Brand Marketing to

[2] See *In the Matter of Portland General Electric, Request for a General Rate Revision,* Docket UE 416, Order No. 23-476, (Dec 18, 2023).

increase customer awareness and participation in energy management, which was approved in UE 416.[3]

2. Key Customer Management Department O&M is necessary to staff and support a team to address high-growth large industrial customers, the complexity of new construction projects and expansions, and the increasing complexity of their needs as industry decarbonization and system constraints require more innovative and complex solutions. AWEC's arguments are premised on a misunderstanding of department headcount, where AWEC failed to factor in the three positions.
3. Transportation Electrification O&M supports development of customer programs, TE plan and market research. PGE disagrees with Staff that all TE O&M must be in the TE Plan. The O&M to support TE is important in the development of TE offerings but is not a direct customer program cost.
4. The requested TE capital project-related rate base is prudent and benefits customers, and reflects prudent investment decisions made in an evolving market space with the best available information known at the time. Staff's concerns for each of these projects are addressed in Section IV.

[3] UE 416, Order No. 23-476, (Dec 18, 2023).

II. Customer Service and Customer Accounts O&M

Q. Please summarize PGE's request regarding Customer Service & Customer Accounts non-labor O&M.

A. PGE requests recovery of $26.2 million for non-labor O&M related to Customer Accounts and Customer Service; an overall decrease of $0.4 million compared to the 2024 budget built on amounts settled in UE 416, and a $7.9 million increase compared to 2023 actuals.

Q. What are the key drivers of the increase from 2023 to 2025?

A. A primary driver of the increase relative to 2023 is a $2.2 million increase for a DSG amortization in Customer Accounts, where the DSG amortization is related to expansion and upgrades to grow this valuable capacity resource at customer sites.[4] Other key drivers are escalations due to higher billing transactions and vendor costs, TE department non-labor O&M, and Brand Marketing department O&M. For 2025, PGE kept O&M items in these areas relatively flat to the prior rate case, with minimal increases to reflect higher costs associated with billing and billing transactions and the movement of some expenses from supplemental schedules into base rates in 2024 and 2025.

Q. What is the rationale for Staff's proposed reductions to Customer Accounts and Customer Service non-labor O&M?

A. Staff proposes a combined $3.5 million reduction to non-labor O&M to bring the 2025 forecast down to the 3-year average from 2021 to 2023. Staff Exhibit 3800 reiterates Staff's position that a historical 3-year average is "reasonable"[5] Staff does not provide any further justification for the reduction, aside from pointing to Staff's position opposing additional

[4] Further discussion of the Diesel Particulate Filter project and the benefits of DSG can be found in PGE/1700, Powell-Clark/21 and PGE/2800, Powell-Clark/6-7.
[5] Staff/3800 Peterson/2 at 7-8 and Staff/3800 Peterson/7 at 1-2.

DSG, which Staff clarifies is not the basis of the Customer Accounts proposed adjustment.[6] Staff states "[t]he referencing of the inclusion of expenses to DSG amortization is further evidence that the amounts included in this account are inflated and not justified."[7]

Q. Did Staff reply to PGE's points on the cause for the increase in O&M relative to 2023 and PGE's point that non-labor O&M is a decrease to 2024 budget?

A. No, Staff did not. However, Staff did reduce the proposed adjustment by $0.5 million.

Q. Why did Staff reduce the proposed adjustment to Customer Service?

A. Staff reduces their adjustment given PGE's reply testimony explaining the shift in timing for budget from 2023 to 2024.

Q. Aside from timing adjustments to budget does Staff indicate other valid reasons to deviate from a three-year historical average to set the Test Year?

A. Staff provides three other examples of when deviating from a historical average is warranted. As explained by Staff these are "1. Errors or Omissions, 2. Known transfers or delays in expenditure (as adjusting for in FERC Account 908), and 3. Additional expenses that would be ongoing and cannot be covered by the base level of budgeted expenditures." [8]

Q. How does PGE's 2025 test year request fit into the reasons that justify departure from a three-year historical average?

A. The explanation of the drivers for the changes from 2023 to 2024 and then to the 2025 test year fit squarely within Staff's reasons cited above. The changes in FERC Account 903 are related to billing and customer support, which is on-going need to support a growing customer base, and a known change related to the DSG amortization. Similarly FERC Account 908

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[6] PGE Exhibit 2601. Staff's response to PGE Data Request No. 26.
[7] *Ibid*.
[8] PGE Exhibit 2602. Staff's response to PGE Data Request No. 27.

changes are related to on-going expenses discussed in UE 416 for Brand Marketing and customer program departments that develop and expand offerings for customers, particularly to meet the evolving energy landscape.

Q. How does AWEC support its recommended reductions to non-labor O&M and respond to PGE's justification for the 2025 proposed non-labor O&M?

A. AWEC cites higher test year non-labor O&M relative to historical actuals as the basis for the reductions and found that "much of the variance is unexplained and unjustified."[9] However, like Staff, AWEC does not identify specific items they feel are unsupported and unjustified, and instead proposes the adjustments based on an escalated historical level. Nor does AWEC indicate where PGE's explanations provided in reply testimony and data request responses fall short.

Q. Does AWEC provide any new critique of Customer Service/Accounts or the reasonableness of the 2025 Test Year amount ask in this case?

A. No. AWEC still has not inquired through data requests or provided additional narrative in their rebuttal testimony to counter the prudence of our current Customer Accounts and Customer Service non-labor spend or the reasonableness of our 2025 Test Year expense. They simply state that Customer Accounts and Customer Service non-labor O&M should be held at an escalated three-year average.[10]

Q. On a historical basis, how did PGE explain the cause for the increase from 2023 to 2025?

A. PGE explained the increase from 2023 to 2025 in PGE Exhibit 1500[11] and in response to data requests.[12] AWEC neglects to acknowledge or respond to other cost drivers and misrepresents

[9] AWEC/300 Mullins/22 at 8-10.
[10] *Id.*
[11] PGE/1500 at 11-12.
[12] PGE's response to OPUC DR 377, PGE's response to OPUC DR 190 addressed a question on billing expense.

PGE's justification as being "only" cost escalations, which is not true. PGE/1500 provided the major cost drivers and, after the "normal cost escalations," explained that billing costs are due to additional customer payment processing fees and billing-related expenses, which increase with customer growth and increased billing transactions as well as vendor cost escalations.

Q. What is your request of the Commission?

A. We request the Commission approve PGE's requested 2025 Customer Accounts and Customer Service non-labor O&M and reject the adjustments proposed by Staff and AWEC.

III. Key Customer Manager Department Labor O&M

Q. What does AWEC propose regarding the Key Customer Manager department O&M?

A. AWEC recommends a $700 thousand reduction, which is labor and redundant of other labor reductions proposed by AWEC.

Q. How did AWEC respond to PGE's point that the KCM department labor costs were higher due to three FTE positions in the KCM team added in 2024 and transferring from another department (budget neutral) in 2025?

A. AWEC did not address the points made in PGE reply testimony (PGE/1500), which justified the new positions supporting the complexity of construction projects, large industrial load growth, and complexity of large customer solutions and offerings.[13] AWEC also did not address or adjust the amount of the recommended reduction to reflect that the KCM reduction double-counts labor reduction with AWEC's overall proposed labor reduction and that one of the positions resulting in higher department labor O&M budget increase is offset by a reduction in other departments, as that position is an internal—rather than a net new—position.

Q. What do you request of the Commission?

A. We request the Commission reject AWEC's recommended reduction of $700 thousand in labor O&M for the Key Customer Management team, recognizing three additional employees are needed to support the evolving complexity of large customer projects and offerings. Because one of the positions is a budget-neutral shift, offset by labor O&M reduction in other departments, and AWEC's labor reduction recommendation is duplicative of AWEC's overall labor reduction recommendation, the reduction request is inappropriate.

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[13] PGE/1500, McFarland-Lawrence/14-17.

IV. TE-Related O&M and TE-Investments

A. UM 1811 Electric Avenue and TriMet Projects

Q. Please summarize Staff's recommendation for UM 1811 projects.

A. Staff recommends a rate base disallowance of $353 thousand for the portion of UM 1811 projects Staff believes exceeded the overnight capital cap allowed in UM 1811. PGE and Staff have a fundamentally different perspective on which costs are subject to the cap. In response to PGE's reply testimony, Staff did reduce the amount recommended for disallowance by the AFUDC amount of $15 thousand; this reduction is reflected in Staff's proposed disallowance amount of $353 thousand above.

Q. How does Staff respond to PGE's position that overhead and allocations are indirect costs and should therefore be excluded from the overnight capital cost cap?

A. Staff agreed with PGE that AFUDC is not subject to the cap. Staff disagreed with PGE that overhead costs are indirect costs and would therefore not be subject to the cap. Staff's arguments are:

1. PGE's categorization of overheads as indirect costs is "at odds" with the definition provided in Order No 19-385 (Appendix A, paragraph 10).[14] Staff states that the specific costs in paragraph 10 are "derived from the project cost" whereas "[o]verhead and allocated costs are not derived from the project's costs[,]" but when they are capitalized they then become part of the project cost.[15]
2. Staff takes issue with PGE's use of the word "incurred" interchangeably with direct, and implies the overhead costs exist and are in rate base <u>as a result of</u> the Electric Avenue

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[14] Staff/3200, Shierman/5 at 8 indicates Order No. 19-384 in Docket WJ 35, which PGE assumes Staff meant to refer to Order No. 19-385 in Docket UM 1811.
[15] Staff/3200, Shierman/5 at 13-15.

project. In this argument, Staff seems to misunderstand or mischaracterize how overhead capital cost allocation operates.

3. Staff disagrees that overhead allocated costs would have been "difficult to calculate" at the time of the UM 1811 Order No. 19-385.

Q. Please address Staff's position that classifying overhead costs as indirect costs is at odds with the definition provided in Order No. 19-385.

A. Overhead costs are indirect costs that are difficult to calculate at early project stages. Moreover, these overhead costs were not contemplated in the cost estimates shown in UM 1811 stakeholder workshops and settlement/stipulation conversations. Commission Order No. 19-385 indicates the costs listed in paragraph 10 are a partial list and examples of indirect costs. The "such as" PGE takes to mean examples of such costs, but not to be a comprehensive list. The phrase "indirect costs" immediately signals to PGE that overheads are considered within indirect costs. PGE project costs and final project costs were spent consistent with the project cost estimates used to inform the cost caps where overhead costs are indirect and not subject to the cap.

Q. How do you respond that indirect costs (i.e., those not subject to cost cap) are derived from the capital project, not allocated to the capital project?

A. Staff is attempting to find a meaningful distinction where one does not exist.

Q. Please respond to Staff's statement that if (direct or overhead) costs were not incurred in the construction of Electric Avenue, then PGE would not be able to capitalize these overhead costs to rate base.

A. It is unclear in Staff's statement whether the first set of costs incurred in the construction of Electric Avenue is meant to be the direct project costs or the overheads. Nonetheless, the statement is incorrect in both cases. Overhead costs exist whether or not a particular project is undertaken. Overhead costs are allocated across the entire capital portfolio during the year, capitalized, and then put into rate base once those projects are in-service. If the Electric Avenue project had not existed, the overhead costs would still have existed, would have been allocated to other projects, and would have been put into rate base.

Q. What support does Staff offer that overheads and allocations are not difficult to calculate at the ideation phase of a project at the time of Commission Order No. 19-385?

A. Staff does not offer evidence or clear reasons. Staff gives an example of a future authorized rate of return or other future costs determined in a rate case as "particularly unpredictable" to contrast with what Staff says is a relatively "simple near-term estimation" for overheads; however, Staff provides no other explanation on why overheads are "simple."

Q. What is PGE's perspective on the difficulty of calculating overhead costs for a project?

A. Overhead costs and how they are allocated to specific projects are indeed difficult to estimate in early project stages, as the total amount of overhead costs is set at a portfolio level and the allocation to individual projects is subject to multiple factors, all of which are beyond the control of an individual project manager. In part because overhead allocations are determined by many factors and allocated by accounting methodology, it is PGE's practice to hold project managers and individual projects responsible for projects on an incurred basis, as those are the direct project costs (such as vendor contract costs) that a project manager can control.

Q. What do you request of the Commission for the UM 1811 projects?

A. PGE requests the Commission approve cost recovery of the UM 1811 projects and deny Staff's proposed $353 thousand permanent rate base disallowance.

B. Electric Island

Q. What does Staff propose regarding the Electric Island project?

A. Staff recommends permanent rate base disallowance of $1.4 million.

Q. Please provide relevant background on Electric Island, Schedule 53, and why PGE is seeking cost recovery of Electric Island in this General Rate Review proceeding.

A. Electric Island is a first-of-its-kind, innovative medium-and heavy-duty charging project developed in partnership with a non-residential customer. PGE initially proceeded with the project anticipating additional legislative and regulatory authority to engage in such projects, but that authority did not materialize within the expected timeline. PGE sought to remedy the situation through the initial filing for Schedule 53 on February 10, 2021, requesting a tariff effective date of March 15, 2021, before Electric Island's in-service date.[16] At the public meeting on March 9, 2021, the Commission adopted Staff's recommendations to 1) suspend Advice No. 21-03 for further investigation (Schedule 53) and 2) address Electric Island cost recovery through PGE's General Rate Case proceeding [17] (rather than under Schedule 53). PGE has sought cost recovery of Electric Island in Docket No. UE 394, UE 416 and now in UE 435; Electric Island was included in black box settlements in both UE 394 and UE 416.

Q. Staff states that Electric Island spending was excessive. Please respond.

A. The total cost of Electric Island, including PGE's portion and technical assistance and planned future enhancement, is within the $5 million per site limit set by Schedule 53. Staff's recommendation to disallow $1.4 million, and their claim that the project is imprudent and

[16] Advice No. 21-03 NEW Schedule 53, Nonresidential Heavy-Duty Electric Vehicle Charging Program, February 10, 2021. https://apps.puc.state.or.us/edockets/docket.asp?DocketID=22751

[17] The first General Rate Case filed by PGE subsequent to the Commission Order was UE 394.

excessive, are unwarranted considering that Staff previously recommended Schedule 53 for approval with the same cost per site threshold.

While separate approval in a General Rate Case proceeding is required for Electric Island, the project's scale aligns with Schedule 53 guidelines. Electric Island was a particularly unique opportunity to partner and install a very innovative heavy-duty charging project and to make that project a public charging site for all of PGE customers to access.

Q. Staff states that PGE's participation in the project was "unnecessary." Please respond.

A. Staff asserts that PGE's investment did not produce any incremental benefit, as the customer would have made the charging station investment regardless. Staff's assertion is speculative and does not recognize that PGE customers and PGE staff receive much greater access to the site and project due to PGE's direct investment and partnership in this project. The customer benefits from access to the site are enumerated in PGE/1500.[18]

Q. Staff indicates there may be "possible" benefits to customers. Please respond.

A. Staff acknowledges the potential for customer benefits, as described by PGE, but limits this acknowledgment to later phases. Staff does not address the benefits of the cumulative 1 MW currently at the site, nor the customers who use the site and get direct benefits beyond the learnings and testing capabilities. Staff does not address the overall unique and cutting-edge nature of the project and PGE's ability to participate with a customer who is at the forefront of this market space. Rather, Staff looks at it as a negative and presumes the customer would have made the investment. However, Staff offers no support for a purely speculative argument.

[18] PGE/1500, McFarland-Lawrence/34-38.

Q. What do you request of the Commission?

A. We request the Commission allow cost recovery of the Electric Island project and deny Staff's recommended permanent disallowance.

C. TE Database

Q. What is Staff's proposal regarding PGE's TE database integration project?

A. Staff recommends permanent disallowance of $177 thousand of the TE database project cost and argues that PGE could collect and analyze TE-related data without having made this investment.

Q. Is Staff correct in saying that PGE already had a corporate database that can house TE data, and had PGE's TE data been integrated into that database?

A. PGE already had a corporate database capable of housing TE data; however, the interfaces necessary to ingest TE data into the database had not been created. That is what the 2023 database project accomplished—combining data from multiple sources within the corporate database and allowing PGE to more efficiently, thoroughly, quickly and easily report on key performance metrics across all commercial TE programs, as required by the Division 87 TE rules and the annual TE Plan Report.

Q. Could PGE produce TE data and reports without consolidating its TE data into the corporate database, as Staff suggests?

A. Laboriously, yes. PGE could use disparate sources of TE information, cross-reference them, and manually develop reports. However, this approach is labor- and time-intensive, especially as the amount, sources, and complexity of data multiply with the expansion of TE and TE-related programs. In addition to the meter data and session data Staff references in testimony, PGE's charging data includes a third type, charger asset data, which is critical for reporting and cannot be provided by anyone other than the customer. Session data is not controlled by PGE and can be defined and delivered in many different formats by EV software vendors, adding to reporting complexity absent a TE database to integrate the data sources. Given that we anticipate many years of TE-related activity ahead and need to better track and understand this load, an inefficient and outdated manual approach to data management and analysis would ultimately not serve customers, the Commission, or the Company well.

Q. Is Staff correct that PGE could use CSV files and/or free software like Python or R to meet Division 87 reporting requirements?

A. CSV files do not provide all the information needed for Division 87 reporting, nor are they an efficient way to manage large data. As an example, the CSV files do not provide information regarding which PGE program the charger is enrolled in (that information is not tracked by the customer's charging vendor). Relying solely on CSV files, PGE would not be able to report on any of the Division 87 reporting requirements that require a breakdown by program enrollment, use case, and location of the charger within an underserved community. To fulfill these reporting requirements, PGE must keep an internal database that associates the serial number of each charger to the program it's enrolled in, the area it is located in, and what type of use case is associated with the charger. While PGE does use free software tools, like Python and R, to automate processing of EV software vendor files into our enterprise database, these tools do not replace the need for data to reside in a database with integration of the disparate data sources.

Q. How has PGE's TE data management and processing evolved?

A. Before 2021, all TE program-enabled ports were owned by PGE, so PGE could report on those ports by requesting data from the vendor or accessing the vendor dashboard and downloading data. In 2021 and 2022, customers started installing chargers through new programs like Business EV Charging Rebates, Drive Change Fund, and Fleet Partner. Initially, each program created its own spreadsheet to track chargers installed through the program. However, PGE quickly realized two things: 1) the charger attributes were inconsistent across programs, making reporting difficult; and 2) there was no process to retrieve charging session data from vendors because PGE cannot access the vendor dashboard for customer-owned chargers. To address this, PGE developed the TE database integration project.

Q. Please summarize the benefits achieved through the TE database project.

A. The TE database project created the necessary interfaces for PGE's planning and TE teams to collect TE data, ingest it into the PGE corporate database, and format it so that it can readily be used for analytical and reporting purposes. Additional benefits include but are not limited to improved forecasting by including actual usage in the model, the ability to improve key performance indicators for customer programs through granular analytics, and strategic growth planning of grid infrastructure.

Q. Was the TE database project in the Budget approved in the 2023-2025 TE Plan?

A. Yes, the TE database project is included in the funding for capital expenditures under Portfolio Support in the TE Budget for 2023 in PGE's Final 2023-2025 TE Plan.[19] Neither Staff nor stakeholders questioned this capital allocation before the Commission approved the TE Budget with acceptance of the TE Plan, as provided for under the Division 87 TE Rules.

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[19] PGE Final 2023-2025 TE Plan, Table 33, Detail on Program Operating and Capital Expenditures

Q. Has Staff repeatedly emphasized the importance of strong data collection, analysis, and reporting in the fulfillment of PGE's responsibility to support TE?

A. Yes. In its report to the Commission recommending acceptance of PGE's TE Plan and approval of the TE Budget, and on many previous occasions, Staff expressed disappointment at what it termed our limited empirical understanding of our own EV market, despite possessing more real-world charging data and other market information than any other utility in Oregon. Staff noted that the collection of data was an important part of the basis for approving PGE's TE pilots, and that "Staff sees stronger analysis of this data important [sic] for future use in rate design, EV program development, resource planning, and distribution planning." [20] Staff went on to state that "[a]n important part of the policy justification of electric companies' TE activities is the public good from disseminating this TE data."[21] Commissioners reinforced this view in comments offered from the bench during the October 17, 2023 Public Meeting to accept the TE Plan.[22] Our TE database project was and is directly responsive to Staff's exhortation that we improve our TE data analysis capabilities, so we find their opposition to funding the project confusing.

Q. What do you request of the Commission regarding the TE database project?

A. We ask the Commission to reject Staff's recommendation to disallow the TE database project from rate base. Integration of TE data from multiple sources into a database facilitates effective operations necessary for planning, analysis, and reporting, serving the interests of PGE customers and the Commission as well as the Company now and in the future.

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[20] *In the Matter of Portland General Electric Company 2019 Transportation Electrification Plan*, Docket UM 2033, OPUC Order No. 23-380 at Appendix A and 17 (Oct. 20, 2023).

[21] Ibid.

[22] OPUC Regular Public Meeting, October 17, 2023. See Commissioner Tawney's comments beginning at approximately minute 18, available online at https://oregonpuc.granicus.com/player/clip/1232?view_id=2&redirect=true

D. TE-Related O&M in TE Department and EV Field Operations

Q. What does Staff propose regarding TE O&M?

A. Staff recommends a $463 thousand reduction for the TE Department and a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** reduction for the EV Field Operations Department. The functions of these departments are described in PGE/1500.

Q. Are these the only TE-related O&M reductions Staff proposes?

A. No. Staff's opening testimony proposed a reduction of $920 thousand to the TE Department budget and a reduction of $993 thousand to the EV Field Operations budget. In rebuttal testimony, Staff agreed with PGE that Staff's recommended reductions to TE operating expenses were duplicative of Staff's overall recommended reductions to labor costs, and has now removed the labor portion of Staff's TE operating expense adjustment. Staff reaffirmed that its arguments in favor of the reduction should be applied to the overall reduction recommended by Staff Witness Stephanie Yamada. Staff has also concluded its recommended reduction to PGE's EV Field Operations Department should itself be reduced, because some of the department's budget was contained in the TE Budget within the current, 2023-2025, TE Plan.

Q. What is the basis for Staff's recommendations regarding TE O&M?

A. Staff's position is that no amount of TE-related O&M above the amounts in the TE Plan as approved by the Commission in Order No. 23-380 can be considered prudent or allowable for cost recovery in this proceeding, and as a general principle that no TE-related expenditures presented in a general rate case can be judged prudent without first having been approved in a TE Plan. Staff applies this principle to both the TE Department and the TE Field Operations

Department. Order No. 23-380 accepted PGE's current TE Plan and approved the TE Budget included in the plan, as required under the Division 87 TE rules.

Q. Is the TE Plan a prudency review, rate-setting, or cost recovery mechanism?

A. No. In OAR 860-087-0020(2)(a) the Division 87 TE rules specifically state that Commission acceptance of an electric company's TE Plan does not constitute a determination on the prudence of the individual actions discussed in the TE Plan, and Docket UM 2033, the proceeding established to manage PGE's TE Planning efforts, is not a rate-setting or cost recovery proceeding.

Q. Does the Commission-adopted guidance to utilities for implementation of the Division 87 TE rules, contained in Order No. 22-314, specify the scope of expenditures to be included in the TE Budget within the TE Plan?

A. In part. The guidance developed by Staff and adopted by the Commission with Order No. 22-314 is focused on performance metrics and other aspects of TE Plan content. It addresses elements of reporting relating to expenditures, but primarily with regards to accounting for expenditures from House Bill 2165 TE Monthly Meter Charge revenues and from Clean Fuels Program funds, each of which have certain limitations and requirements for how they are to be spent. The Order No. 22-314 does specifically address the TE Budget in one respect, in that it acknowledges utilities are not required to include expenditures for the electrification of their own fleets in their TE Budget, although they have that option. With this reference the guidance effectively acknowledges that the utility may make TE-related expenditures that are not included in the TE Budget.

Q. Do the Division 87 TE rules require that "all expenditures to support transportation electrification" be included in the TE Budget in the TE Plan?

A. No. That is an incomplete reading of the rule. The full citation in OAR 860-087-0020(3)(g)(A) states that the TE Plan must include the company's TE Budget, and that the budget must include annual budgets for the three calendar years encompassed in the plan, including "[a] forecast of all expenditures to support transportation electrification *grouped by program and/or infrastructure measure*, and further divided into (i) Capital expenditures; and (ii) Expenses, separating administrative costs, *O&M on investments*, incentives paid to program participants, and any other unique category as relevant."[23] The full context of the citation makes it clear the TE Plan and TE Budget are intended to summarize and report on programmatic activities and infrastructure investments. This is consistent with the definition of "transportation electrification" found within ORS 757.357, which is also focused on programs and infrastructure measures supporting adoption and service of vehicles.[24] Neither the rule nor the statute address utility base business activities that support overall development and administration of the TE Plan or support TE-related work and investments that cannot appropriately be attributed to specific activities, programs or infrastructure measures, as part of the plan itself. These base business activities are properly considered in a general rate case.

Q. Is Staff effectively attempting to use the TE Plan as a pre-prudency review mechanism?

A. Yes. Despite the explicit statement in the Division 87 rules that acceptance of the TE Plan does not constitute a prudency determination, Staff's arguments regarding our TE O&M expenditures effectively mean that, while inclusion of an expenditure in the TE Plan and its

[23] OAR 860-087-0020(3)(g)(A) (emphases added).
[24] ORS 757.357.

TE Budget may not guarantee it will be considered prudent, by Staff's interpretation it cannot be considered prudent if it was *not* included in the plan. Staff explicitly states in their testimony that "[t]he place for PGE to make the case for planning cost expenditures . . . is UM 2033, not this proceeding."[25] This ignores that UM 2033 is not a cost recovery proceeding and the TE Plan is neither a rate-setting mechanism nor the appropriate place to document expenditures required to operate the business, such as fleet costs.

Q. Please explain how the Company's interpretation of the TE Budget requirements is consistent with the Division 87 TE rule's objectives.

A. Focusing the TE Plan and Budget on the operation of programs and infrastructure measures supports the TE Plan objective stated in the Division 87 rules, which is to "[i]ntegrate the electric company's transportation electrification *actions* into one document. The Plan shall include, but is not limited to, the electric company's portfolio of near-term and long-term transportation electrification actions, including applications for program(s) and infrastructure measure(s), planning and expenditure of the Monthly Meter Charge, and other transportation electrification actions such as Clean Fuels programs."[26] This focus on actions, programs, and infrastructure measures allows Staff and stakeholders to review and understand the full portfolio of programmatic activities and expenditures the Company is undertaking to support TE. However, some of our TE-related O&M supports TE but is not specific to one program. This is the TE-related O&M that is not necessarily appropriate to include in the TE Plan Budget, nor appropriate to include in an individual program and portfolio cost-effectiveness calculation. Where portfolio support activities can appropriately be treated this way, they are reflected in the budget and identified as such. Staff's Exhibit 2203 illustrates this and is largely

[25] Staff/3200, Shierman/19 at 3-5.
[26] OAR 860-087-0020(1)(a) (emphasis added).

drawn from PGE's response to Staff's DR 331. Other aspects of our O&M in support of TE enable development and management of our TE-related workforce and overall TE support activity – and the development and implementation of the TE Plan itself – but are not properly considered part of the plan or the program specific activities and investments in support of TE encompassed by the plan. These base business activities are appropriately considered for cost recovery in the Company's general rate case, just as other activities in support of other planning efforts across the Company are base business activities addressed in the rate case.

Q. Are PGE's planning and administrative costs for TE excessive in comparison to other electric companies' costs?

A. No. While our TE-related O&M costs are higher than those of Pacific Power and Idaho Power, this is because a far greater percentage of the state's electric vehicles (60%) operate in our service area. Consequently, our TE-related activities encompassed in our accepted TE Plan and approved TE Budget are substantially more extensive than theirs and require a correspondingly higher level of support.[27] This appropriately reflects the state of the TE market we support in our respective service areas. Idaho Power, for instance, administers a TE Budget that had actual, total 2023 expenditures of $8,714 focused on marketing, training and education.[28] Pacific Power, consistent with their more extensive and varied Oregon service area, had actual, total 2023 TE Budget expenditures of $5,400,000.[29] PGE's actual, total 2023 TE Budget expenditures were $17,303,978, supporting a TE portfolio that is appropriately positioned to serve the 68% EV adoption growth rate projected for our service

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[27] Oregon Electric Vehicle Dashboard, accessed 9/19/2024 https://www.oregon.gov/energy/Data-and-Reports/Pages/Oregon-Electric-Vehicle-Dashboard.aspx

[28] Idaho Power's Annual TEP Report filed 4/26/24, https://edocs.puc.state.or.us/efdocs/HAQ/um2035haq328123024.pdf

[29] Pacific Power's Annual TEP Report filed 5/1/24, https://edocs.puc.state.or.us/efdocs/HAH/um2056hah328264056.pdf

area by the end of 2025. Establishing and maintaining the workforce and support structures to plan for and serve this growth as well as PGE's own transition to TE is an appropriate and necessary component of our base business O&M request.

Q. What is your recommendation regarding Staff's proposed reductions to the TE Department and TE Field Operations Department budgets?

A. Staff's proposed reductions should be rejected. Base business expenditures for both departments are appropriately scaled to support and execute customer-facing TE programs, measures and other activities described in the TE Plan, as well as continued program development, planning and administration, and (in the case of the TE Field Operations Department) PGE's own fleet and workplace charging needs.

E. TE-Related LEAs

Q. What does Staff propose regarding TE-related LEAs?

A. Staff proposes a rate base reduction of $1.1 million for amounts of past line extension allowances that Staff deems "excessive."[30]

Q. How do you respond to Staff's characterization that these LEAs were "excessive"?

A. The transportation-related line extension allowances were reasonable and prudent, and therefore warrant cost recovery. The line extensions in question were calculated based upon the best information available at the time and calculated in a manner consistent with the knowledge available at the time. PGE appropriately developed and then improved our methodology and practice to accommodate new technology (transportation electrification) into the line extension framework as more data became available about charging behavior. Transportation electrification is still new and, though Staff states that we could have

[30] Staff 3200, Shierman/34 at 7.

"reasonably known the capacity utilization of chargers for more than a decade now,"[31] significant learnings have occurred over this period. Charger utilization varies widely by use case and has changed dramatically since 2011. While PGE has had chargers in the field to study, it is unreasonable to assume that all TE load will be reflective of one use case, as there is diversity in charging behavior and utilization that depends on a variety of factors.

Q. What other claims does Staff make about the calculation of the TE-related LEAs?

A. Staff claims that in all site load forecasts reviewed, "the EV chargers have always had a separate line for the chargers' nameplate capacity,"[32] so their calculations only consider the EV-related load. Staff also claims that we are referring to load factors rather than capacity factors when we cite 5 percent for private sites and 14 percent for private sites. (Note, Staff mistakes the public and private sites for each other in their testimony,[33] which we correct here.) Staff states that we are "adjusting each site's nameplate capacity in a variety of ways and do not show a consistent conversion from an instantaneous demand metric to an energy metric."[34] Finally, Staff states that we should have used an "accurate, empirically derived capacity factor for the past three rate cases and has failed to do so."[35]

Q. How do you respond to these claims?

A. These claims ignore how the LEAs are structured. While EV-related load is often classified as its own line-item, it is not always, and other load is often included as separate lines within the same LEA so the LEA was calculated in total in both UE 394 and UE 416 for both EV-related and non-EV related load. Project M2949566, which is included in Staff Exhibit 3208,

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[31] Staff 3200, Shierman/35 at 9-10.
[32] Staff/3200, Shierman/35 at 4-6.
[33] Staff/ 3200, Shierman/36 at 3-4.
[34] Staff/ 3200 Shierman/36 at 12-14.
[35] Staff/3200 Shierman/37 at 1-2.

is a good example of this. Staff has revised their calculation in rebuttal testimony, but in Staff's exhibit in UE 416,[36] which is what their disallowance in this proceeding was based on that has not been revised, they simply applied their purported TE load factor of 0.4 to the entire load, leading to an incorrect calculation of the LEA. Where Staff states that we are using load factors, this is accurate, and Staff is also utilizing load factors. The 4% value is a load factor, as are the 5% and 14% we cite. In Staff's workpapers, they label the 4% value used as the load factor, so there is no difference. Where Staff observes that we are not adjusting nameplate capacities consistently, they are correct, but this is for good reason. Historically, we adjusted the capacity based on historical information where it was available, and more recently based upon the updated load factors, as discussed with Staff. While consistency is valuable in some contexts, EV charging is not consistent, and utilization varies based on the location and the use case. As EV charging infrastructure has gained popularity and more charging infrastructure goes live, we have refined our load factors to reflect what is observed in the field. Though Staff states that we should have used an empirically derived capacity factor this whole time, it would have been impossible to do so because the data simply was not available because the technology was so new. Now that we have access to more information, the TE-related LEA methodology has been revised accordingly, which is what Staff directed us to do in multiple places in their memo responding to our last filed TE plan in UM 2033.

Q. Staff questions why you use a "forecasting method that requires such added complexity."[37] How do you respond?

A. This forecasting method is necessary because we must estimate demand load to size the transformer needed to serve the new load. The calculation of demand load using connected

[36] UE 416, Staff/1907 (Jun. 13, 2023).
[37] Staff/3200, Shierman/36 at 16-17.

load is based on a PGE Design Standard, which is based on Oregon Electrical Specialty Code Alternate Method No. 09-01, which in turn provides demand factors based on the number of chargers. If we were to use the total nameplate capacity of the chargers (i.e. connected load), we would have to develop Capacity Factor assumptions to use for the annual energy estimates instead of Load Factors, which is much more complex. Meter usage data from actual EV sites is used to develop these assumptions, and meter data cannot provide connected load. Due to this nuance, utilizing the demand load and the load factor to estimate actual usage is the most appropriate method.

Q. What do you request of the Commission?

A. We request the Commission allow cost recovery of the LEAs from this proceeding, as well as the LEAs approved by the Commission within the prior two proceedings. The LEAs included in this proceeding and the prior two were calculated based on the best available knowledge at the time, and as such, are prudent.

V. Qualifications

Q. Allison Rowden, please state your educational background and experience.

A. I received a Bachelor of Arts degree from Eastern Oregon University. I have worked at PGE since 1998 with the majority of that time spent leading in our Customer Service area including Customer Care (call center serving residential, business and builders/developers in multiple channels – phone, social media and email) and Customer Revenue (Billing, Credit, Payment, Automated Metering, etc.).

Q. Dain Nestel, please state your educational background and experience.

A. I received a Bachelor of Arts from the University of Oregon and a Master of Business Administration from Kellogg School of Management. I have been in the energy industry since 2008 where I consulted to utilities on energy efficiency and demand response program design and implementation. I led ecobee's energy channel sales in the West starting in 2018, before joining PGE in 2019, where I now oversee our sales and outreach teams, program development and implementation teams (e.g., Flex Load and TE), as well as PGE's partnership with the Energy Trust of Oregon.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
2601	Staff response to PGE Data Request No. 26
2602	Staff response to PGE Data Request No. 27

Date: September 19, 2024

TO:
Jaki Ferchland
Portland General Electric Company
Manager, Rates & Regulatory Affairs
121 SW Salmon Street, 3WTC-0306
Portland, OR 97204

FROM: Nicola Peterson, Staff

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 435 – PGE Data Request No. 26

PGE Data Request No. 26:

Refer to Staff/3800, Peterson/5 lines 3-9. Refer also to Staff/3800, Peterson/5, lines 4-8. Please indicate whether Staff's recommended $2.0 million reduction for FERC Account 903 O&M is based on the $2.2 million DSG amortization discussed on page 5 or the 3-year average discussed on page 2.

OPUC Data Response No. 26:

Staff assumes the Data Request No. 26 should read: Refer also to Staff/3800, Peterson/2~~,5~~, lines 4-8.

The adjustment to FERC Account 903 of $2m is to bring this expense in line with the 3-year average, as stated in Staff/3800, Peterson/2, lines 4-8. The referencing of the inclusion of expenses relating to DSG amortization is further evidence that the amounts included in this account are inflated and not justified.

Date: September 19, 2024

TO:
Jaki Ferchland
Portland General Electric Company
Manager, Rates & Regulatory Affairs
121 SW Salmon Street, 3WTC-0306
Portland, OR 97204

FROM: Nicola Peterson, Staff

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 435 – PGE Data Request No. 27

PGE Data Request No. 27:

Refer to Staff/3800 Peterson/3, stating “averages are a good indication of a level of costs which are reasonable and justifiable.” Please specify for what types of costs and/or in what contexts Staff has previously supported departure from historical averages for setting future Test Year O&M amounts?

OPUC Data Response No. 27:

Staff objects to this data request as considering the 5-business day reply requirement of this request, Staff is unable to complete an extensive search of all the rate cases that have ever come before the commission.

Notwithstanding this objection, Staff’s opinion is that given the general principle that “averages are a good indication of a level of costs which are reasonable and justifiable,” any departure from this would be for:

1. Errors or omissions.
2. Known transfers or delays in expenditure (as adjusted for in FERC Account 908).
3. Additional expenses that would be ongoing and cannot be covered by the base level of budgeted expenditures.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 435

Transmission and Distribution

PORTLAND GENERAL ELECTRIC COMPANY

Surrebuttal Testimony of

Kellie Cloud
Franco Albi
Joey Baranski

October 1, 2024

Table of Contents

I. Introduction

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

A. My name is Kellie Cloud. I am employed by PGE as the Senior Director of Wildfire and Operational Compliance.

My name is Franco Albi. I am employed by PGE as the Director of Regional Integration and Systems Evolution.

Our qualifications appear in PGE Exhibit 1600.

My name is Joey Baranski. I am employed by PGE as Director of Strategic Grid Planning. I am adopting the reply testimony of Kellie Cloud, Franco Albi, and Kevin Putnam previously filed in this proceeding in PGE Exhibit 1600.

My qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to respond to the rebuttal testimony and proposed adjustments raised by the Staff (Staff) of the Oregon Public Utility Commission (OPUC or Commission) and the Alliance of Western Energy Consumers (AWEC) (collectively, Parties) with respect to PGE's transmission and distribution (T&D) operations and maintenance (O&M) expenses. We also respond to The Oregon Citizens' Utility Board (CUB) rebuttal testimony comments regarding our answers to their inquiries concerning the January 2024 storm event.

Q. How is the remainder of your testimony organized?

A. After this introduction, we have six sections:

- Section II – Overview & Summary
- Section III – Utility Asset Management (UAM) O&M Expenses
- Section IV – Routine Vegetation Management (RVM) O&M Expenses

- Section V – Virtual Power Plant (VPP) O&M Expenses
- Section VI – T&D Capital Project Adjustments
- Section VII – January 2024 Storm Response
- Section VIII – Qualifications

II. Overview and Summary

Q. Please provide a summary of your testimony.

A. Section III of our testimony addresses Staff's proposal in rebuttal testimony to continue to hold Utility Asset Management (UAM) O&M expenses at the same level as those approved in Docket UE 416.[1] We specifically counter Staff's argument and demonstrate how we have met the burden of proof to justify our requested increase for the 2025 Test Year.

Section IV of our testimony addresses Staff's and AWEC's rebuttal testimony arguments for adjustments to our Routine Vegetation Management (RVM) O&M test year expenses. Despite addressing Staff and AWEC's concerns from their opening testimony, and on some issues, achieving agreement around crew resource calculations, both Parties continue to propose their original adjustments.

In Section V of our testimony, we highlight areas of understanding with Staff on our 2025 Test Year Virtual Power Plant (VPP) Program but raise concerns with Staff's remaining test year adjustment and proposal for another, superfluous standalone reporting docket.

Section VI addresses Staff's rebuttal testimony around T&D Capital Project adjustments. Specifically, we propose another option for Commission consideration regarding Staff's alternative proposal for T&D capital additions.

Section VII of our testimony provides additional information regarding our response to the January 2024 storm event.

[1] See *In the Matter of Portland General Electric, Request for a General Rate Revision,* Docket UE 416, Order No. 23-476, (Dec 18, 2023).

Q. What do you recommend of the Commission?

A. We ask that the Commission approve PGE's UAM, RVM, and VPP O&M 2025 Test Year expenses. We recommend the Commission approve PGE's reply testimony proposals as it relates to the three specific T&D capital additions projects identified by Staff based on the projects' actual final values as of December 1, 2024. Lastly, we request that the Commission not accept Staff's alternative approach to remove all T&D project contingencies and stipulate that PGE can update rate base to include the actual costs incurred on these projects prior to the rate effective date.

III. Utility Asset Management (UAM) O&M Expenses

Q. Please briefly summarize PGE's request concerning UAM O&M expenses.

A. PGE seeks recovery of $5.8 million in increased UAM O&M expenses for the 2025 Test Year, largely driven by increased contract labor costs and increased volume of inspections/ corrections work across PGE's system.[2]

Q. Please summarize Staff's rebuttal testimony regarding PGE's UAM request.

A. Staff continues to propose a reduction of the UAM Test Year amount to hold PGE's request to $25.9 million, consistent with the results of UE 416.[3] Staff again asserts, despite all of PGE's additional detailed responses to inquiries, that PGE has still not met the burden of proof to justify the requested increase.

Q. In its rebuttal testimony, how did Staff justify their continued UAM adjustment?

A. In defense of its original adjustment, Staff relies on rebutting PGE's evidence from our reply testimony. Staff focuses on the following items:

- Reliance on a simple escalation of 2023 actual UAM spending levels for the basis of the forecast 2025 Test Year amounts.
- Use of the All-Urban Consumer Price Index (CPI) as an index for year over year escalation.
- Sufficiency of evidence provided to justify the 2025 Test Year amount.

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[2] PGE/400, Bekkedahl – Felton/9-10.
[3] Staff/1300, Mondragon/21; Staff/3500, Mondragon/16.

Q. Do you agree with Staff's continued reliance on a simple escalation of 2023 actuals to project 2025 Test Year amounts?

A. No. In their rebuttal testimony, Staff did not address their deviation from past Commission precedent on the use of industry-specific information being more appropriate than the use of a simple CPI index for estimating test-year expenses.[4] In this record, PGE provided a detailed justification for our forecast 2025 Test Year UAM expenses.

Q. What does Staff argue concerning the use of the All-Urban CPI as an escalator?

A. In their rebuttal testimony, Staff argues the merits of using the All-Urban CPI versus other inflation indices and infers PGE is "forum shopping" for a more favorable escalator.[5]

Q. Does Staff's argument accurately reflect PGE's concern about the use of an inflation index to forecast test year amounts?

A. No. In our reply testimony, PGE did not argue that another inflation index is a better indicator for use in year over year calculations or offer up another index in an attempt to "forum shop." We simply argued that Staff should follow Commission precedent and use the better, industry-specific information they had available to them to forecast the test year amounts.[6]

Q. Do you agree with Staff's argument that PGE did not provide sufficient evidence to justify the requested increases?

A. No. In fact, in their rebuttal testimony, Staff details the extensive amount of information PGE provided in justification for the increase in UAM activity and spending.[7]

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[4] See *In the Matter of Pacificorp, dba Pacific Power, Request for a General Rate Revision*, Docket UE 374, Order No. 20-473, (Dec 18, 2020).
[5] Staff/3500, Mondragon/14.
[6] PGE/1600, Cloud – Albi – Putnam/10.
[7] Staff/3500, Mondragon/15, at 6-7, 10-13, 18-21.

Q. Do you agree with Staff's footnote to PGE's response to OPUC Data Request No. 758 (OPUC DR 758) as insufficient?

A. No. In OPUC DR 758, Staff asked for a spreadsheet that demonstrates, at a minimum the following items as relates to the 2025 Test Year amounts:[8]

> *a. Starting value,*
> *b. Identification and application of the escalation factor, and*
> *c. Resulting amount.*

PGE's response to this data request, included a spreadsheet with individual cost element breakouts of all UAM activities with the starting value, the identification of the escalation factor, and the resulting amount that reflects our 2025 Test Year amount. In the response, we also added an additional level of breakout for the Outside Services category to support the numeric values in our narrative response.[9]

Q. Do you agree that Staff did not have the narrative or arithmetic information necessary to conclude that the Company's proposed test year amount is just and reasonable?

A. No. A review of the record in this case clearly shows that PGE has been responsive and thorough in developing the justification for its 2025 Test Year amount. As Staff's own rebuttal testimony highlights, PGE has provided, "plenty of written explanation for why the Company is requesting an increase."[10] Where Staff requested additional information via data requests, PGE was timely and thorough in its responses.[11]

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[8] Staff Data Request Item No. 758
[9] PGE Exhibit 2701 CONF
[10] Staff/3500, Mondragon/15 at 6-7.
[11] PGE response to Data Request Items No. CONF 653, CONF 654, CONF 655, 757, CONF 758, CONF 765, CONF 766, 767, 768, 769, 770, 771, 772, 773

Q. What is your recommendation concerning PGE's filed UAM O&M expense forecast?

A. PGE asks the Commission to reject Staff's recommended $5.9 million adjustment and approve PGE's original cost recovery request.

IV. Routine Vegetation Management (RVM) O&M Expenses

Q. Please briefly summarize PGE's request concerning RVM O&M expenses.

A. PGE seeks recovery of $4.8 million in increased vegetation management expenses for the 2025 Test Year, largely driven by increased contract labor costs.[12] PGE provided substantial detail regarding the nature and scope of these expenses in direct testimony, reply testimony, workpapers, and responses to discovery requests.

A. Staff Recommendations: RVM O&M Expenses

Q. Please summarize Staff's rebuttal testimony regarding PGE's RVM request.

A. Staff continues to propose a reduction of $6.2 million to the 2025 Test Year amount for RVM O&M expenses. In their opening testimony, Staff heavily based their reduction on recalculating the 2024 and 2025 outside crew costs.[13] After further review of workpapers, and discussion with PGE, Staff now agrees that the new calculation of test year crew estimates are more precise.[14] Staff then details the 28 individual data request responses provided by PGE as support for the test year amount.[15] Despite agreement on the 2025 Test Year crew complements, and the extensive evidence provided in data request responses, Staff is still proposing a reduction.

Q. If Staff now agrees with PGE's 2025 outside crew costs, which was the basis of their adjustment in their rebuttal testimony, why are they still proposing an adjustment?

A. Despite, heavily basing their original reduction on a recalculation of crew costs, and now agreeing that PGE's method is more precise, Staff is presenting an entirely new argument that questions whether, "certain aspects PGE's outside labor budget are appropriately

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[12] PGE/400, Bekkedahl – Felton/8.
[13] Staff/3500, Mondragon/2 at 4.
[14] Staff/3500, Mondragon/3.
[15] Staff/3500, Mondragon/4.

parameterized".[16] Having been satisfied on the accuracy of PGE's crew cost projections, Staff proposes a new area of analysis and tries to correlate contact violations with crews employed and actual RVM spend.[17]

Q. Is it appropriate in rebuttal testimony for Staff to change their justification for their original adjustment based on a completely new set of analysis?

A. No. In a contested case process, testimony phases are meant to be a reductional process, meant to reduce or narrow the scope of issues for Commission consideration. The very nature of the testimony scheduling process, of shrinking the amount of time between subsequent rounds, ensures that Parties not introduce or need to address a completely new set of arguments or analysis. Parties are not able to provide a sufficient and adequate response to new items given the compressed schedule.

Q. Even with this concern, do you have any comments regarding Staff's new analysis around the level of RVM spending and contact violations?

A. Yes. While concerned about the introduction of new analyses late in the process, PGE must offer a counter to Staff's findings as it relates to the correlation between RVM spend and contact violations. As was covered extensively in PGE's surrebuttal testimony in the UE 416 General Rate Case Docket (UE 416), the correlation between contact violations and RVM spend has not been statistically demonstrated.[18]

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[16] Staff/3500, Mondragon/5 at 15-16.
[17] Staff/3500, Mondragon/5-8.
[18] *In the Matter of Portland General Electric Company Request for General Rate Revision; 2024 Annual Update Tariff*, Docket UE 416, PGE/3600, Putnam-Ferchland/10-23 (Sept. 11, 2023).

Q. Could weather and growing conditions affect the historic relationship between contact violations and RVM spend?

A. Yes. Staff, in their rebuttal testimony, relies heavily on the assumed relationship between contact violations identified in historic OPUC Safety Staff audits and RVM actual spend. Staff, however, fails to measure or account for the strong historical variation created by weather and growing season characteristics. Growing conditions change seasonally and vary year-by-year. For example, a warmer and wetter spring can lead to above-average tree growth starting earlier in the season. In addition, power lines sag during high temperatures, impacting the proximity of vegetation. Depending upon when OPUC Safety Staff conduct their audits, these environmental conditions would impact their observations of possible contact violations and cause variations unrelated to actual RVM spend.

Q. Do you have other concerns regarding the use of contact violations from OPUC Safety Staff annual audits in assessing the historic effectiveness of RVM spend?

A. Yes. As summarized in UE 416 PGE surrebuttal testimony, OPUC Safety Staff's annual audits are not conducted with sufficient consistency or statistical significance to draw a correlation between contact violations and RVM spend.[19] It would be unreasonable to draw correlations based on an underlying methodology that is not statistically sound and cannot be applied uniformly or consistently year-to-year.

Q. Do you have any comments concerning the Staff recommendation for the disallowance of the existing four Forestry positions?

A. Yes. Staff recommends an adjustment of four Forestry positions to avoid funding these positions twice on the premise that these positions were already included in UE 416 rates and

[19] UE 416, OPUC/3600, Putnam–Ferchland/12-21.

that PGE's ask in this case is incremental. The four Forestry positions are the same four FTEs in both rate cases and are not incremental. As such, funding these positions in UE 435 is not a double counting but a continuance of UE 416 rates. To adopt Staff's recommendation would be removing the existing positions that were already incorporated in UE 416.

Q. What is your recommendation concerning PGE's filed RVM O&M expense forecast?

A. PGE asks the Commission to reject Staff's recommended $6.2 million adjustment and approve PGE's original cost recovery request.

B. AWEC Recommendations: RVM O&M Expenses

Q. Please describe the proposed adjustment by AWEC regarding RVM O&M expenses.

A. In opening testimony, AWEC recommended that PGE hold RVM expenses flat between 2024 and 2025.[20]

Q. Does AWEC change their position in rebuttal testimony?

A. No. AWEC continues to recommend a reduction back to 2024 levels for RVM O&M expenses.[21]

Q. In its rebuttal testimony, how did AWEC justify their continued RVM adjustment?

A. AWEC states that their original critique of RVM O&M expenses was in the larger context of overall increases in distribution non-labor O&M expenses. Without critiquing PGE's 2025 Test Year RVM amount, AWEC makes the global argument for PGE to identify areas to reduce its O&M budget.[22]

[20] AWEC/100, Mullins/30.
[21] AWEC/300, Mullins/24.
[22] *Id.*

Q. Does AWEC provide any new critique of the effectiveness of PGE's current RVM spend or the reasonableness of the 2025 Test Year amount ask in this case?

A. No. AWEC still has not inquired through data requests or provided additional narrative in their rebuttal testimony to counter the effectiveness of our current RVM spend or the reasonableness of our 2025 Test Year expense ask. They simply state that RVM rates should be held flat at 2024 levels in consideration of overall increases in distribution non-labor O&M expenses.[23]

Q. Does AWEC provide evidence against the use of the Asplundh contract rates in calculating the 2025 RVM Test Year amount?

A. No. AWEC still does not take issue with the application of the 2025 Asplundh contract rates to the Company's RVM work.

Q. Does AWEC address the reduction in customer benefits that would occur from not reflecting the Asplundh multi-year contract in the test year amount?

A. No. AWEC does not address the incentive to enter into multi-year contracts, and the loss of customer benefit that could result from holding RVM expenses flat between 2024 and 2025.

Q. What is your recommendation concerning PGE's filed RVM O&M expense forecast?

A. PGE asks the Commission to reject AWEC's recommended $4.3 million adjustment, duplicative of Staff's recommended RVM adjustment, and approve PGE's original cost recovery request.

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[23] AWEC/300, Mullins/24.

V. Virtual Power Plant (VPP) O&M Expenses

Q. Please briefly summarize PGE's request concerning VPP O&M expenses.

A. PGE seeks recovery of $4.0 million associated with implementing the VPP program. These costs enable the Company to effectively optimize distributed energy resources (DERs) and flexible loads to provide substantial benefits for customers, including contributing to decarbonization, advancing customer and community resilience, facilitating customer engagement, and unlocking additional grid services.[24]

Q. Please summarize Staff's rebuttal testimony regarding PGE's VPP request.

A. Of Staff's original $4.0 million VPP adjustment, Staff's rebuttal testimony reinstates $2.5 million due to the mistakenly double counted adjustment to FTE levels.[25] Staff also acknowledges **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Staff expresses their appreciation of the additional information provided by PGE concerning the actual effectiveness of the VPP to date and acknowledges that this information could provide Staff with some assurance that the VPP ask is an effective use of ratepayer

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[24] PGE/400, Bekkedahl-Felton/13-14.
[25] Staff/2400, Dlouhy/7.
[26] *Id.*
[27] Staff/1700, Dlouhy/11.

money.[28] Staff caveats this statement with the belief that the VPP warrants its own standalone filing.[29]

Ultimately, Staff revises its adjustment from a $4.0 million reduction to a $1.5 million reduction to reflect the mistakenly, double-counted labor expense. While Staff now agrees with PGE, that grant funds are not being double recovered, they do not withdraw this amount used to justify their original adjustment.[30]

Q. Do you agree with Staff's $1.5 million VPP test year expense adjustment?

A. No. While PGE appreciates Staff's removal of their originally proposed VPP adjustment to accurately reflect FTE adjustment, we do not agree with the remaining proposed adjustment related to grant funds. In justifying their continuance of the adjustment, Staff directly correlates recovery of grant funding dollars with Staff's perceived performance of the VPP. While Staff acknowledges the value of PGE's VPP, and the need to provide proper incentives to enhance its capabilities,[31] they are putting customer benefits at risk by not authorizing dollars directly linked to cost-sharing grant commitments.

Q. Do you agree with Staff's position that PGE has not provided sufficient evidence to justify the authorization of increased VPP spending?

A. No. Staff acknowledges the value of the additional information provided by PGE of the effectiveness of the VPP since the last rate case filing.[32] It appears that Staff's hesitancy to agree with the effectiveness of the VPP has less to do with the analysis provided in this docket and more to do with the venue in which it was submitted. Staff specifically states that they

[28] Staff/2400, Dlouhy/8.
[29] Staff/2400, Dlouhy/9.
[30] *Id.*
[31] Staff/1700, Dlouhy/10.
[32] Staff/1700, Dlouhy/8.

would perhaps be more comfortable with the cost effectiveness of the VPP if it had been presented in a planning docket.[33] Staff provides no reasoning for why the general rate case (GRC) proceeding precludes them from gathering the information needed to make this assessment.

Q. Do you agree with Staff's assessment that an annual, standalone filing is the only way to determine the cost-effectiveness of the VPP?

A. No. Staff states they are unable to fully understand the cost-effectiveness of the VPP because it fluctuates throughout the year and is comprised of multiple programs.[34] Their proposed resolution of this issue is for the Commission to require an annual, standalone VPP filing. As outlined in PGE's reply testimony, it is our position that the Distribution System Planning (DSP) docket is the correct forum to address Staff's questions about VPP and its ongoing contribution to operations and how the various programs fit together as a cohesive asset.[35] Like other resources, VPP available capacity, similar to other power plants, fluctuates based on a variety of factors, including but not limited to weather, system and customer conditions - and these are reflected in the planning assumptions included in the DSP. A standalone docket does not provide anything additional that could not be discussed in the GRC or the DSP docket. PGE welcomes the opportunity to clarify assumptions through the GRC and DSP dockets to address Staff's questions.

Q. What do you recommend regarding Staff's proposals on VPP?

A. We request that the Commission approve PGE's $4.0 million increase as this represents necessary funding to further the development of the VPP. PGE continues to agree to offering

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[33] Staff/2400, Dlouhy/8.
[34] Staff/2400, Dlouhy/9.
[35] PGE/1600, Cloud – Albi – Putnam/26.

a workshop to the Parties to show how VPP, ADMS[36] and DERMS benefit participants and intersect with one another. Finally, we request the Commission reject Staff's proposal to open yet another reporting docket when there are already multiple locations where information is already provided and reported to the Commission regarding VPP.

[36] Advanced Distribution Management System (ADMS).

VI. T&D Capital Project Adjustments

Q. Please briefly summarize PGE's request concerning T&D capital additions.

A. PGE seeks recovery of its incremental T&D investments made to serve customers through December 31, 2024,[37] including crucial resiliency and safety-related investments in grid modernization, substations, and enhanced distribution systems.

Q. Please describe Staff's rebuttal testimony as relates to PGE's T&D capital investments.

A. In their rebuttal testimony, Staff acknowledges the impacts of PGE's cost updates to the three specific capital projects identified for adjustment in its opening testimony.[38] Staff also disagrees with PGE's justification for the need of project contingencies and maintains its position to remove T&D capital project contingencies from rate base.[39] Staff proposes an alternative approach for all T&D capital projects, where all project contingency funds would be removed and PGE would have the opportunity to update rate base to include the actual costs incurred prior to the rate effective date up to the amount of the individual forecasts assumed for PGE's proposed Test Year.[40]

Q. Did Staff address the justification or need for project contingencies as relates to project planning or the consequences to customers if project contingencies are not allowed?

A. No. Staff did not speak to PGE's concerns raised in our reply testimony[41] and simply says Staff does not support this approach.[42]

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[37] PGE/400, Beddedahl-Felton/3.
[38] Staff/3400, Ball/13.
[39] Staff/3400, Ball/13-14.
[40] Staff/3400, Ball/14.
[41] PGE/1600, Cloud–Albi–Putnam/31.
[42] Staff/3400, Ball/14.

Q. Do you agree with Staff's alternative approach around updating rate base for actual costs for the T&D capital projects included in this case?

A. No. Staff's proposed alternative approach is in many ways similar to the capital attestation process proposed by AWEC in their opening testimony.[43] PGE reply testimony responded to AWEC's arguments around the prudent need of an attestation process and the inherent imbalance of AWEC's proposal.[44] Many of PGE's concerns with AWEC's capital attestation proposal apply to Staff's alternative approach.

Q. Do you have any specific concerns regarding Staff's alternative approach for the T&D capital projects included in this case?

A. Yes. In developing their alternative approach, Staff is making the argument that an attestation process is necessary to determine the prudence of PGE capital projects. As stated previously, PGE has provided over 2,000+ pages of discovery responses regarding the capital projects included in this case. PGE counters that the evidentiary phase of this proceeding has afforded all Parties the opportunity to assess the prudence of requested capital investments, with or without an attestation process.

Q. What do you recommend regarding Staff's proposal on T&D Capital Project?

A. PGE reiterates its position from our reply testimony and proposes to adjust the final plant in service for the three specific projects identified by Staff based on the projects' actual final values as of December 1, 2024. We also request that the Commission not accept Staff's alternative approach to remove all T&D project contingencies and stipulate that PGE can

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[43] AWEC/100, Mullins/23-27.
[44] PGE/1300, Batzler-Meeks/60-63.

update rate base to include the actual costs incurred on these projects prior to the rate effective date.[45]

[45] PGE/1300, Batzler-Meeks/60-63.

VII. January 2024 Storm Response

Q. Please provide a summary of CUB's response to the January 2024 storm response testimony offered in PGE's reply testimony.

A. CUB takes issue with what they see as the tone of PGE's reply comments and outlines the challenges and responses PGE has experienced as relates to the January 2024 Storm. CUB raises specific concerns with the content of recent PGE Major Event reporting as relates to problems with the Outage Management System.[46] While CUB raises this as an issue CUB proposes no disallowances in this case and states that they are encouraged with PGE's reply testimony and our efforts to resolve these issues.[47]

Q. Do you have any additional comments concerning PGE's Major Event reporting?

A. PGE has 30 business days from the conclusion of a major event to file a major event report per statutory requirement[48]. This is a short window of time to gather, validate, and perform corrections on data for the major event report. Historically for storms that impacted customers at the magnitude of the January 2024 storms[49], data validation and cleanup has taken months post storm conclusion. PGE strives to get the data as accurate as possible[50] and submitted within the required timeline.

Q. Does this conclude your testimony?

A. Yes.

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[46] CUB/400, Jenks/21.
[47] CUB/400, Jenks/21-22.
[48] Oregon Administrative Rule 860-023-0161.
[49] PGE/1600, Cloud–Albi–Putnam/36-42.
[50] Oregon Administrative Rule 860-023-0101(3).

VIII. Qualifications

Q. Joey Baranski, please describe your qualifications.

A. I received a Bachelor of Science Degree in Electrical Engineering from Portland State University. My employment with PGE started in April 2006 and I have worked as a SCADA Engineer, Substation Technical Services Manager, Manager of Operational Technology Services, Senior Manager of Integrated Engineering Services, Director of Asset Management, and Director of Strategic Grid Planning. Prior to Portland General Electric I worked as a contractor for PNGC Power.

List of Exhibits

PGE Exhibit	**Description**
2701C	PGE CONFIDENTIAL Response to Staff Data Request Item No. 758

UE 435

Exhibit 2701 is CONFIDENTIAL pursuant to General Protective Order No. 23-132

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 435

Production

PORTLAND GENERAL ELECTRIC COMPANY

Surrebuttal Testimony of

Debbie Powell
Brian Clark
Kori Mead

October 1, 2024

Table of Contents

I. Introduction and Summary

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

A. My name is Debbie Powell. I am employed by PGE as the Vice President of Utility Operations.

My name is Brian Clark. I am the Senior Director of Thermal Generation and Planning. Our qualifications appear at the end of PGE Exhibit 1700.

My name is Kori Mead. I am a Senior Energy Supply Procurement Originator. My qualifications appear at the end of this exhibit. I am adopting the reply testimony of Debbie Powell and Brian Clark previously filed in this proceeding in PGE Exhibits 500 and 1700.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to respond to rebuttal testimony from the Staff (Staff) of the Oregon Public Utility Commission (OPUC or Commission), the Alliance of Western Energy Consumers (AWEC), and the Citizens' Utility Board (CUB) (collectively, Parties) with respect to PGE's 2025 test year operations and maintenance (O&M) generation amounts and generation related capital projects.

Q. Has any party adjusted their previous recommendations in rebuttal testimony?

A. Yes. Staff has modified their previous recommendation regarding PGE's Diesel Particulate Filter (DPF) Program, by removing their previously proposed $17.8 million capital adjustment and in its place proposing a capital attestation process.[1] Additionally, Staff has removed their proposed $5 million punitive adjustment related to RFP data, and they accepted the $2 million downward adjustment related to Clearwater O&M and the Custer County fee.

[1] Staff/3400, Ball 17-18 at 21-03.

Q. What adjustments proposed by Parties remain the same from opening testimony?

A. The following recommendations from Staff, AWEC, and CUB largely remain unchanged from their opening round of testimony:

1. AWEC proposes an adjustment of $5.8 million to generation non-labor O&M on the basis of comparing 2023 to 2025 and applying an escalator. This adjustment is roughly $22 thousand lower than originally proposed, as AWEC corrected errors in their analysis.
2. Staff continues to propose capital adjustments of $14 million and $44 million for Constable and Seaside respectively, on the basis of comparing RFP costs to GRC costs.
3. Staff has updated its recommendations for Fleet expenses. Initially, they proposed a $5.3 million reduction related to "premature replacement" of PGE vehicles. This proposal has now been revised to a $3.1 million reduction for PGE's Fleet investments. Staff also maintains its proposal for a $2.7 million reduction related to "net EV premium." This $2.7 million reduction comprises two components: $2.4 million previously settled in case UE 416, and a revised downward adjustment of $231,000 for 2024 investments.

Q. Please summarize PGE's response to these proposals.

A. PGE responds as follows to the issues listed above:

1. PGE disagrees with AWEC's proposal to rely on 2023 actual spend to set amounts for 2025 instead of PGE's comparison of generation non-labor O&M from 2024 to 2025. AWEC's reliance on 2023 spend levels fails to provide the most accurate prediction of costs during the 2025 Test Year and ignores the results of the regulatory

review process and outcome in UE 416 which established the basis for PGE's 2024 budget. Furthermore, AWEC neglects performing a nuanced and accurate escalation in their recommendation in favor of a single broad escalation, resulting in an inaccurate forecast. PGE recommends that the Commission reject AWEC's proposal and instead approve PGE's generation non-labor O&M forecast for 2025.

2. PGE is agreeable to Staff's proposal regarding the DPF Program. The concept of an officer attestation for a capital project of this size is similar to the proposal that PGE lays out in PGE Exhibit 2400. In accordance with this proposal, there would be one attestation that would occur 45 days after the rate effective date. PGE recommends that the Commission accept Staff's proposal, as long as it is in line with the attestation methodology in PGE Exhibit 2400.
3. PGE disagrees with Staff's $14 million and $44 million adjustments for Constable and Seaside since those adjustments stem from a fundamental misstatement of RFP price scoring workbooks and the costs represented therein. PGE also disagrees with Staff's criticism of the 2021 RFP process because there are checks and balances that were created through a public process, including a Commission appointed Independent Evaluator that verifies project price scoring. PGE recommends that the Commission reject Staff's proposal as it is based on faulty analysis and assumptions. Please note that discussion of the tracker proposals for Constable and Seaside are included in PGE Exhibit 2200.
4. PGE disagrees with all of Staff's proposals related to fleet and asks that the Commission reject the proposals. PGE will demonstrate that even the State of Oregon's governmental agencies vehicle policies in relation to both vehicle

replacement and EV adoption are contrary to Staff's proposal, which do not fully contemplate safety, emissions, and efficiency in fleet management standards.

II. Generation Non-Labor O&M

Q. Does Staff continue to propose adjusting PGE's non-labor generation O&M?

A. No. Staff no longer proposes to adjust PGE's non-labor generation O&M, as PGE removed the $2 million Custer County Fee identified by Staff within the updated revenue requirement included in reply testimony.

Q. Has AWEC modified its non-labor generation O&M proposal in rebuttal testimony?

A. AWEC proposes an adjustment to Power Ops and Generation of $5.8 million, which is a slight decrease from the adjustment proposed in their opening testimony after correcting for some errors in their analysis.[2]

Q. How does AWEC respond to PGE's argument that their adjustment to generation non-labor O&M was unspecific and unsupported in nature?

A. Instead of addressing PGE's argument by showing any area of overspend relative to either PGE's 2024 budget or 2023 actuals, which were both provided at the outset of the proceeding, AWEC asserts that PGE did not propose any specific adjustments from 2023 actual costs to PGE's 2025 test year forecast, while ignoring the explanation provided by PGE in opening testimony to show how PGE's 2025 test year forecast is prudent.[3]

Q. Has PGE justified its 2025 test year non-labor O&M expenses?

A. Yes. PGE is seeking a $2.46 million increase in non-labor production O&M over 2024 levels.[4] PGE's 2024 non-labor O&M expenses for production were thoroughly reviewed for prudence in UE 416, and the revenue requirement adopted at the end of that proceeding serves as the basis of comparison to PGE's 2025 test year expenses in this case. PGE then showed how

[2] AWEC/300, Mullins/26 at Table REB-2.
[3] AWEC/300, Mullins/25 at 15.
[4] Inclusive of the Custer County Fee 2025 reduction.

expenses since 2024 have changed, which fully bridges the gap from current prudent spending to requested test-year spending.

Q. Is AWEC's response logically consistent and well-supported by the available evidence?

A. No. As stated in reply testimony, comprehensive work papers were provided to parties at the outset of this proceeding that provided accounting line-item detail for 2021-2023 actual costs, 2024 budgeted costs, and the 2025 test year forecast.[5][6] AWEC seems to have excluded these comprehensive workpapers when creating their proposal, and instead have used a simple escalation.

Q. AWEC states that "nothing that was agreed in the [UE 416] stipulations prevents AWEC from reviewing PGE's actual costs and making recommendations based on its review in this proceeding."[7] How does PGE respond?

A. We agree that if AWEC sees it necessary to conduct a detailed review of PGE's actual 2023 costs and make recommendations regarding PGE's 2025 future test year, they were free to do so. However, AWEC has provided no evidence to suggest that such an analysis was actually performed. AWEC simplistically applies a percentage escalator to PGE's 2023 actual costs and makes no specific adjustments, despite having the data to do so.[8]

Q. Does PGE have any other response to AWEC?

A. If AWEC had proposed adjustments based on a detailed comparison between 2023 actual spending and the 2025 test year, PGE would have responded to those adjustments and addressed the appropriateness. However, applying a blanket escalation without accounting for specific cost elements and their unique escalators is overly simplistic. Such an approach fails

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[5] *See* PGE Workpaper titled "2025 Production Work paper_FY 2023_2.8.24"
[6] PGE/1700, Powell – Clark/7 at 15.
[7] AWEC/300, Mullins/22-23 at 23-01.
[8] PGE/1700, Powell-Clark/7-8 at 15-02.

to address PGE's specific operational needs and cannot serve as an accurate or reliable basis for business planning.

Q. Does AWEC's methodology at least incorporate differentiated cost escalators based on the various categories of expenses?

A. No, even though PGE previously provided AWEC and parties information on the cost escalators used by PGE. In April of this year, AWEC sent PGE a data request asking for an explanation of how the forecasts for operating expenses and revenues were developed and if the operating expenses and revenues were forecast based on applying an escalation factor used for each line item in PGE's forecast.[9] PGE explained that the 2025 forecast was based upon PGE's 2024 budget, which reflects PGE's 2024 general rate case result as approved in Commission Order No. 23-386. We explained that to forecast the 2025 test year, the 2024 budget was escalated and adjusted for known and measurable changes. We then provided the 2025 escalation factors applied by cost element, as shown below in Table 1.

[9] AWEC Data Request No 006.

Table 1
Escalations by Cost Elements

Cost Element	Escalation Rate
1101	4.000%
1102	5.667%
1103	4.000%
1200	6.000%
1401	4.000%
1402	6.000%
1501	4.000%
1502	1.034%
1601	4.000%
1602	1.034%
2101	1.010%
2110	1.010%
2111	1.026%
2200	1.034%
2250	1.034%
2300	1.034%
2400	1.026%
2500	1.026%
2502	1.026%
2600	1.026%
2650	1.026%
2701	1.026%
2801	1.034%
2850	1.026%
5104	4.667%

In May, PGE was then asked in a data request from Staff[10] to provide the source, documentation, and support for escalation factors used to escalate each cost element in response to the previously mentioned AWEC data request. PGE's response provided that different escalators are utilized for different cost elements, which are more targeted and accurate than escalating every type of cost at the same rate. This more precise approach to determining escalations for non-labor O&M has been previously supported by the Commission for non-labor expenses over the All-Urban CPI.[11]

[10] OPUC Data Request No. 434.
[11] *See* In the Matter of PacifiCorp Request for a General Rate Revision, Docket UE 374, Order No. 20-473 at 111 (Dec 18, 2020).

In addition to AWEC not proposing reductions based on a review of PGE's 2025 test year in comparison to the 2024 budget or 2023 actual spending, AWEC also does not apply nuanced cost escalators. Instead, AWEC employs overly generalized inflation escalators to make sweeping cuts to the test year. Accordingly, PGE affirms that its comparison of a 2024 base year to 2025 is far more accurate as a point of comparison.

Q. Does PGE have any evidence that their 2024 budget is an accurate representation of actual costs?

A. Yes. As Table 2 shows below, PGE's 2024 initial budget is accurate when compared to eight months of actuals and four months of budget.

Table 2[12]
UE 435 2024 Actuals and Budget Comparison

	2023 Actuals	**2024 Budget**	**2024 8+4 Actuals and Budget**	**2025 Forecast**
Total Non-Labor Generation:[1]	$78,244,204	$91,231,746	$92,199,374	$93,690,393

1. This amount is inclusive of Generation amounts related to Environmental, MMA, and IT. Also, it is inclusive of the Custer County Fee 2025 reduction.

PGE is on track to spend the amounts budgeted for 2024, which served as the basis of comparison in this rate review and supports that PGE's 2024 budget is the most prudent point of comparison for PGE's 2025 test year and PGE provided the parties in PGE's previous rate case, including AWEC, evidence showing why the generation non-labor O&M amounts PGE was seeking for 2024 were justified.[13]

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[12] PGE Workpaper "2025 Production Work paper_FY 2023_8+4 2024."
[13] *See* PGE Exhibit 2801 for all UE 416 testimony that justified PGE's 2024 generation non-labor O&M.

Q. What does PGE recommend regarding AWEC's generation non-labor O&M adjustment?

A. PGE recommends that the Commission reject AWEC's non-labor generation O&M adjustment on the basis that the underlying analysis is flawed, and that PGE has formulated its 2025 forecast as accurately as reasonably possible.

III. Diesel Particulate Filter Installation Project

Q. Has Staff modified its proposal regarding the Diesel Particulate Filters (DPF) Project in rebuttal testimony?

A. Yes. Staff has withdrawn their proposed capital reduction of $17.8 million. Instead, citing scope and cost modifications to the program over the course of UE 435,[14] Staff's current recommendation is for PGE to provide an officer attestation for the DPF program that will only allow the actual costs for completed DPF AWOs that are in service by the rate effective date.[15] Under this proposal, the attestation would include project completion dates and actual costs for each AWO.

Q. What is the DPF project?

A. This project installs Diesel Particulate Filters at various Distributed Standby Generation (DSG) sites in accordance with the Department of Environmental Quality's Mutual Agreement Order guidance. This project makes it possible for PGE to meet contingency reserve obligations (CRO) by using non-spinning reserves as a result of changes through NERC. This CRO change allows PGE customers to realize a $1.9 million benefit, a value Staff agrees is accurate in Docket UE 436, Staff Exhibit 100. The conditions and requirements of these various sites can vary widely, but it is PGE's goal to ensure that we stay in compliance and avoid fines while making sure that PGE can utilize these resources to meet CRO. To achieve this benefit for customers and meet their energy demand requirements, PGE needs non-spinning resources, and we would have a reduced amount of non-spinning capacity if we do not complete this capital project.

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[14] Staff/3400, Ball/17, at 4-6

[15] Staff/3400, Ball/17-18 at 21-01.

Q. What is PGE's response to Staff's attestation proposal?

A. PGE is generally agreeable to the concept of an officer attestation for a capital project of this size, as this proposal is similar to the proposal that PGE lays out in PGE Exhibit 2400. In accordance with this proposal, there would be one attestation that would occur 45 days after the rate effective date.

IV. Battery Energy Storage Project Adjustments

Q. What proposed adjustments does Staff make to the Constable and Seaside projects in rebuttal testimony?

A. Staff's rebuttal proposal for both the Constable and Seaside battery projects begins with a discussion of Staff's respective $14 million and $44 million reductions on the basis of what Staff identifies to be RFP costs. Staff also states that they have concerns about the RFP process and its competitiveness.[16]

Q. Are there any adjustments that Staff has withdrawn in its testimony?

A. Yes. Staff withdrew their $5 million punitive adjustment. While PGE continues to disagree with the appropriateness and regulatory authority for an adjustment such as the one proposed by Staff as a method to address what is in essence a discovery dispute, we also acknowledge Staff's removal of what they admitted was a punitive adjustment. Staff does note in rebuttal testimony that they "take issue with PGE's statement" that Staff had access to the requested information through its participation in other dockets, and stated they requested the information from PGE in a data request rather than "risk accidental disclosure of highly sensitive information" or "waste PGE and Staff time going back and forth to figure out whether and how Staff would be allowed to use RFP information under multiple MPOs."[17]

We echo Staff's concerns about the need to avoid unintended disclosure of confidential or highly confidential information and think that the language common in Commission protective orders allowing disclosing parties to agree to the use of protected information in different dockets was intended to avoid just such a risk (by limiting copies being shared

[16] Staff/2400, Dlouhy/15-16.
[17] Staff/2400, Dlouhy/14, at 17-19.

numerous times in different venues). If asked, PGE tries to work with parties wanting to use protected information from other dockets and thinks that would have been a better approach by Staff than proposing $5 million in punitive adjustments. PGE has previously offered and continues to offer to Staff the ability to contact us and ask for clarification and guidance about what information should not be disclosed or should only be disclosed under the appropriate protective order.

Q. Did Staff also withdraw their issues regarding the RFP process?

A. No. Despite the data provided by PGE demonstrating that the total number of bids submitted in various PGE RFPs has steadily increased, that there was oversight provided by an Independent Evaluator throughout the RFP process, and Staff's own acknowledgment outside of this docket that the Commission's competitive bidding rules worked as intended in the 2021 RFP[18] in which these BESS projects were selected, Staff continues to express "concerns" regarding the competitiveness of PGE's RFP process.[19]

Q. Does PGE agree with the arguments that Staff makes regarding the RFP process as a whole?

A. No. Staff discusses that the percentage share of benchmark bids present in the final shortlist of RFPs is increasing and uses this statistic to claim that "some portion of the RFP scoring or selection process is skewed to favor PGE's own bids."[20] This assertion lacks foundation in factual evidence or statistically sound analysis. The conclusion drawn from observing a higher percentage of benchmark bids in the final shortlist seems to be based on unsubstantiated speculation rather than a comprehensive evaluation of all potential factors. There are several

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[18] Exhibit 2802 provides Staff's response to UE 427 PGE Data Request No. 28.
[19] Staff/2400, Dlouhy/16
[20] Staff/2400, Dlouhy/16 at 1-3.

alternative explanations that merit consideration. To draw a conclusion of unfairness in the process based solely on the outcome, without considering other potential factors, represents a significant and unsubstantiated logical leap.

Furthermore, the RFP process involves significant feedback by Staff and Stakeholders, and oversight by the Independent Evaluator and Commission. The Commission selects an Independent Evaluator who reviews and evaluates PGE's draft RFP, and ultimately its scoring of all bids. To ensure the Independent Evaluator is able to fully oversee the RFP process, PGE copies the Independent Evaluator on all communications with bidders. Ultimately, the Independent Evaluator, files a report to the Commission on its findings, which includes its analysis of scoring and overall fairness of the process. Additionally, in the 2021 RFP, the Independent Evaluator was required to oversee the negotiation process—this was a condition recommended by Staff and adopted by the Commission when acknowledging PGE's final shortlist.[21] Staff's criticism of this process contradicts the statements from Staff's June 29, 2022 report that recommended acknowledgement of the final shortlist in this RFP that stated "[t]he IE observed that the RFP process was run in accordance with the rules laid out in the RFP document; bidders were treated fairly under the rules of the RFP; offers selected for the final shortlist were selected fairly; and PGE's price and non-price scoring were reasonable."[22]

It is contradictory to state "concern" regarding the scoring or selection process when Staff previously acknowledged that the selection process was fair and PGE's scoring was reasonable.[23] Furthermore, Staff's apparent reversal of position regarding the fairness of the

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[21] *See In the Matter of Portland General Electric Company, 2021 All-Source Request for Proposals*, Docket UM 2166, Order No. 22-315 at 4 (Aug, 31, 2022).
[22] UM 2166, Staff Report at 5 (June 29, 2022).
[23] Staff/2400, Dlouhy/16 at 2.

process overseen by the Independent Evaluator is concerning. Initially, Staff acknowledged that the process was conducted fairly, particularly as it related to the number of benchmark bids. However, to subsequently change this stance during a cost recovery proceeding regarding this issue is a perplexing and inconsistent shift in position. To do so without substantial new evidence or changed circumstances is inappropriate and troubling.

Q. Revisiting Staff's argument regarding the costs included in this rate case for the Constable and Seaside projects, does Staff acknowledge that their initial analysis omitted "key components of the project cost?"[24]

A. No. Staff states that they believe "it is important to ground actual project amounts with those that are presented in the RFP when scoring bids," but then does not observe the project costs included in the price scoring workbooks provided in PGE's response to Staff Data Request Nos. 171 and 173 (DR 171 and 173).[25][26]

When asked in discovery why Staff disagrees that AFUDC and owners costs are contemplated in the RFP, they responded that "all expected costs associated with a utility-owned capital project – including AFUDC and owners' costs – would have been submitted as part of a bid into the RFP."[27] Staff points to the "Carrying Costs" tab on the 2021 RFP price scoring workbook as providing this information, and PGE agrees with this approach to find RFP cost projections.[28] However, this is not the value Staff is relying upon for their adjustment; they are instead looking at only the EPC contract cost. In the event Staff is looking

[24] PGE/1700, Powell-Clark/14 at 5.
[25] Staff/2400, Dlouhy/13 at 11-12.
[26] These price scoring workbooks were provided in PGE's reply testimony as PGE Exhibits 1701 and 1702.
[27] Provided here as PGE Exhibit 2803HC.
[28] To clarify, PGE agrees that comparing costs included for recovery provides a useful comparison but notes that costs can and do change from the RFP to cost recovery, as per OAR 860-089-0500(2) "An electric company must request that the Commission acknowledge the electric company's final shortlist of bids before it may begin negotiations."

at an incorrect cell, PGE Exhibit 2804 provides clear guidance on the DR 171 and 173 cells that align with PGE's request in this proceeding.

Q. Are there any differences between the capital costs in the RFP workbooks and PGE's request in this proceeding?

A. Yes. As stated in PGE Exhibit 1700, footnote 25, the Seaside price scoring workbook in DR 173 does not contemplate the roughly **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** million worth of land cost that is included in gross plant amounts for Seaside. PGE is currently analyzing the customer benefits of buying this land as opposed to leasing it. Additionally, while not yet reflected in gross plant amounts for Seaside, PGE expects this land cost to increase by roughly **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**

Q. Staff references Docket UE 427 (UE 427) as an example where they used a similar approach and stated that PGE expressed no concerns with Staff's approach in that proceeding.[29] Did the costs relied upon by Staff in UE 427 contain AFUDC and Owners Costs?

A. Yes. And we reiterate that when these costs are included in a review of Constable and Seaside, it is clear PGE's request is consistent. **[BEGIN HIGHLY CONFIDENTIAL]** [redacted], **[END HIGHLY CONFIDENTIAL]** which Staff acknowledged.[30]

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[29] Staff/2400, Dlouhy/13-14 at 19-02.
[30] In the Matter of *Portland General Electric Company*, Renewable Resource Automatic Adjustment Clause (Schedule 122) (Clearwater Wind Project), Docket UE 427, Staff/200, Dlouhy/9-10 (Feb 6, 2024) stated that

Q. Does this mean that PGE agrees with Staff's assertion that RFP projects included in prices need to exactly match the RFP modeled amount?[31]

A. No. While we have demonstrated above and within PGE Exhibit 2804 that is not a concern within this proceeding, there may be instances where a higher (or lower) price may be justified. It is only upon the issuance of a final shortlist within an RFP that PGE can begin negotiating with an RFP counterparty. The Commission has recognized that circumstances may change from final shortlist acknowledgement to actual procurement, and addressed this in the 2021 RFP. As the Commission has stated, "acknowledgement of the final shortlist is a finding by the Commission that an electric company's final shortlist of bid responses appears reasonable at the time of acknowledgement, based on what is known or knowable at the time, and was determined in a manner consistent with the resource procurement rules."[32] In acknowledging PGE's final shortlist of projects for the 2021 RFP, while the Commission noted that the final shortlist provides important information about least-cost, least-risk options, the Commission expressly acknowledged that "circumstances may change as PGE's procurement process goes on"[33] and that "PGE's ultimate decisions about resource acquisitions may be different than they were contemplated to be at the time of acknowledgement."[34]

Q. Is there a recent example other than the Seaside land purchase option described above?

A. Yes. Clearwater is a perfect example of this. The costs for Clearwater would have come in below RFP amounts but for the fact that PGE incurred additional costs to secure the Energy

the RFP capital amount was **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL],** while PGE's request was $432 million.

[31] *See* Staff/1700, Dlouhy/20 at 17-18 and Dlouhy/28 at 17-19.

[32] UM 2166, Order No. 22-315 at 3 (Aug, 31, 2022).

[33] Order No. 22-315 at 4.

[34] *Id*.

Community production tax credit benefit for the project. While this increased the capital cost of Clearwater, the customer benefits associated with the additional 10% PTC adder, which is included in forecasted net variable power costs, is expected to deliver additional customer benefit.

Q. What does PGE recommend regarding Staff's battery project adjustments?

A. In light of the discussion above and support PGE has provided in PGE Exhibit 2804, PGE recommends that the Commission reject Staff's $14 million and $44 million adjustments for Constable and Seaside respectively, as they are based on incomplete and faulty analysis. Please see PGE Exhibit 2200 for PGE's position regarding the Constable and Seaside Tracker proposals.

V. Fleet

Q. Please summarize Staff's rebuttal testimony and current proposals relating to PGE's fleet of motor vehicles.

A. In response to PGE's reply testimony, Staff updated their proposals regarding PGE's fleet. Staff's rebuttal testimony on PGE's fleet of motor vehicles proposes two categories of adjustments. The first category of adjustments, for what Staff argues is the premature replacement of vehicles, amounts to an updated reduction of $3.1 million. This updated amount reflects a correction of data used by Staff and continues to be primarily based on their assertion that PGE should not use mileage or age as the sole reason for retirement of a vehicle.[35]

The second category of adjustments is "the net EV premium," which Staff contends are excess amounts PGE spent to electrify certain fleet vehicles instead of buying non-EV alternatives. Two separate "net EV premium" adjustments are proposed by Staff–a reduction for the 2023 year that "originated from Staff's proposed adjustment of $2.4 million for this issue in UE 416 (PGE's 2024 GRC)"[36] plus a $231 thousand reduction related to net EV premium in this proceeding. The latter adjustment reflects an update to Staff's methodology, which applies some O&M savings to all EVs purchased by PGE.

Q. Has Staff withdrawn any of their fleet recommendations from opening testimony?

A. Yes. In rebuttal testimony, Staff withdrew their proposed capital reduction of $120 thousand associated with what they deemed "improper configurations."[37]

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[35] Staff/3200, Shierman/32 at 1-5.
[36] Staff/3200, Shierman/22-23.
[37] Staff/3200, Shierman/32.

Q. Staff believes that age and mileage are not on their own reason enough for PGE to retire a vehicle,[38] how does PGE respond?

A. PGE disagrees with that statement. Vehicles of excessive age and mileage are replaced because they are at a high risk of major component failure. Using state and industry fleet management standards to calculate the age of a vehicle, which includes idle time, the average effective mileage of the vehicles that PGE is replacing is over 190,000 miles, with some reaching 500,000 miles or more. This is important for a couple key reasons.

First, as vehicles age, they become more expensive to maintain, which increases PGE's O&M expense and ultimately customer prices. This is compounded by the fact that as vehicles become older the manufacturers begin to discontinue critical parts, making replacements more expensive, if available at all.

Second, as vehicles become more unreliable, they may break down while in service. Many of these vehicles serve critical needs supporting our grid, correcting outages while customers wait for their service to come back on. Customers rely on these vehicles just as PGE does. Additionally, PGE is liable for these vehicles and damages they may cause – if a vehicle experiences a major failure while in service it could pose serious risks to PGE crews and the general public, which is an unnecessary risk PGE seeks to avoid.

Q. What are fleet management standards for vehicle replacement based on age or mileage?

A. This can vary depending on the source of expertise, and there are many inputs such as the type of vehicle, the use case of the vehicle, and even the climate the vehicle generally operates in. However, the State of Oregon uses a standard of both age and mileage, wherein all vehicles

[38] Staff/3200, Shierman/32 at 1-5.

that reach either eight years or 115,000 miles are to be disposed of.[39] The Oregon Department of Administrative Services describes these disposal criteria as important for "safety, efficiency and cost effectiveness."[40]

Q. Based on age or mileage, would the vehicles PGE plans to dispose of in 2024 meet the State of Oregon's fleet disposal criteria?

A. Yes.

Q. Does Staff propose any alternative standards for determining when to retire a vehicle?

A. No. Staff makes no such proposal.

Q. If PGE is replacing a vehicle because of concerns of critical failure, what further justification could PGE provide?

A. Extending the service life of these vehicles beyond their recommended replacement period poses significant operational and safety risks. Critical failures could occur without warning, potentially resulting in delayed power restoration for customers due to vehicle breakdowns during service calls, PGE crews becoming stranded in adverse weather conditions, and unnecessary safety hazards for both PGE personnel and the general public. The specialized nature of many of these vehicles means replacements can take months to procure, exacerbating the impact of unexpected breakdowns.

Waiting for catastrophic failure, such as an engine or transmission failure that requires a total rebuild or replacement of the system, before replacing vehicles is not a prudent or safe operational strategy. Staff's recommendation to further extend vehicle life appears to disregard these critical safety and reliability concerns. PGE's vehicle replacement policy is designed to

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[39] Department of Administrative Services. "Fleet Policy." Page 6. https://www.oregon.gov/das/Policies/Fleet.pdf

[40] *Id.*

balance cost-effectiveness with the imperative to maintain a safe and reliable fleet. We believe this approach is essential for ensuring consistent service quality and protecting the safety of our employees and the public we serve.

Q. Staff asserts that PGE did not offer support in reply testimony for the inclusion of investments related to the 2023 purchase of EVs included in a black box settlement in UE 416. Is this true?

A. No. PGE supports the inclusion of these expenses in PGE Exhibit 1700, citing the Oregon Governor's Executive Order (EO) 20-04, and the environmental and health benefits these investments endow upon customers.[41]

Q. Are state agencies in Oregon also electrifying their fleets?

A. The State of Oregon's Department of Administrative Services fleet policy requires that state agencies replace ICE vehicles with Zero Emission Vehicles (ZEV), which they define as either plug-in hybrid electric vehicles (PHEV), EVs, or hydrogen powered vehicles "whenever feasible."[42] The policy that went into effect in 2022, and applies to all state-owned vehicles, dictates that "[a]gencies must encourage adoption and active use of ZEVs to reduce carbon based and other greenhouse gas emissions." While this policy applies to governmental agencies and travel by governmental employees, we support the State of Oregon's recognition of the value and importance of fleet electrification.

Q. What else does PGE have to say on the matter?

A. The black box settlement PGE entered into in UE 416 was not an agreement to a permanent disallowance, and the evidence in UE 416 as well as this general rate case demonstrate the

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[41] PGE/1700, Powell-Clark/28 at 2-13.

[42] Department of Administrative Services. "Fleet Policy." Page 6. https://www.oregon.gov/das/Policies/Fleet.pdf

prudence of these investments. Further, the settlement agreement did not specifically tie a value to any of the items included.

Q. Staff rejects PGE's arguments supporting the 2024 purchase of EVs in excess of the expense of comparable ICE vehicles, how does PGE respond?

A. Staff's remaining proposed reduction of $231 thousand relates to $1.8 million in capital investments. These investments are critical for PGE to meet requirements set forward by the State of Oregon, such as the Advanced Clean Trucks (ACT) and the Advanced Clean Fleet (ACF) rules. Furthermore, PGE is invested in the future, and the future rests in EVs. Staff's proposed reduction discourages PGE's investment in EVs, and therefore discourages PGE's investment in the reduction of greenhouse gases, long-term O&M savings, vehicles capable of meeting noise ordinances, and displays a lack of knowledge and proper understanding of the application of these vehicles. Additionally, as PGE notes above, the purchase of these vehicles aligns with the state's own fleet policies.

Q. Staff's basis for adjustments related to "net EV premium" seem to suggest that PGE is not appropriately considering the cost of electrifying its fleet. Is this true?

A. No. PGE is performing constant analysis of our fleet electrification goals to ensure that the necessary and prudent transition is performed at the least cost possible. In fact, PGE has recently updated our goals in this area pushing our transition to an electrified fleet back some years. With the exception of PGE's forklifts, the goals for the electrification of all categories of vehicles have been updated to reflect lower adoption across longer timeframes. For example, PGE's original goal for light duty vehicles such as passenger cars was 100% EV adoption by the 2025 year, but due to economic considerations PGE has updated these goals, instead calling for 38% percent EV adoption within its fleet of light duty vehicles by the 2025 year and increasing the timeframe so that this category will not reach 100% adoption until 2043. This lengthened timeframe will allow PGE to utilize currently owned ICE vehicles in its fleet until those vehicles reach an end-lifecycle state, rather than replacing ICE vehicles simply to reach EV related goals. PGE's long-term fleet plans are a reflection of its careful consideration of costs weighed against the long-term benefits of EV adoption.

Q. Please summarize PGE's position on Fleet of Vehicles.

A. PGE respectfully requests that the Commission reject Staff's proposed rate base reductions related to fleet vehicles. We contend that Staff's proposals fail to account for the necessary and prudent disposal of aging vehicles that pose increasing operational risks. Furthermore, they do not adequately recognize the value that electric vehicles bring to PGE's customers in terms of operational efficiency and environmental benefits. Additionally, we believe these proposals are inconsistent with state policies promoting the adoption of electric vehicles and the reduction of carbon emissions in fleet operations. We urge the Commission to consider the long-term safety, reliability, and environmental implications of maintaining an appropriately modernized fleet in its decision-making process.

VI. Associated Energy Storage

Q. What is Staff's recommendation on the topic of the RAAC and Associated Energy Storage?

A. Staff "believes that the record on this topic is complete and recommends that the Commission rule on 'associated storage' in this docket."[43]

Q. Does PGE agree that the record is complete?

A. No, especially since PGE dropped this issue within UE 435 as stated in PGE Exhibit 1700. Should the Commission want to address the issue within this docket, PGE now provides Exhibit 2805, which provides the UE 416 testimony and exhibits on the topic.

[43] Staff/2400, Dlouhy/4 at 9-10.

VII. Qualifications

Q. Kori Mead, please summarize your qualifications.

A. I received my Master of Science in Accounting from the University of Oregon and received my Certified Public Accountant license from the Oregon Board of Accountancy. I joined PGE as an Accountant in September 2015, and have been a Senior Energy Supply Procurement Originator since November 2020.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
2801	UE 416 PGE Production Testimony
2802	Staff Response to UE 427 PGE Data Request No. 28
2803HC	Staff Response to PGE Data Request No. 24
2804	How To Read RFP Price Scoring Worksheets
2805	UE 416 Associated Energy Storage Testimony

UE 435

Exhibit 2801 has been retained in its native format

Date: August 12, 2024

TO: Portland General Electric Company

From:
JP Batmale
Administrator
Energy Resources and Planning
jp.batmale@puc.oregon.gov

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 427 – PGE's Data Request No. 28

Data Request No. 28:

Please provide a narrative description of any conversation between JP Batmale and Jake Stephens on or after March 1, 2024.

Staff Response No. 28:

I have had only one conversation with Jake Stephens on or after on March 1, 2024. On March 6, 2024, I returned Jake's call from March 5. Based on the screen shot from iPhone, the call began at 7:47am and lasted 47 minutes. We spoke about New Sun's perception of events around the benchmark bid project in UM 2166 and the project's prudency review in UE 427. Specifically, Mr. Stephens was adamant that the Independent Evaluator and the approach to both the transmission requirements and bid evaluation in UM 2166 were all a failure. I remember disagreeing with Mr. Stephens about each of these issues and making the case that not only had the PUC competitive bidding rule processes worked as intended, but that the release of the final report in UM 2166 and the discussion being had about the Clearwater project in UE 427 were additional evidence that the PUC was in fact operating at a high level of transparency and in the public interest despite his characterizations.

UE 435

Exhibit 2803 is HIGHLY CONFIDNETIAL pursuant to Modified Protective Order No. 24-062

<u>Constable:</u>

For an accurate look at what RFP cost should be used in Staff's analysis, they should have used the Price Scoring workbook as provided in response to Staff Data Request No. 171-A. This workbook is from after the price scoring update on August 26, 2022, and has the last and most recent Constable price contemplated by the RFP.

By choosing partial bid #5, and looking at the "Carrying Costs" tab, cells W-Y3 have the amounts that were contemplated in the price scoring of the RFP for Constable. To see a concise breakout of EPC costs, owners costs, and AFUDC, please see the table on the "Assump" tab, beginning in cell C119.

<u>Seaside:</u>

For an accurate look at what RFP cost should be used in Staff's analysis, they should have used the Price Scoring workbook as provided in response to Staff Data Request No. 173-A. This Price Scoring workbook contemplates Seaside with the full 200 MW of capacity.

By choosing partial bid #8, and looking at the "Carrying Costs" tab, cells W-Y3 have the amounts that were contemplated in the price scoring of the RFP for Constable. To see a concise breakout of EPC costs, owners costs, and AFUDC, please see the table on the "Assump" tab, beginning in cell C119. As a reminder, Seaside land cost is not included in this RFP workbook, as explained in PGE Exhibit 2800, page 16.

UE 435

Exhibit 2805 has been retained in its native format

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 435

Cost of Capital

PORTLAND GENERAL ELECTRIC COMPANY

Surrebuttal Testimony of

Josh Figueroa
Christopher Liddle

October 1, 2024

Table of Contents

I. Introduction and Summary

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

A. My name is Josh Figueroa (he/him/his), and I am a Senior Associate of The Brattle Group, whose business address is One Beacon Street, Suite 2600, Boston, Massachusetts, 02108. I provided direct testimony in Section IV of PGE Exhibit 600 and Section III of PGE Exhibit 1800. My qualifications can be found in PGE Exhibit 603.

My name is Christopher A. Liddle. I am the Senior Director, Risk Management and Assistant Treasurer at PGE. My qualifications can be found at the end of PGE Exhibit 600.

Q. What is the purpose of your testimony?

A. Our testimony responds to rebuttal testimony submitted by parties to this proceeding regarding return on equity, weighted cost of debt, and capital structure.

Mr. Figueroa will continue to support PGE's position that a higher return on equity (ROE) than currently authorized is warranted given existing market dynamics, though PGE reduced its proposal from 9.75% to 9.65% within its reply testimony submitted on August 14, 2024.

Mr. Liddle will address Staff (Staff) of the Public Utility Commission of Oregon (OPUC) and the Alliance of Western Electric Consumer (AWEC) testimony regarding PGE's capital structure and Staff's testimony on PGE's cost of long-term debt.

II. Return on Equity

A. Introduction

Q. Mr. Figueroa, what is the purpose of your testimony in this proceeding?

A. I have been asked to review and comment on the rebuttal testimony of Mr. Matt Muldoon of the Staff of the OPUC as it pertains to the ROE for Portland General Electric Company (PGE or the Company). I have also been asked to respond to the rebuttal testimony of Mr. Lance D. Kaufman on behalf of AWEC; the rebuttal testimony of Lisa V. Perry on behalf of Walmart Inc. (Walmart); and Mr. Bob Jenks on behalf of the Citizen's Utility Board (CUB) (collectively, the Parties) as each of these testimonies pertain to the allowed ROE for PGE.

Q. Is there anything in Staff's or the Parties' rebuttal testimony that caused you to change your recommendations regarding PGE's return on equity?

A. No. Having reviewed the rebuttal testimony of Staff and AWEC, I continue to find that the Company's requested allowed ROE of 9.65% on a 50% equity capital structure remains reasonable and conservative given my recommended ROE range of 10.25% to 11.25%.[1] PGE is requesting an ROE below my recommended range in an effort to work collaboratively with stakeholders, address affordability concerns, and narrow issues in this proceeding.[2]

Q. Please summarize your testimony.

A. Having reviewed the rebuttal testimony of Staff and AWEC, I find the following:

- Staff increased its recommended ROE range by 5 to 26 basis points to 9.22% to 9.46%, however its recommended ROE range is still too low.[3] This is due to several flaws in Staff's implementation of its Discounted Cash Flow (DCF) models and

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[1] PGE/1800, Figueroa - Liddle/6-7.
[2] *Id.* 3.
[3] Staff/2800, Muldoon/9.

Capital Asset Pricing Models (CAPM) that I raised in my reply testimony and are still present in Staff's revised models.[4] AWEC maintained its recommended ROE of 9.25%, which I continue to find to be too low due to flaws in the ROE methodology.[5] Both Staff and AWEC's ROE recommendations remain well below recently allowed ROEs for vertically integrated electric utilities, which further indicates the unreasonableness of their recommendations.

- Staff takes issue with my sample selection criteria to exclude potential proxy utilities based on recent Mergers & Acquisition (M&A) activity and dividend cuts. Staff's arguments are premised on a misunderstanding of my testimony and how these screening criteria are applied.
- Staff and AWEC continue to argue in favor of using the geometric mean to estimate the Market Equity Risk Premium (MRP). These arguments go against a large body of academic articles and practitioner texts that say it is arithmetic mean that is relevant when estimating the cost of equity and the geometric mean when measuring investment portfolio performance.[6] Further, the use of the geometric mean is always lower than the arithmetic mean and thus downwardly biases Staff's and AWEC's CAPM estimates.
- AWEC argues in favor of the Kroll normalized MRP by saying it is an unfounded assumption that there is a constant, fixed linear relationship between interest rates and the MRP. However, this ignores well-established academic research that shows there is an inverse relationship between the MRP and interest rates. I continue to find

[4] PGE/1800, Figueroa – Liddle/ Section III.C.
[5] AWEC/400, Kaufman/24.
[6] PGE/1800, Figueroa - Liddle/34-35, 42-43.

that Kroll's normalized MRP is inconsistent with this relationship and therefore should not be given any consideration.

- AWEC argues their industry betas are consistent with methodologies discussed in academic research. However, the studies cited rely on different beta weighting methodologies, supporting my conclusion that AWEC's adjustment methodology is non-standard. Further, the sources cited by AWEC to support their methodology as superior to the Blume adjustment explicitly caution against their general applicability and other academic sources find that the standard application of AWEC's adjustment methodology performs no better than the Blume adjustment, which Staff and I rely on.
- Staff makes an incoherent argument that using earnings growth rates rather than dividend growth rate in the CAPM is double counting. Assuming this argument is about the DCF model, which relies on dividend growth rates as an input, I continue to find that relying on dividend growth rates does not reflect the fact that all earnings belong to shareholders and that there are ways other than dividends that the companies can use to return cash to investors.
- Despite updating its analysis, Staff's Hamada adjustment contains serious flaws because it relies on book capital structures, rather than market value capital structures in its calculation. Financial economics is clear that it is market value capital structure that is relevant when accounting for differences in financial risk.

Q. Please summarize the ROE and capital structures recommendations put forth in this proceeding.

A. Figure 1, below, summarizes the ROE and capital structure recommendations put forth in this proceeding, including Staff's updated recommended range.[7]

Figure 1: Recommended ROE and Reasonable Ranges

Party	Recommended ROE	Low Range	High Range	Recommended Equity %
PGE/Figueroa[8]	**9.65%**	**10.25%**	**11.25%**	**50.0%**
OPUC Staff Rebuttal[9]	n/a	9.22%	9.46%	50.0%
OPUC Staff Direct[10]	n/a	8.96%	9.41%	50.0%
Kaufman (AWEC)[11]	9.25%	7.6%	9.3%	44.6%
Jenks (CUB)[12]	9.2%	9.2%	9.4%	n/a
Perry (Walmart)[13]	n/a	n/a	n/a	n/a

B. Response to Staff and AWEC

Q. In rebuttal testimony, Staff and AWEC argue that their respective ROE recommendation for PGE is reasonable. Do you agree?

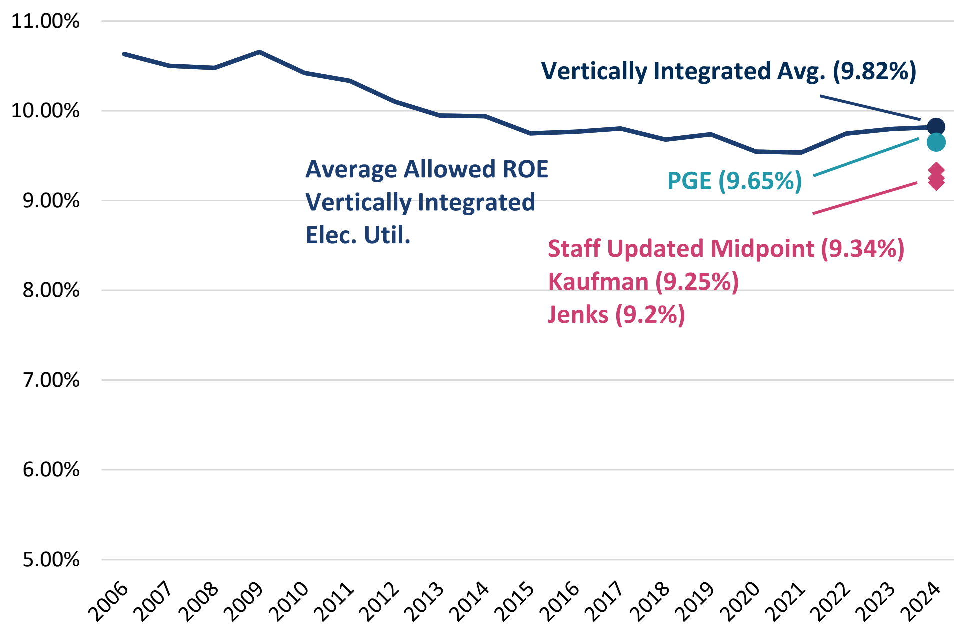
A. No. I continue to find that Staff's revised recommended ROE range of 9.22% to 9.46% and AWEC's recommended ROE of 9.25% are too low, not reflective of market indicators or recently allowed returns for other vertically integrated electric utilities, and are derived from problematic ROE estimation methodologies.[14]

Staff argues that PGE's requested ROE of 9.65% is a "sizable increase" from its current authorized ROE of 9.5% and instead the Commission should authorize an ROE within its

[7] *Note*, Staff provided a recommended range of ROEs for PGE but did not recommend a point estimate. *See* Staff/2800, Muldoon/34.
[8] PGE/1800, Figueroa – Liddle/17. *Note*, in the Figueroa-Liddle Testimony, the Company requested an allowed ROE of 9.75% but has since made a managerial decision to reduce the Company's requested allowed ROE to 9.65%.
[9] Staff/2800, Muldoon/34.
[10] Staff/2800, Muldoon/5, 7.
[11] AWEC/400, Kaufman/75.
[12] CUB/400, Jenks/70-71.
[13] *Note*, Walmart does not offer a specific ROE or capital structure recommendation. *See* Walmart/100, Perry/13-14.
[14] I also continue to find CUB's recommended ROEs is too low as well.

revised range, which it finds is consistent with other utilities with commensurate risks.[15] Yet, Staff's own evidence suggests otherwise. Staff cites a Regulatory Research Associates (RRA) article from July 2024 that shows the average authorized ROE for *electric* utilities so far this year is 9.68%.[16] Staff fails to mention that the RRA article reports the year-to-date average authorized ROE for *vertically integrated* electric utilities was 9.74% in the first half of 2024.[17] Furthermore, RRA's Past Rate Case database indicates that the average allowed ROE for vertically integrated electric utilities has further increased to 9.82% as of September 16, 2024.[18] Staff's revised estimates are 36 to 60 basis points below the current average authorized ROE for other vertically integrated electric utilities with commensurate risks.

Figure 2: Allowed ROE for Electric Utilities versus Staff's And Parties' ROE Recommendations



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[15] Staff/2800, Muldoon/10, 24.
[16] *Id*. 24.
[17] Staff/2812, Muldoon/4.
[18] PGE Exhibit 2901C.

AWEC similarly argues that PGE's requested ROE of 9.65% is too high and recommends that the Commission authorize an ROE at the lower range of recently authorized ROEs.[19] AWEC's argument is not supported—no research or analysis is offered to support AWEC's claim that authorizing an ROE at the lower end of the range of recently allowed as justified or providing a fair risk-adjusted return.[20] In my Direct Testimony, I discuss at length that PGE faces higher business risks due to wildfires, its Power Cost Adjustment Mechanism, Oregon's clean energy and climate goals, and its smaller size.[21] AWEC's recommended ROE of 9.25% is simply too low and no weight should be given to its baseless assertion that PGE should be awarded an ROE at the lower end of recently allowed ROEs.

Q. The Federal Reserve cut the Federal Funds Rate by 50 basis points on September 18, 2024.[22] What are the implications for interest rates and the investor-required return on equity?

A. The Federal Reserve cut the Federal Funds Rate by 50 basis points in light of recent downward trends in inflation (notably, the latest inflation reading was 2.5%,[23] which is still above the Federal Reserve's target of 2% on average).[24] The Federal Reserve indicated that additional rate cuts may come depending on future trends in economic conditions. However, the Federal Open Market Committee (FOMC) was clear in saying that "these projections, however, are

[19] AWEC/400, Kaufman/25.
[20] AWEC/400, Kaufman/25.
[21] PGE/600, Figueroa – Liddle/51.
[22] Federal Reserve, "Federal Reserve issues FOMC Statement," September 18, 2024, https://www.federalreserve.gov/newsevents/pressreleases/monetary20240918a.htm.
[23] US Bureau of Labor Statistics, Consumer Price Index News Release, USDL-24-1864, September 11, 2024, https://www.bls.gov/news.release/archives/cpi_09112024.htm.
[24] Federal Reserve, "Transcript of Chair Powell's Press Conference," September 18, 2024, p. 2, https://www.federalreserve.gov/mediacenter/files/FOMCpresconf20240918.pdf.

not a Committee plan or decision."[25] That is to say, the pace and extent of future change to monetary policy is not known.

Since the time of the announcement, yields on long-dated government bonds have increased somewhat. The yield on 10-year U.S. Treasuries increased from 3.65% on September 17 (the day prior to the announcement) to approximately 3.79% currently.[26] Similarly, the yield on 20-year U.S. Treasury increased from 4.02% to 4.18% over the same time period.[27] The current yields are at nearly the same level as they were at the time I performed my cost of equity analysis (3.88% yield on 10-year U.S. Treasuries and 4.20% yield on 20-year U.S. Treasuries).[28] It is the changes in yields for these longer-dated government bonds that are most relevant for estimating the cost of equity for PGE and the market's reaction since the rate cut has been to keep rates at or near recent levels. However, to the extent that interest rates decline going forward, it is important to recognize that PGE's requested allowed ROE is already lower than my reasonable range, as well as Staff's and AWEC's reasonable range after correcting for various shortcomings in their methodologies.

C. Proxy Sample

Q. What are Staff's criticisms of your proxy sample selection criteria?

A. Staff recognizes that there is significant overlap between Staff's proxy sample and my proxy sample, but takes issue with the screening criteria I relied upon to derive the sample,[29] specifically, how companies are excluded based on M&A activity and dividends. Staff argues

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[25] *Id.*, p. 4.
[26] FRED, "Market Yield on U.S. Treasury Securities at 10-Year Constant Maturity," DGS10, accessed September 26, 2024.
[27] FRED, "Market Yield on U.S. Treasury Securities at 20-Year Constant Maturity," DGS20, accessed September 26, 2024.
[28] FRED, "Market Yield on U.S. Treasury Securities at 10-Year Constant Maturity," DGS10 and "Market Yield on U.S. Treasury Securities at 20-Year Constant Maturity," DGS20, as of December 29, 2023.
[29] Staff/2800, Muldoon/12-15.

that looking back six months for completed or terminated transactions is problematic because not all mergers are considered "successful" and then lists eight non-utility merger examples.[30] Staff also argues this is problematic because some transactions are terminated for which Staff uses the Hydro One and Avista merger as an example.[31]

Staff argues that proxy companies should have no recent major M&A activity and no cuts in dividends in the prior five years.[32] They point to recent PGE statements to investors indicating that the company is financially sound with predictable income and not entertaining a buyout of the Company.[33]

Q. How do you respond to Staff's criticisms of your proxy sample selection criteria?

A. Staff and I both screen out potential proxy companies based on recent M&A activity and dividend cuts. These screens are important because they can impact a company's stock price or other financial indicators that are not representative of how investors typically perceive the company's business and financial risk characteristics.[34]

However, Staff misinterprets my testimony and incorrectly states that I am only concerned with M&A transactions that occurred in the past six months.[35] As I state in my Direct Testimony, I look back five years for pending M&A transactions and six months back for completed or terminated transactions.[36] Further, Staff argues my criteria is problematic because not all mergers are successful.[37] This argument is vague and not supported. To the extent that an M&A transaction is not considered "successful" because it is terminated—like

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[30] *Id.* 14.
[31] *Ibid*.
[32] *Id.* 11.
[33] *Id.* 15.
[34] PGE/600, Figueroa – Liddle/34-35.
[35] Staff/2800, Muldoon/14.
[36] PGE/600, Figueroa – Liddle/35.
[37] Staff/2800, Muldoon 14.

the Avista example from 2019 offered by Staff—then the potential proxy company would be excluded for a period of time following the termination announcement.[38] Or, if Staff means that the transaction underperforms financial expectations, as some of its non-utility M&A examples might suggest, then this would be reflected in its stock price, growth expectations, or other financial metrics that are relied upon to derive an ROE estimate. Staff offers no framework for how to screen out proxy companies based on the "success" of their M&A transaction, nor do they offer any reasoning as to why my M&A screening criteria are not adequate in this respect.

Further, I exclude potential proxy companies that had dividend cuts in the past six months. In my opinion, this allows sufficient time for a utility's stock to adjust following such an announcement and reflect investors' expectations regarding the proxy company. While I generally agree with Staff that utilities with recent dividend cuts should be excluded from the proxy sample, I find Staff's five-year lookback is too restrictive and potentially excludes utilities whose financial metrics have normalized since the time of its dividend cut.

Q. Staff argues that if it were to adopt your sample selection criteria recommendations, PGE's authorized ROE would be reduced.[39] Do you agree?

A. No. As discussed at length in my reply testimony, there are several issues with Staff's ROE methodology, including delayed dividends in the DCF, ignoring other ways that companies return cash to investors, a downwardly biased estimate of the MRP, and not using forecasted-risk free rates, amongst others. Simply addressing the issues with Staff's sample selection criteria is not sufficient and still results in a downwardly biased ROE result.[40] I found in my

[38] Notably, Staff includes Avista in its proxy sample in this proceeding. *See* Staff/2800, Muldoon 17.
[39] Staff/2800, Muldoon/13.
[40] PGE/1800, Figueroa – Liddle/7-8.

reply testimony that making several reasonable adjustments to Staff's ROE analysis to correct for these various shortcomings increases Staff's ROE range by 40 to 220 basis points and, after doing so, is supportive of PGE's requested ROE of 9.65%.[41]

Q. In reply testimony, you criticized Staff for screening out proxy companies with betas greater than 1.0.[42] Did Staff make an adjustment to this screening criterion in its revised ROE analysis?

A. Yes, in its revised ROE analysis, Staff did not exclude proxy companies with betas greater than 1.0 because it argues that recent investments in data centers and artificial intelligence technology has caused new, more speculative investors to invest in utilities, which has increased electric utility stock volatility.[43] As a result, additional utilities were included in Staff's revised ROE analysis.[44] While I agree with Staff that it is appropriate to include utilities with betas greater than 1.0, I disagree that the inclusion of such proxy companies should be premised on investment activity in data centers or artificial intelligence. As I discussed in reply testimony, Staff offered no evidence or analysis to support that utility betas cannot be greater than 1.0 and, in such instances, that would make them poor comparators to estimate the cost of equity.[45] I continue to find it appropriate to consider such companies as potential proxy companies to estimate the allowed ROE for PGE.

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[41] *Id.* 27, 49.
[42] *Id.* 16.
[43] Staff/2800, Muldoon/16.
[44] *Ibid*.
[45] PGE/1800, Figueroa – Liddle/16-17.

D. Capital Asset Pricing Model

Q. What arguments does Staff raise regarding the use of the geometric mean to calculate the market equity risk premium?

A. Staff argues that it is appropriate to use the geometric mean because the Commission has established a precedent of using the geometric mean rather than the arithmetic mean to calculate MRP, citing Commission orders from 1987 and 1994.[46] Staff goes on to argue that failure to apply Oregon precedent inflates my ROE modeling results.[47]

Q. How do you respond?

A. As an independent expert, I find it important to provide the Commission with the best available information to inform its decision of the allowed ROE for PGE. In my reply testimony, I argue that it is appropriate to use geometric means when evaluating the historic performance of a stock portfolio but it is more important to use the *arithmetic* mean when estimating the cost of capital, which is a forward-looking concept.[48] This is well supported in academic and practitioner textbooks, which consistently state that it is incorrect to use the geometric mean when computing the cost of capital.[49] Notably, Staff does not refute the academic evidence that I presented on this matter. As another point of academic evidence on this matter, Bodie, Kane, and Marcus say the following in their practitioner textbook on investments:

> *Which is the superior measure of investment performance, the arithmetic average or the geometric average? The geometric average has considerable appeal because it represents the constant rate of return we would have needed to earn in each year to match actual performance over some past investment period. It is an excellent measure of <u>past</u> performance. However, if our focus is*

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[46] Staff/2800, Muldoon/21-22, referencing OPUC Docket UT 43 Order 87–406 PAC NW Bell (March 31, 1987), and OPUC Docket UT 113 Order 94-336 GTE NW (February 22, 1994).
[47] *Id.* 22-23.
[48] PGE/1800, Figueroa – Liddle/34-35.
[49] *Ibid*.

> *on future performance, then the arithmetic average is the statistic of interest because it is an unbiased estimate of the portfolio's expected return (assuming, of course, that the expected return does not change over time). In contrast, because the geometric return over a sample period is always less than the arithmetic return, it constitutes a downward-biased estimator of the stock's expected return in any future year.*[50]

Given that the cost of capital is a forward-looking concept, it is quite clear from the above quote and other academic sources that the arithmetic mean is the appropriate methodology for estimating the MRP and, not only is the geometric mean the wrong methodology, but it also downwardly biases the cost of equity estimates.

Q. AWEC states that Dr. Ibbotson's 2011 article you cite in your reply testimony supports the use of a geometric mean for estimating the historic MRP.[51] Do you agree?

A. No, AWEC selectively chooses a quote from Dr. Ibbotson's article as its sole point of rebuttal to my critique of AWEC's use of geometric means to estimate the MRP. The article draws a distinction that the MRP (or equity risk premium, ERP, as it calls it) can be estimated and used for different purposes. Dr. Ibbotson states that to *investors* the MRP is "the expected return that investors can earn on stocks in excess of bonds."[52] Dr. Ibbotson goes on in the next sentence to draw a distinction of *corporation's* view of the MRP: "from a corporation's perspective, however, the ERP is part of the cost of equity capital."[53] In its testimony, AWEC selectively quotes the portion of Dr. Ibbotson's article that is referencing the *investor's* perspective (*i.e.*, the expected returns) and leaves out the quote about the *corporation's* perspective (*i.e.,* the cost of equity capital). The full quote from the article is:

> *Investors typically use the Larger Company Stock geometric mean return minus the Long-Term Government Bond return as their characterization of the*

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[50] Zvi Bodie, Alex Kane, Alan Marcus, *Investments*, McGraw-Hill Irwin Publishing. Emphasis in original.
[51] AWEC/400, Kaufman/27.
[52] Roger G. Ibbotson, "The Equity Risk Premium," published in Rethinking the Equity Risk Premium, Research Foundation of CFA Institute, December 2011, at 18.
[53] *Ibid*.

> *historical ERP, which for 1926-2010 is 4.4 percent. In corporate finance and in valuation discounting, arithmetic means are more often used.*[54]

This distinction is entirely consistent with the findings of Dr. Morin (which I quote in Reply Testimony):

> *In capital markets, where returns are a probability distribution, the answer that takes account of uncertainty, the arithmetic mean, is the correct one for estimating discount rates and the cost of capital. While the geometric mean is appropriate when measuring performance over a long time period, it is incorrect when estimating a risk premium to compute the cost of capital.*[55]

AWEC is incorrect that Dr. Ibbotson's article supports the use of the geometric mean. The Dr. Ibbotson article is also consistent with Dr. Morin's and Drs. Brealey, Myers, and Allen's textbooks which clearly state that the arithmetic average is the appropriate methodology when estimating the MRP.[56]

Q. AWEC continues to support Kroll's normalized MRP and argues that it is incorrect to assume a fixed linear relationship between interest rates and the ERP.[57] How do you respond?

A. AWEC argues that it is an unfounded assumption that there is a constant, fixed linear relationship between interest rates and the MRP. However, AWEC ignores the well-established academic research since at least the 1980s that has consistently found an inverse relationship between risk premiums and interest rates, which I cite in my reply testimony.[58] AWEC offers no evidence to support its assertion that this inverse relationship does not exist or the determinants of the MRP have somehow changed over time in such a way that support Kroll's normalized risk-free rate and normalized MRP moving in the same direction.

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[54] *Id.* 20. Emphasis added.
[55] Roger A. Morin, *New Regulatory Finance*, at 151. See also PGE/1800, Figueroa – Liddle/34-35. (emphasis added).
[56] *See* PGE/1800, Figueroa – Liddle/35.
[57] AWEC/400, Kaufman/26.
[58] PGE/1800, Figueroa – Liddle/46-47.

This inverse relationship between the MRP and interest rates was recently affirmed in a Federal Reserve study in 2015 authored by Duarte and Rosa.[59] The authors evaluated the MRP over time using twenty different models used by practitioners and academics and found that the MRP, at the time, was high because Treasury yields were low and that other non-interest rate factors (*e.g.*, future dividend and earnings growth) did not play a significant role in setting the level of the MRP.[60]

I continue to find that Kroll's normalized MRP is problematic because it is not reflective of this well-established inverse relationship between risk premiums and interest rates and should therefore not be considered.

Q. AWEC argues that utility stocks do not converge to 1.0 and therefore does not support the Blume Adjustment.[61] How do you respond?

A. AWEC's argument is premised on a flawed understanding of the Blume adjustment. In his 1971 paper, Dr. Blume made empirical observations that historical measurements of a company's beta are not the best predictors of what the company's systematic risk will be going forward.[62] Dr. Blume was able to apply a consistent adjustment methodology to historical betas that increased their accuracy in forecasting eventual, realized betas. He transformed the historical beta into a "true" beta that is a better predictor of expected future returns using the CAPM. It is important to note that Dr. Blume did not adjust betas for convergence towards 1.0, but rather made an adjustment for sampling errors. When estimating a company's beta using historical market data, there is some sampling error caused by noise in the data and

[59] Fernando Duarte and Carlo Rosa, "The Equity Risk Premium: A Review of Models," FRBNY Economic Policy Review, December 2015, https://www.newyorkfed.org/research/epr/2015/2015_epr_equity-risk-premium.
[60] *Id.* 40.
[61] AWEC/400, Kaufman/31 (emphasis added).
[62] Blume, M. E. (1971), "On the Assessment of Risk," *Journal of Finance*, 26, pp. 1-10.

estimation process. Since the market-weighted average beta for the market is, by definition, 1.0 and repeated measurement indicates that betas for all assets are clustered between 0.5 and 1.5, a particularly high or low estimate of beta is more likely to reflect a sampling (measurement) error rather than an accurate measurement of a company's systematic risk.

To develop a methodology to account for this sampling error, Professor Blume performed a linear regression analysis comparing betas measured in one time period to betas measured in a subsequent period. He found that first-period betas were not good predictors of subsequent period betas. However, he found subsequent period betas were better predicted by taking a weighted average of the first period betas and the market-average beta of 1.0. His regression analysis suggested a weight of 2/3 for first-period betas and 1/3 for the market beta.

Thus, the premise that a utility beta must converge to 1.0 for the Blume adjustment to be applicable is false.

Q. AWEC argues that its industry beta methodology is consistent with the approach outlined in Krysanowski and Jalilvand (1986).[63] What concerns do you have with this argument?

A. AWEC appears to rely on the methodology in Krysanowski and Jalilvand to derive its industry beta. However, if AWEC is supportive of this methodology, it is not clear why it made seemingly arbitrary decisions to divert from this methodology. For example, Krysanowski and Jalilvand weights the industry beta and ordinary least squares ("OLS") by 50% each.[64] Yet AWEC relied on different weights of 66% OLS beta and 34% industry beta, which are the weights used in the Blume Adjustment methodology.[65] Putting aside the merits of industry

[63] AWEC/400, Kaufman/28-30.
[64] *Id.* 30.
[65] *Ibid*.

betas, AWEC's choice of weights is non-standard and calls into question the reasonableness of its beta methodology.

Further, AWEC's conclusion that Krysanowski and Jalilvand supports that its methodology produces superior beta estimates is called into question by the study's authors. Specifically, the authors of the study caution against the general applicability of the paper's findings:

> *It is important to emphasize that the inferences made in this paper about the simple (and statistical) rankings of various beta predictors have only been established with respect to the studied sample, sample period and the MSE measure of forecast accuracy and thus may not be generalizable to other samples of securities, other time periods, and other measures of forecast accuracy.*[66]

Q. AWEC argues that Krysanowski and Jalilvand (1986) supports that industry betas are superior predictors of systematic risk than Blume adjusted betas. Is there academic evidence that says otherwise?

A. Yes, Dimson and Marsh (1983) estimated the stability of various beta measures of companies in the UK over a 25-year analysis period.[67] The authors investigated various beta adjustment methodologies including the Bayesian approach—which is like the approach relied on by AWEC—and Blume adjusted betas. The study found that while Bayesian adjusted betas did improve the predictive power of betas, they did not perform better than Blume adjusted betas, as shown with the similar total mean squared error (MSE) in Figure 3.

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[66] AWEC/402, Kaufman/24.
[67] Dimson, E. and P.R. Marsh, (1983), The Stability of UK Risk Measures and The Problem of Thin Trading. *Journal of Finance*.

Figure 3: Reproduction of Dimson and Marsh (1983) Table IX[68]

Table IX

Stability of Share Betas Estimated in Successive Periods Using Alternative TT Estimation Methods[a]

Panel	Method	Average Correlation between Estimates in Successive Periods	Average MSE in Predicing Beta Estimates: Bias	Inefficiency	Random Error	Total MSE
Panel A	Beta equals historical mean	na	.01	.00	.16	.16
	Trade-to-trade (TT) (Equation 7))	.47	.01	.04	.12	.17
	As above, Bayesian adjustment (Equation (12))	.45	.01	.00	.12	.13
Panel B	Blume adjustment (Equation (11))	.47*	.01*	.01*	.10*	.12*
	Bayesian adjustment (Equation (12))	.46*	.00*	.00*	.10*	.11*
Panel C	TT weighted by cross-sectional variance of residual returns	.48	.01	.04	.12	.17
	As above, Bayesian adjusted	.46	.01	.00	.12	.13

[a] All of these average correlation coefficients and mean squared errors (MSE) were estimated using the same sample and over the same set of time periods as in Tables I–VI above. Asterisked results indicated that the averages are based on predictions for Periods 3, 4, and 5 only. This facilitates comparison between the Bayesian and Blume adjustments. Using the latter, no predictions are available for Periods 1 or 2, because of the need for two start-up periods.

Q. AWEC also cites Gombola and Kahl (1990) to support its utility industry beta of 0.7.[69] **What are your concerns with this argument?**

A. AWEC cites Gombola and Kahl, in part, to support its industry beta of 0.7,[70] but it is important to note that this study calculates an underlying beta for a single stock—Consolidated Edison—from 1970 to 1984 during which the company had a dividend omission.[71] It is unlike that a beta estimate estimated from a single stock almost 40 years ago is representative of a true beta industry beta and let alone applicable for estimating the ROE for PGE today. Further, Consolidated Edison is a unique utility operating in a unique state that may not be comparable to PGE.

[68] *Id.* 776. Red box added for emphasis.
[69] AWEC/400, Kaufman/31-32.
[70] *Id.* 31.
[71] AWEC/402. Gombola, M. J., & Kahl, D. R. (1990). Time-series processes of utility betas: implications for forecasting systematic risk. Financial Management, p. 89.

The issue with industry betas is that it requires an estimate of the "true" beta for the industry, which is not known. AWEC argues the true beta, or underlying mean beta, is 0.7. As discussed in my reply testimony, AWEC's true beta estimate is problematic because it is derived from five-year monthly betas for *just* the proxy sample over the past 10 years.[72] AWEC has provided no evidence to support that this proxy sample beta is representative of the "true" industry beta nor that the last 10 years is indicative of the "true" industry beta.

Q. Has AWEC provided any evidence that industry adjusted betas have been accepted and used in setting the allowed ROE for regulated utilities?

A. No. As discussed in my reply testimony, Blume adjusted betas are commonly relied upon in regulatory settings, including in Oregon, Michigan, Illinois, Montana, and North Carolina.[73] However, AWEC offers no examples of regulatory commissions that have relied on industry betas to set the allowed ROE for a utility. AWEC's industry betas are highly problematic and non-standard and should not be considered.

Q. Staff appears to imply that you are data shopping to "look at beta calculations from a variety of different sources, each with a different method for calculating reversions to a mean over time and other factors" whereas Staff relies on standard data sources.[74] Is this true?

A. No, Staff's assertions are simply wrong and unfounded. I consistently rely on *Value Line* betas in my CAPM analyses.[75] Notably, this is the same data source that Staff relies upon for its beta estimates.[76]

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[72] PGE/1800, Figueroa – Liddle/40.
[73] *Id.* 41-42.
[74] Staff/2800, Muldoon/26-27.
[75] PGE/600, Figueroa – Liddle/39-40.
[76] Staff/2800, Muldoon/26.

E. Discounted Cash Flow Model

Q. When Staff updated its DCF model, did it address the concerns you raised in your reply testimony about Staff's implementation of the model?

A. No, Staff updated its DCF model to incorporate recent data and correct estimates of the nominal growth rate sourced from the Energy Information Administration and the Social Security Administration.[77] As a result, Staff's three-stage DCF modeling results increased by 5 to 26 basis points to 9.22% to 9.46%.[78] Staff also updated its Gordon growth model, which slightly lowered its ROE estimates from 8.7% to 8.6%.[79] However, Staff did not address the various other flaws in its DCF methodology that I identified in my reply testimony, such as:

- Staff relies on an arbitrary averaging methodology and its multi-month duration is not reflective of current stock prices, as required by the DCF model;
- Staff's DCF relies on annual dividend payments, which is inconsistent with how utilities actually pay dividends, and delays the timing of payments to investors;
- Staff's DCF does not reflect other ways that companies can return cash flows to investors, such as stock buy backs; and
- While Staff accounts for differences in financial leverage, it does so by using a non-standard approach of applying the Hamada adjustment to the DCF.[80]

I continue to have serious concerns about Staff's implementation of the DCF model and find that its revised ROE estimates are downwardly biased as a result.

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[77] Errata to Rebuttal Testimony of Matt Muldoon, Exhibits 2400 and 2403, Docket No. UE 435, September 6, 2024.
[78] Staff/2800, Muldoon/18.
[79] Staff/400, Muldoon/30 and Staff/2800, Muldoon/30.
[80] PGE/1800, Figueroa – Liddle/14.

Q. Staff responds to your criticism about not reflecting other ways that Companies can return cash to investors by saying that it performed a CAPM sensitivity to reflect fully reinvested dividends rather than partially reinvested.[81] How do you respond?

A. First, I am assuming that Staff meant that it performed this sensitivity in its DCF model and not its CAPM since the CAPM does not rely on proxy sample growth rates in the calculation. Second, Staff is correct that a firm's free cash flow can be used to pay dividends or used as retained earnings and reinvested in the company to generate additional value through capital appreciation.[82] Relying on dividend growth rates, as Staff does, only accounts for one way that a company can return earnings to shareholders (*i.e.*, dividends) but ignores the additional returns that investors could get from reinvestments (*e.g.*, a utility uses retained earnings to fund a portion of its capital program, allowing it to add to its rate base) or share repurchases. The return required by equity investors is reflective of all the ways that a company can grow and generate value for investors, not just the value from dividends.

Staff corrects its DCF model to assume that investors reinvest all of their dividends into the company, which results in a higher ROE estimate of 9.8%, which Staff then eschews as not how investors actually behave.[83] This sensitivity falls short and does not address my concern with Staff's DCF. Reinvesting dividends in a company will increase an investor's holdings, which will result in more dividend payments to the investor in the future. But this still focuses solely on dividends and not the other ways a company can return earnings to investors. For example, Staff's sensitivity assumes the company still pays out earnings as

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[81] Staff/2800, Muldoon/32-33.
[82] *Id.* 32. I would also add that the Company can return earnings to shareholders via share repurchases.
[83] *Id.* 33.

dividends rather than re-investing earnings to generate additional value through capital appreciation.

As discussed in reply testimony, Staff can remedy this by relying on earnings growth rates (reflective of a company's growth in cash flow available to equity investors) rather than dividend growth rates (reflective of a specific way a company returns earnings to investors).[84] I find that Staff's DCF model results, including from its sensitivity, are downwardly biased.

Q. How does your long-term nominal GDP growth rate compare to the composite growth rate estimated by Staff?

A. Staff calculates an updated composite growth rate of 4.28% as well as growth rates of 4.06% and 4.58% based on estimates from the Congressional Budget Office and the Bureau of Economic Analysis, respectively.[85] Staff goes on to discuss that the general direction of long-term GDP growth rates is downward and argues that my testimony does not reflect the current, downward expectations for GDP growth rate.[86] However, in my multi-stage DCF analysis, I rely on a long-term nominal GDP growth of 4.0%, which is 6 to 58 basis points *below* Staff's revised growth rate estimates.[87] All else equal, updating the long-term nominal GDP growth rate estimate in my multi-stage DCF model to be consistent with Staff's current estimate would increase my ROE estimates.

[84] PGE/1800, Figueroa – Liddle/21-22.
[85] Staff/2800, Muldoon/24.
[86] *Id.* 25.
[87] PGE/600, Figueroa – Liddle/43.

F. Hamada Adjustment

Q. Staff argues that your criticism of their screen on proxy company's book capital structure rather than market value has no merit because it has updated its Hamada adjustments. Do you agree?

A. No, Staff Exhibit 2801/5 shows that Staff is still relying on book capital structure values as reported by *Value Line* to perform its Hamada Adjustment.[88] As I discuss in my reply testimony, Standard MBA textbooks including Berk and DeMarzo and Brealey, Myers, & Allen are clear that it is the market value capital structure of the proxy companies that is relevant when making adjustments for financial leverage.[89] I continue to find that there are serious concerns with Staff's implementation of the Hamada adjustment.

Q. Staff argues that its revised ROE estimates tests for a greater range of capital structures in its peer screen, which responds to your concerns about redundancy between the Hamada Adjustment and Staff's screening criteria. How do you respond?

A. In my reply testimony, I found that Staff's capital structure screen relies on arbitrary capital structure ratios and that differences in capital structure can be accounted for using well-established financial techniques such as the Hamada Adjustment.[90] In response, Staff relaxed its capital structure to include companies with book capital structures of 40% to 60% long term debt.[91] However, this is not responsive and does not address the point that Staff has not shown why a proxy utility with a capital structure outside of these parameters is not comparable to PGE. Further, a wider capital structure screen is still redundant with the

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[88] Staff/2801, Muldoon/5. *See also* proxy company's *Value Line* reports in Staff/2808.
[89] PGE/1800, Figueroa – Liddle/50-51.
[90] *Id.* 17.
[91] Staff/2800, Muldoon/11. Note, as discussed above, I also find it appropriate to look rely on a proxy company's market value capital structure rather than its book capital structure when accounting for differences in financial leverage.

Hamada Adjustment to the extent that Staff is concerned about the impact of capital structure on ROE estimates. Staff's revised capital structure screen suffers from the same faults as its original ROE analysis and should not be considered.

G. Return on Equity Conclusions

Q. Please summarize your findings and conclusions.

A. Having reviewed Staff's and AWEC's rebuttal testimony, I continue to find significant concerns with their ROE estimation methodology that downwardly bias the ROE estimates for PGE.[92] As discussed above, Staff and AWEC rely on the geometric mean to calculate the historic MRP for use in the CAPM, despite extensive academic research that consistently says the arithmetic mean should be used when estimating the cost of capital. AWEC uses Kroll's normalized MRP which is unreliable because it does not reflect the long-established and well-studied inverse relationship between investor risk premiums and interest rates. In addition, AWEC's estimates are derived using non-standard estimates of industry betas, which have not been shown to be generally better than Blume Adjusted betas, and AWEC offers no evidence that they are relied upon in regulatory settings to establish the allowed ROE for electric utilities. Staff's reliance on dividend growth rates downwardly biases the DCF results by not accounting for other ways companies return earnings to investors. Staff also incorrectly uses the proxy company's book capital structures in its Hamada adjustment methodology. These and other issues raised in my reply testimony raise serious concerns about Staff's and AWEC's ROE estimation methodology, which downwardly bias their ROE estimates by 60 to 215 bps.[93]

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[92] *See* PGE/1800, Figueroa – Liddle/7-8.
[93] *Id.* 11.

I continue to find that PGE's requested ROE of 9.65% at a 50.0% equity capital structure is reasonable. This reflects my consideration of recent developments in capital markets as well as my finding that PGE has higher business risk than the median risk profile of the proxy companies due to wildfires, its Power Cost Adjustment Mechanism, Oregon's clean energy and climate goals, and its smaller size.[94] Finally, this is also in consideration of recent trends in the allowed ROE for vertically integrated electricity utility, which indicates that PGE's requested ROE of 9.65% is in line with the average allowed ROE of 9.82% in 2024.

Q. Does the fact that you have not addressed all the issues in Staff and the Intervenor's rebuttal testimonies indicate that you agree?

A. No, it does not.

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[94] PGE/600, Figueroa – Liddle/51.

III. Capital Structure

Q. Please restate PGE's proposal on capital structure.

A. We maintain that a 50/50 debt to equity ratio is optimal. This recommendation is based on:

- Maintaining financial strength and liquidity
- Ensuring reliable access to capital markets
- Balancing costs for customers and shareholders

Our position is supported by industry peer data and helps mitigate risks associated with future leverage and purchased power agreements. This structure aligns with rating agency expectations and industry standards for financial risk management.

Q. What capital structure does Staff support for PGE?

A. Staff continues to support an equity percentage of 50%. Specifically, Staff highlights PGE's "consistent messaging … with the U.S. Security and Exchange Commission and with customers and investment banks" regarding PGE's long term financing goals.

Q. What is AWEC's recommendation?

A. AWEC continues to recommend an equity percentage 44.6%, however, in they state that "if PGE can demonstrate in surrebuttal testimony that it is making material progress toward the 2025 forecast, AWEC supports a capital structure of 47%."[95]

Q. How did AWEC respond to PGE's demonstration that AWEC is not using the correct regulated equity percentage?

A. Despite noting in PGE Exhibit 1800 that 47.4% is the correct average equity value for 2023 as filed within PGE's annual results of operations (ROO) report with the OPUC, AWEC continues to question the accuracy of this value. Not only did PGE provide AWEC with the

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[95] AWEC/400, Kaufman/24 at 13-14.

ROO filings for the last several years, AWEC has access to docket RE 119, where PGE's reports are filed. They do, however, note that it is possible for a year-end value to be disconnected from an average value.[96]

Q. How did AWEC respond to Table 3 in PGE Exhibit 1800 demonstrating that PGE's common average equity has indeed averaged to 49.9% over the past 10 years?

A. AWEC did not address the information provided.

Q. How did AWEC respond to PGE's point that since 2019 PGE has been absorbing financial events such as the COVID pandemic, wildfires and major storms onto its balance sheet?

A. AWEC did not address the information provided.

Q. What does AWEC say in its rebuttal testimony to continue to support an equity percentage below 50%?

A. AWEC maintains their positions from their opening testimony and continues to argue that PGE's actual equity is projected to be lower than the proposed 50% within the test year.

They do not provide any further support for the recommendations they had made in their opening testimony regarding credit metrics, which PGE addressed fully in PGE Exhibit 1800.

Q. Does PGE agree that a utility should maintain its authorized equity percentage precisely as set in rates during the test year?

A. No. Maintaining an exact debt-to-equity percentage annually is impractical and potentially cost-prohibitive due to the scale and timing of debt and equity issuances. Furthermore, PGE has shown that over time, our regulated equity percentage continues to remain almost exactly at 50%.

[96] AWEC/400, Kaufman/24.

IV. Cost of Debt

Q. Did Staff propose any further adjustments to PGE's cost of debt?

A. No. Staff maintained their proposal of an overall cost of long-term debt of 4.641%, comprised of 4.548% for outstanding LT Debt and 5.746% for forecasted issuances. PGE supported this value in its reply testimony and incorporated it into its revenue requirement model.

Q. Have there been any changes in the market to suggest that this percentage should change?

A. The Federal Reserve decreased rates by 50 basis points on September 18, 2024. As mentioned in the ROE discussion above, treasury rates have actually increased since the rate cut, with the yield on a 30-year U.S. Treasury increasing from 3.96% on September 17, 2024 to 4.14% on September 25, 2024.[97]

Q. Are there any other reasons why this change should not impact the currently agreed upon debt percentage downward?

A. Yes. Through discovery, Staff requested that PGE provide an update of PGE's anticipated weighted cost of debt for 2025. This update, provided on August 30, 2025, shows a weighted cost of debt of 4.660%, which is another 19 basis points higher than the cost of debt PGE and Staff currently agree upon.

Q. Is PGE recommending any changes to the cost of debt?

A. No. PGE maintains that a 4.641% cost of debt is a fair and reasonable outcome for this filing.

Q. Does this conclude your testimony?

A. Yes.

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[97] FRED, "Market Yield on U.S. Treasury Securities at 30-Year Constant Maturity," DGS30, accessed September 26, 2024.

List of Exhibits

PGE Exhibit	Description
2901C	Allowed ROEs

UE 435

Exhibit 2901 has been retained and provided in its native format

Additionally Exhibit 2901 is CONFIDENTIAL pursuant to General Protective Order No. 23-132

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 435

Marginal Cost of Service

PORTLAND GENERAL ELECTRIC COMPANY

Surrebuttal Testimony of

Robert Macfarlane

October 1, 2024

Table of Contents

I. Introduction and Summary

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

A. My name is Robert Macfarlane. I am a Manager in Pricing and Tariffs at Portland General Electric Company (PGE). I am responsible for the development of the marginal cost studies. My qualifications are included in PGE Exhibit 800.

Q. What is the purpose of your testimony?

A. My testimony responds to certain recommendations made by the Alliance of Western Energy Consumers (AWEC) regarding PGE's proposals to update the generation marginal cost studies. No other party to this proceeding has provided recommendations regarding PGE's marginal cost studies. Staff of the Public Utility Commission of Oregon (Staff) reviewed PGE's model, and the rationale provided in our testimony and did not have any issues with the changes made to the studies. The Citizens' Utility Board (CUB) did not propose any changes to PGE's generation marginal cost study. I outline AWEC's arguments and respond to their proposals.

Q. How is the remainder of your testimony organized?

A. After this introduction, my testimony has three sections:

1. Section II – Overview and Summary
2. Section III – Generation Marginal Cost Study
3. Section IV – Customer Marginal Cost Study

II. Overview and Summary

Q. Please provide an overview of AWEC's proposals regarding PGE's generation marginal cost study.

A. AWEC maintains all recommendations made in AWEC Exhibit 200:

1. Remove capacity value from the cost of wind and solar resources when estimating the cost of energy. Do not remove capacity value of wind and solar from battery resources.
2. Use tuned effective load carrying capacity (ELCC) under firm transmission for all resources.
3. Use local wind and solar resources when modeling the cost of energy, consistent with PGE's preferred portfolio in the 2023 Integrated Resource Plan ("IRP") and Clean Energy Plan ("CEP"). Alternatively, use Clearwater wind transmission costs for the Montana wind resource, which provides a more precise estimate of transmission costs, and 100% ELCC for the Mead solar resource.
4. Use flat Mid-C prices from PGE's Green House Gas (GHG) model.
5. Do not remove flexibility value from battery cost to calculate the net cost of capacity.

Q. Are any elements of the above proposals acceptable to PGE?

A. No.

Q. How does Staff respond to AWEC's above proposals?

A. Staff does not agree with AWEC's proposals. Staff agrees with PGE's rebuttals of these proposals. Staff reiterates that resource planning has changed significantly since PGE's legacy methodology was developed. Staff also agrees that, while there is capacity value captured by procuring renewable resources, that value does not reduce the need to procure renewable resources to meet the Company's energy needs. Staff believes the holistic approach and outcome from PGE's marginal cost model seems to produce reasonable results given Staff's current understanding of the Company's cost drivers and long-term strategy. Staff highlights that AWEC's proposals drastically increase the marginal capacity cost and decrease the marginal energy cost, largely benefitting the customers they represent.[1]

Q. Did AWEC or Staff take issue with the other updates to PGE's generation marginal cost study not proposed in Exhibit AWEC/200?

A. No.

Q. What actions does PGE recommend the Commission take regarding these proposals?

A. PGE recommends that the Commission reject AWEC's proposals to alter the generation marginal cost of service.

[1] Staff/3000, Stevens /6 at 10-20.

III. Generation Marginal Cost Study

A. Capacity Value of Solar and Wind Proxy Resources

Q. Does AWEC agree with PGE's method of addressing wind and solar capacity value?

A. No. AWEC recommends removing the capacity value from the cost of wind and solar resources when calculating the cost of energy, and not removing the capacity value of wind and solar from battery resources when calculating the cost of capacity.

Q. How does AWEC support this recommendation?

A. AWEC's first argument is that their recommendation is "consistent with the standard marginal cost of generation methodology."[2]

Q. Did you address this argument in reply testimony?

A. Yes.

Q. Did AWEC address or acknowledge PGE's response to this argument?

A. No.

Q. How did you respond in reply testimony?

A. AWEC claims "the standard method of addressing the capacity value of energy resources is to subtract the capacity value of the energy resource from the cost of energy, not to subtract the capacity value of energy resources from the cost of capacity."[3]

AWEC's only support for this claim is that PGE used this methodology in the UE 394 Generation Marginal Cost Study that relies on a combined cycle combustion turbine (CCCT) as the "marginal long-run generation resource…used to provide both energy and capacity."[4]

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[2] AWEC/400, Kaufman /2 at 3.
[3] AWEC/200, Kaufman /11 at 7-9.
[4] *In the Matter of Portland General Electric Company Request for a General Rate Revision*, Docket UE 394, PGE/1100, Macfarlane – Pleasant/2 at 7-19 (Jul 9, 2021).

PGE's legacy approach of isolating the CCCT's embedded capacity value from its total cost is not instructive to PGE's proposed model which improves our ability to accurately calculate the marginal cost of generation as we plan for a carbon-free future. A CCCT brings both energy and capacity value to PGE's system and therefore provides a different starting point for PGE's legacy methodology. The same resource provides 100% of capacity and energy need, so for the purpose of a generation marginal cost study, its cost is divided into energy and capacity using a proxy capacity resource, the single cycle combustion turbine (SCCT).

PGE's proposed model reflects future resources that are non-carbon emitting. The capacity factor of the renewable energy resource determines the amount of renewable resources needed to produce enough electricity across the year to equal the CCCT's annual production. The effective load carrying capability (ELCC) of the renewable resource is used to determine the amount of batteries needed to serve the capacity need not provided by the renewable energy resources.

Q. Does AWEC have any other arguments supporting their recommendation to subtract the capacity value of the energy resource from the cost of energy, not to subtract the capacity value of energy resources from the cost of capacity?

A. Yes, AWEC claims PGE's model is flawed because modeling energy resources with a high ELCC; such as hydro, hybrid solar and battery, hybrid wind and battery, and geothermal resources; results in a finding that capacity costs are zero.

Q. How does PGE respond?

A. PGE stated in its reply testimony that it is inappropriate to use a peaking resource to replace a variable resource in PGE's model.[5] Peaking resources have ELCCs close to 100%, whereas the ELCC values of the solar and wind proxy renewable resources in PGE's model are 7% and 27% respectively.[6] If PGE were to replace its energy proxy with a peaking resource, then there would be no need for a battery. A resource with a 100% ELCC would provide 100% of capacity and energy need, so PGE's proposed generation marginal cost study methodology would not apply.

Q. Did AWEC acknowledge that if PGE were to use an energy proxy with a 100% ELCC, then there would be no need for a battery and therefore PGE's proposed generation marginal cost study methodology would not apply?

A. No. AWEC did not respond to this argument in their reply testimony.

Q. How did AWEC respond?

A. AWEC did not provide a clear response. AWEC states that hybrid solar and wind are more expensive than solar and wind, therefore it is "absurd to argue that capacity costs are zero".[7] AWEC later makes the point that hourly market prices reflect capacity costs.[8]

Q. How does PGE respond?

A. PGE's model does not calculate capacity costs as zero. As explained in opening testimony, in a non-emitting framework, PGE uses solar and wind as proxy energy resources and battery

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[5] AWEC/200, Kaufman/7 at 1. AWEC's Figure 1 shows hydro as a peaking resource.

[6] *See* 2026-43 average tuned ELCCs for MT wind and Wasco solar in PGE's 2023 IRP, *In the Matter of Portland General Electric Company's Clean Energy Plan and Integrated Resource Plan*, LC 80, PGE's 2023 Clean Energy Plan and Integrated Resource Plan at 546-547 (Mar 31, 2023).

[7] AWEC/400, Kaufman /2 at 17.

[8] AWEC/400, Kaufman /2 at 18-21.

resource as the proxy capacity resource and therefore PGE's model captures the capacity value of energy and capacity resources and their costs.

Q. Does AWEC offer other arguments supporting their recommendation to subtract the capacity value of the energy resource from the cost of energy, and not to subtract the capacity value of energy resources from the cost of capacity?

A. Yes, AWEC argues that PGE's model mismatches the cost of capacity with the amount of capacity served. AWEC claims that PGE's model is incorrect because subtracting the value of the capacity contribution of the energy proxy from the cost of capacity reduces the amount of capacity served by the model. AWEC illustrates this with the following example:

> For example, a 1 kW wind resource with 30 percent ELCC would leave 0.7 kW of capacity that needs to be served by the battery, thus the cost of the battery is scaled down from 1 kW to 0.7 kW. However, PGE fails to account for the fact that the smaller battery resource is now serving a smaller demand. As a result, PGE's model does not measure the cost of serving 1 kW of capacity, but rather the cost of serving 0.7 kW of capacity. [9]

Q. Does PGE agree with AWEC's position on how the energy resource impacts capacity modeled?

A. No. Following AWEC's example, PGE is still modeling the cost to serve 1 kW of capacity, not 0.7 kW of capacity. A capacity value of 0.7 kW is served from the 4-hour battery and 0.3 kW of capacity is served by the energy proxy. Batteries do not generate electricity,[10] but renewable resources do contribute some capacity. In our generation marginal cost study, less battery capacity is needed because the energy proxy provides a portion of the capacity need. PGE still needs to procure the same amount of renewable energy regardless of the capacity contribution of the resource.

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[9] AWEC/200, Kaufman/10-11.

[10] In fact, batteries lose 14% of stored energy. The ratio of useful energy output to useful energy input of a 4-hour battery is 86%. *See* LC 80, PGE's 2023 Clean Energy Plan and Integrated Resource Plan at 183 (Mar 31, 2023).

PGE procures battery resources to provide capacity and wind and solar resources to provide energy and environmental attributes. Renewable resources capacity contribution reduces the battery capacity needed and therefore reduces the cost of capacity. The capacity contribution of renewables does not reduce the amount of energy needed, therefore there is no reduction to the cost of energy.

Q. How did AWEC respond in their rebuttal testimony to PGE's response?

A. AWEC claims that PGE's approach assumes the 0.3 kW of capacity is provided at no cost. AWEC argues that PGE has modeled high-cost energy resources that provide resource diversity and capacity, rather than low-cost energy resources with little capacity value.

Q. How does PGE respond to AWEC's assertion that under PGE's methodology, 0.3kW capacity value of the energy resource is provided at no cost?

A. AWEC erroneously claims PGE's approach assumes the 0.3 kW of capacity is provided at no cost. The cost of the 0.3 kW of capacity is included in cost of the energy resource. If we consider the same hypothetical provided by AWEC, but instead used their methodology, then the model would measure the cost of serving over 1 kW of capacity and the cost of serving less than 1 kW of energy.

B. ELCC

Q. What solar and wind ELCCs does PGE use in their generation marginal cost model?

A. The ELCC values of the solar and wind proxy resources in PGE's model are 7% and 27% respectively. PGE averages the conditional firm and firm transmission ELCC values of solar and wind proxies from years 2026-43. [11]

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[11] *See* 2026-43 average tuned ELCCs for MT wind and Wasco solar in PGE's 2023 IRP, *In the Matter of Portland General Electric Company's Clean Energy Plan and Integrated Resource Plan*, LC 80, PGE's 2023 Clean Energy Plan and Integrated Resource Plan at 546-547 (Mar 31, 2023).

Q. What are AWEC's recommendations regarding the ELCC of the wind and solar proxy resources?

A. AWEC recommends that tuned ELCC under firm transmission be used for all resources in the marginal cost study

Q. How did you explain the use of the ELCC values in opening testimony?

A. Even though PGE includes the cost of PGE-owned transmission resources when calculating the cost of energy resources, that does not eliminate the risk of conditional firm transmission. The proxy energy resources would still go over BPA's system, meaning it is still possible they would get a decrement from conditional firm transmission.

It is very difficult to procure firm transmission in the current environment. In a long-run marginal cost study it would be inappropriate to assume 100% firm transmission.

Q. How did AWEC respond?

A. AWEC baselessly and erroneously claims that PGE's 2023 IRP models do not use conditional firm ELCC when modeling resources that use PGE-owned transmission.[12]

Q. How does PGE respond?

A. Table 133 of PGE's IRP provides both conditional and firm ELCC values for modeling resources that use PGE-owned transmission.[13] Additionally, PGE's portfolio analysis in the 2023 CEP/IRP also included options for resources bringing both firm and conditional firm transmission.

[12] AWEC/400, Kaufman /6 at 3-4.
[13] PGE's 2023 IRP, *In the Matter of Portland General Electric Company's Clean Energy Plan and Integrated Resource Plan*, LC 80, PGE's 2023 Clean Energy Plan and Integrated Resource Plan at 546-547 (Mar 31, 2023).

Q. Does AWEC have any other concerns with the solar proxy ELCC PGE used?

A. Yes. AWEC argues the transmission enabling Mead solar is paired with a 100% ELCC. Thus, PGE's model cannot procure Mead solar without also acquiring a resource with 100% ELCC. In addition, the costly transmission required to procure Mead solar is not economic without the associated capacity.[14]

Q. How does PGE respond?

A. AWEC's claim that a solar or wind proxy resource should have a 100% ELCC is clearly false. Proxy resource ELCCs should reflect the capacity contribution of the proxy resource, not of the energy market plus the resource. Forecasted market purchases are included separately in PGE's model and separately account for the contribution of market access in the calculation of the cost of energy. One can easily intuit that it would be impossible for any solar resource to supply 100% of PGE's capacity need.

Q. Did AWEC have any new arguments regarding transmission costs?

A. AWEC disputes PGE's transmission proxy for Montana wind because there will be additional transmission available when PGE stops transmitting energy from Colstrip.

Q. How does PGE respond?

A. PGE will still be transmitting energy from Colstrip until 2027. It is possible PGE won't fully stop transmitting energy from Colstrip until 2030, five years after the start date of the Montana wind proxy resource in PGE's model.

C. Mid-C Prices

Q. Does AWEC have any new arguments regarding Mid-C Prices?

A. AWEC misrepresents that PGE claims that prices do not affect market purchases.

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[14] AWEC/400, Kaufman/6 at 10-13.

Q. What is PGE's position?

A. AWEC erroneously claimed in their opening testimony that market purchases in the GHG model are a function of the forecasted prices, and PGE simply noted in reply testimony that changing the market prices in the GHG model has no impact on market purchases. Market purchases in the GHG model are only based on historical purchases.

Q. How does PGE respond to AWEC's concern that PGE escalates market prices using inflation?

A. PGE's model escalates the cost of all resources by inflation. There is no support that market prices should not be escalated. It is a conservative assumption to escalate 2025 market prices by inflation considering HB2021 emissions goals and industry-wide load growth will have upward pressure on market prices.

Q. Does AWEC have any other arguments regarding Mid-C Prices?

A. Yes. AWEC argues the Mid-C prices shaped by loss of load probability used in PGE's model reflect capacity constraints rather than energy costs, therefore flat energy prices are more appropriate when estimating energy costs "regardless of whether PGE's method accurately estimates the cost of purchased energy."[15]

Q. How does PGE respond?

A. Market energy purchases are clearly energy costs, not a capacity cost as AWEC suggests. PGE disagrees with AWEC and asserts that accuracy and reasonableness should be considered when modeling the price of estimated market purchases. As PGE stated in reply testimony, loss of load shaping reflects the price of market energy when energy purchases are needed,

[15] AWEC/400, Kaufman/9 at 18-19.

not an unweighted annual average price as AWEC recommends. PGE's methodology is a more accurate estimation of the cost of market purchases.

D. Flexibility Value

Q. Does AWEC have any new arguments regarding the flexibility value of storage?

A. AWEC argues that PGE's model does not consider the value of a day-ahead capacity product and therefore the flexibility value of a 4-hour battery should not be removed from the cost of capacity.

Q. Does PGE agree?

A. No. PGE's model does consider the value of a day-ahead capacity product because it is an input to the flexibility value estimation.

IV. Customer Marginal Cost Study

Q. Please describe proposals put forward by Parties in response to the customer marginal cost study filed in PGE's opening testimony.

A. Parties did not put forth any additional proposals or comments in rebuttal testimony in response to the changes we made in PGE Exhibit 1900 to accommodate AWEC's proposals in opening testimony.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 435

Pricing and Tariff

PORTLAND GENERAL ELECTRIC COMPANY

Surrebuttal Testimony of

Robert Macfarlane
Christopher Pleasant

October 1, 2024

Table of Contents

I. Introduction and Summary

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

A. My name is Robert Macfarlane. I am the Manager of Pricing and Tariffs for PGE. My qualifications were previously provided in PGE Exhibit 800.

My name is Christopher Pleasant. I am a Senior Regulatory Analyst in Pricing and Tariffs for PGE. My qualifications were previously provided in PGE Exhibit 900.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to respond to the rebuttal testimony provided by the Staff of the Public Utility Commission of Oregon (Staff), the Citizens' Utility Board of Oregon (CUB), the Alliance of Western Energy Consumers (AWEC), and Verde (collectively, Parties). We also provide an update of the overall rate impacts and the impacts to various PGE rate schedules consistent with PGE's recently updated 2025 Load Forecast from September 2024 and the current Revenue Requirement as provided in Exhibit 2401.

Q. How is the remainder of your testimony organized?

A. Section II provides an update of the overall rate impacts and impacts to the various PGE rate schedules based on:

- PGE's latest Load Forecast from September 2024;
- Revenue Requirement as described in Exhibit 2401:
- Removal of the Clearwater customer benefit from current prices due to schedule delays in UE 427, with a Commission order now expected in early 2025 in UE 427: and
- Currently known and measurable Supplemental Schedules for January 1, 2025.

Section III will address Staff's and CUB's rebuttal testimony on the Residential Basic Charge; Staff and CUB continue to recommend the Residential Basic Charge remain at the current price of $13 for Single Family and $10 for Multi-Family instead of the $2 increases PGE proposes. PGE reiterates an increase to the Residential Basic Charge is necessary and will have no bill impacts for low-income customers.

Section IV addresses Staff's proposal that PGE extend a mid-peak window as part of PGE's Commercial Time-of Use (TOU) proposal, which introduces a mid-peak window for Schedules 38, 83, 85 and 89. We discuss why extending a mid-peak window to Schedule 90 is not necessary. AWEC also agrees with PGE that a mid-peak window is not necessary.

Section V addresses Staff's and CUB's rebuttal testimony on the Load Following Credit for Schedule 90. Staff and CUB continue to oppose PGE's updated Load Following Credit price, which is based on the flexibility of a 4-hour battery. AWEC supports PGE's updated Load Following Credit price. PGE continues to maintain that the proposed Load Following Credit price is appropriate and justified.

Section VI summarizes the Parties' positions on PGE's proposed Rate Spread. Specifically, the use of the Customer Impact Offset (CIO). PGE recommends the Commission adopt PGE's method for implementing a CIO in this case.

Section VII summarizes the Parties' positions on PGE's proposed Transportation Electrification Line Extension Allowance proposal. PGE recommends the Commission adopt a permanent Transportation Electrification Line Extension Allowance.

Section VIII summarizes PGE's load forecast update consistent with Section II. This update incorporates the latest historical data and inputs into PGE's 2025 test year load forecast. No methodological changes were made.

Section IX responds to CUB's rebuttal testimony concerning PGE's Bill and the actions we are taking related to bill design.

II. Proposed Rate Impacts

Q. Please summarize the updated projected 2025 Cost of Service (COS) rate impacts.

A. Table 1, below, summarizes the base rate impacts effective January 1, 2025, for the major rate schedules. Column A is the revenue requirement in this case, including the Constable Battery Project. Column B is the 2025 net variable power costs proposed under Docket UE 436. Column C is the estimated changes in supplemental schedules currently known and measurable. Column D shows the rate adjustment for January 1, 2025, associated with items indicated in Columns, A, B and C.

Table 1
Estimated Cost of Service Impacts Inclusive of Proposed Base Rates and Changes to Schedules 105, 123, 125, 126, 131, 135, 136, 137, 138, 152 & 153 (all other supplementals at current prices)[1]

	A	B	C	D
Schedule	**UE 435 Revenue Requirement + Constable 1/1/2025**	**UE 436 Power Costs 1/1/2025**	**Supplemental Schedules 1/1/25[2]**	**GRC+ Power Costs + Supplementals 1/1/25 Combined**
Schedule 7 Residential	7.9%	0.4%	0.1%	8.4%
Schedule 32 Small Nonresidential	11.6%	0.0%	-1.4%	10.3%
Schedule 83 31-200 kW	10.7%	0.2%	-0.1%	10.8%
Schedule 85 201-4,000 kW	9.8%	0.0%	-0.6%	9.1%
Schedule 89 Over 4,000 kW	10.4%	-0.1%	-0.7%	9.6%
Schedule 90 Over 30 MWa	5.1%	0.0%	-0.7%	4.5%
COS & DA Overall	8.6%	0.3%	-0.3%	8.6%

Note: Percentages in columns A-C may not sum to column D due to rounding.

[1] The following schedules are set to zero on January 1, 2025: 123 Decoupling, 126 Annual Power Cost Variance Mechanism, and 131 Oregon Commercial Activities Tax Recovery. The following Schedules are estimated to change January 1, 2025: Schedule 105 Regulatory Adjustments, Schedule 135 Demand Response Cost Recovery, Schedule 136, Oregon Community Solar Cost Recovery, Schedule 137 Customer Owned Solar Payment Option Cost Recovery, Schedule 138, Energy Storage Cost Recovery, Schedule 152 Major Event Cost Recovery, and Schedule 153 Community Benefits Impacts Advisory Group Cost Recovery. Additional Supplemental Schedules may have updates January 1, 2025 but are not known at this time.

[2] The following Schedules are expected to have a mid-year price change and not included in Column C currently: Schedule 109 Energy Efficiency, Schedule 122 Renewable Resources Automatic Adjustment Clause, Schedule 149 Environmental Remediation Cost Recovery Adjustment, Schedule 151 Wildfire Mitigation Cost Recovery, and Schedule 152 Major Event Cost Recovery.

Q. Please respond to CUB's concerns that estimated price updates to supplemental schedules are not publicly available.

A. In rebuttal testimony, CUB points to the short window between Commission-approved, final 2024 prices for certain supplemental schedules and their January 1, 2024 effective date as indication of PGE's avoidance of transparent ratemaking.[3] In the current rate review, PGE has consistently included estimated rate impacts of known and measurable adjustments to supplemental schedule prices in the presentation of impacts associated with base rates.

III. Residential Basic Charge

Q. Please summarize PGE's Residential Basic Charge request.

A. PGE continues to propose an increase to the Residential Basic Charge by $2, from $13 to $15 monthly for single-family and $10 to $12 monthly for multi-family. Embedded customer costs suggest a Basic Charge of approximately $30. The proposed $2 increase to the Basic Charge is then offset by a 0.25 cent/kWh decrease to the proposed distribution charge. The impact of these adjustments is decreased bills when customers use more than the residential average amount (~800 kWh) and up to a $2 increase when customers use less than the residential average. Many customers will experience this proposal as moderating bills during high bill seasons despite slight increases during temperate months when bills are naturally lower. This smoothing can be helpful for lower income customers with more variable usage season to season.

[3] CUB/400, Jenks/10 at 4-7.

Q. Have Staff or CUB changed their position regarding PGE's request concerning the Residential Basic Charge?

A. No. Staff and CUB still withhold support for PGE's proposal, raising concerns around bill impacts to low-income low-use customers and the frequency of recent increases to the residential Basic Charge being at odds with gradualism. In rebuttal testimony, Staff continued their argument that PGE's embedded residential Basic Charge calculation of roughly $30 is inflated due to inclusion of longer-run costs like distribution line transformers. In discovery, however, Staff recognized the inconsistency between their current position and that previously documented in a prior PGE rate review as provided in Exhibit 3101.CUB argues that raising the Basic Charge adversely impacts the customer's bill savings when the customer invests in energy efficiency.[4]

Q. How do you respond to Staff's and CUB's concern that raising the Residential Basic Charge adversely impacts low-income customers?

A. PGE presented evidence in opening and reply testimony showing that raising the basic charge and reducing the volumetric distribution charge would help smooth customer bills over the course of the year. This impact helps temper winter bill increases and can improve affordability for many low-income customers during high bill season. PGE's proposal is particularly beneficial to customers with high energy burdens who are just over the income eligibility criteria for PGE's IQBD program.[5] In rebuttal testimony, Staff recognized PGE's responsiveness to their request for further analysis of equity impacts of the Basic Charge increase[6] but indicates more analysis is needed to understand better which customers stand to

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[4] CUB/500, Tran/8 at 23-24.
[5] PGE/2000, Macfarlane-Pleasant/7 at 3-8.
[6] Staff/3000, Stevens/15 at 8-9.

benefit the most from an increased basic charge before they could potentially support PGE's proposal. To this end, PGE assessed more significant savings potential, by estimated income range, using data from PGE's 2024 Energy Burden Assessment. The portion of customers who stand to benefit most (i.e., have average usage above 1,600 kWh) during the winter months is consistent across income bands, about 15-16%, suggesting that an increased Basic Charge would not disproportionately harm low-income customers during the months when customers tend to be most concerned about their bills. During the summer months, there is slightly more correlation between income ranges and usage above 1,600 kWh, 6-10% of households over 60% SMI versus 5-6% of households under 60% SMI.

Q. How do you respond to Staff's and CUB's concern that an increase of $2 is counter to a gradualism principle?

A. PGE disagrees with Staff and CUB's assessment that PGE's proposal violates principles of gradualism. PGE has regularly proposed small increases to the Residential Basic Charge in prior rate reviews, with the exception of UE 394, and has only received approval between 2010 to 2022 to increase the charge by $2. This is an extreme interpretation of the gradualism principle.

PGE reiterates the importance of proportionate allocations of residential increases to both the volumetric charges and the fixed Basic Charge so long as the Basic Charge remains below the calculated embedded value. This allows PGE to reasonably maintain proportional recovery of fixed costs with a fixed charge; an increase to the Basic Charge is offset with a decrease to the per kWh distribution charge which can benefit customers. Staff does not have an issue with how PGE sets the Commercial Basic Charge, which is based on this same principle. Staff regularly agrees with PGE's proposed Commercial Basic Charge proposals, and only brings up gradualism when PGE requests to increase the Residential Basic Charge. In UE 197 the embedded residential Basic Charge suggested a basic charge of approximately $11 and PGE maintained the basic charge of $10 at the time.[7] We are at this point because Staff and CUB have refused to allow PGE to increase the residential basic charge over time similar to how PGE increases the commercial basic charges. Instead of increasing the Residential Basic Charge gradually, Staff and CUB appear to prefer that the Residential Basic Charge increase at a glacial pace.

Q. How do you respond to Staff's argument that the existing components included in PGE's embedded Basic Charge marginal cost should be considered an upper bound?

A. Staff states that it is their long-standing position that transformers are inappropriate to include in the cost-basis for basic charges.[8] However, Staff has never directly taken this position specifically that transformers are inappropriate to include in the cost-basis for basic charges. The most recent in-depth discussion on what components should be included in the calculation of the basic charge occurred in 2015, over 9 years ago in UE 283, PGE's 2015 Rate Review. Staff's testimony at that time seemed to indicate they support including the local distribution transformer in the basic charge calculation, where Staff in its self-described "A Short Treatise on Basic Charges" identified distribution transformers as one of the universally recognized customer cost/basic charge components. [9]

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[7] *In The Matter of Portland General Electric Company Request for General Rate Revision*, Docket UE 197, PGE/1200, Kuns-Cody/7 at 8-10 (Feb 27, 2008).
[8] Staff/3000, Stevens/12 at 18-20.
[9] *In the Matter of Portland General Electric Company Request for a General Rate Revision*, Docket UE 283, Staff/700, Compton/11 at 27-29 and Compton/12 at 1-2 (Jun. 11, 2014).

Q. What else did Staff say in its "Short Treatise on Basic Charges" should be included components for the basic charge?

A. Staff included costs inevitably incurred by each customer *individually* in being served. Examples are the meter, meter-reading, and billing, the service drop between the local distribution transformer and the meter, and the distribution transformer itself, or at least a minimal share thereof in the case when the transformer can simultaneously serve more than one customer.[10]

Q. Is Staff's current position that the embedded Basic Charge should be considered the upper bound consistent with Staff's prior position on this issue?

A. In PGE's previous two rate reviews, Staff did not propose that PGE's embedded Basic Charge should be considered an upper bound. We still maintain that PGE's embedded Basic Charge calculation represents the actual fixed costs to serve residential customers and that the transformer category is appropriate. Transformers are not a longer-term programmatic cost because of the number of new residential connection requests PGE receives from builders on an annual basis. As shown in Exhibit 3102, between 2021 to 2024 YTD PGE received 6,166 new residential connections. Of these requests, 66% required PGE to install a transformer and only 34% were able to connect to the system using the existing transformer. Due to ongoing residential new connection requests, the majority of which require a transformer, it is appropriate to include transformers in PGE's embedded basic charge calculation.

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[10] *In the Matter of Portland General Electric Company Request for a General Rate Revision*, Docket UE 283, Staff/700, Compton/11 at 27-29 and Compton/12 at 1-2 (Jun. 11, 2014).

Q. CUB asserts raising the basic charge could result in customers facing higher Schedule 109 charges. Is this correct?

A. PGE finds CUB's argument to be overstated given PGE's modest proposal. CUB suggests that the 0.25 cent/kWh reduction to the residential price per kWh will deter energy efficiency (EE) investments and that an increase in Energy Trust of Oregon (ETO) incentives will be needed to maintain EE adoption levels. Following this line of thinking, CUB raises concern that the collections that fund the ETO, charged via Schedule 109, could similarly increase.

Investments in EE have a 40-plus year history in Oregon, driven in part by estimated future bill savings, but also by customers' desire to reduce emissions, receive State and/or Federal tax rebates, and increase the value of their home. PGE thinks CUB's concern about increases to Schedule 109 ignores these additional, foundational drivers for EE adoption.

Q. What is PGE's recommendation regarding the residential Basic Charge?

A. We recommend the Commission approve PGE's proposed $2 increase in the Residential Basic Charge from $13 to $15 monthly for single-family homes and from $10 to $12 monthly for units in multi-family buildings, offset by a decrease to the per-kWh distribution price. Alternately, if the Commission has remaining concerns about potential impacts to low income customers associated with PGE's proposal, the Company could offset this fixed increase by providing a fixed credit to customers enrolled in Schedule 18, PGE's Income-Qualified Bill Discount.

IV. Commercial Time of Use

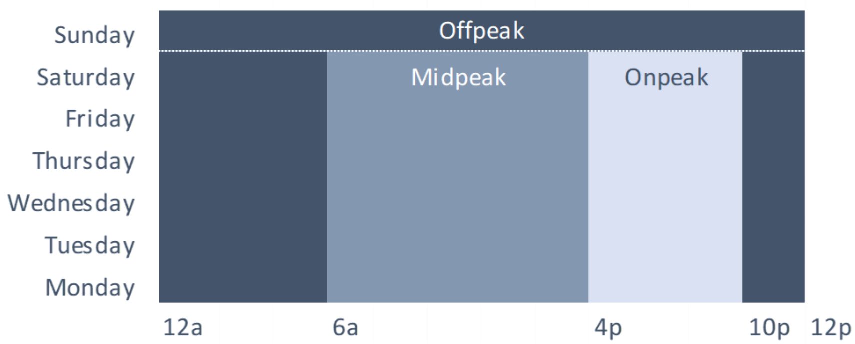
Q. Please summarize PGE's proposal regarding Commercial Time of Use (TOU) rates.

A. PGE requests to restructure its current Commercial TOU rate structure, which currently only has on-peak and off-peak windows, by adding a mid-peak window to Schedules 38, 83, 85 and 89. PGE would do this by bifurcating the current on-peak window to create a mid-peak window. The proposed energy structure charges will be:

- On-peak: Monday through Saturday 4 p.m. to 10 p.m.
- Mid-peak: Monday through Saturday 6 a.m. to 4 p.m.
- Off-peak: Monday through Saturday, 10 p.m. – 6 a.m., and all hours on Sundays.

Figure 1 illustrates PGE's proposal.

Figure 1
Revised Proposal for TOU Periods – Schedules 38, 83, 85 & 89



Q. Please summarize Parties' rebuttal testimony regarding PGE's proposal concerning Commercial TOU Rates.

A. Staff generally supports the Company's Commercial TOU rate proposal. In Staff's opening testimony they recommended minor changes to the Company's on-, mid-, and off-peak differentials applied to Schedules 38, 83, 85, and 89 which in PGE's reply testimony we agreed to update based on Staff's recommendation. In Staff's opening and rebuttal testimony Staff recommends that PGE extend the Company's Commercial TOU rate proposal to

Schedule 90, which is for customers whose demand is above 4,000 kW, have an aggregate load to at least 30 MWa and maintain a load factor of 80% or greater for each account. Staff makes this recommendation to align cost recovery with the time-varying nature of electricity generation costs and incentivize customers to move their consumption away from the highest cost periods. Even if customers cannot shift their load the Company still incurs a cost to procure or generate energy for these customers which they should pay for. [11]

AWEC did not discuss PGE's Commercial TOU rate proposal for Schedules 38, 83, 85 and 89 in their opening or rebuttal testimonies.

However, in AWEC's rebuttal testimony, they did discuss Staff's recommendation that PGE should introduce a mid-peak window to Schedule 90. AWEC does not agree with Staff's recommendation and argues that incentivizing Schedule 90 customers to maintain a flat load is preferable to introducing a TOU rate. It is also unclear that Schedule 90 customers have the type of manufacturing processes that would allow them to shift usage to take advantage of a TOU rate. Finally, since Staff provided no specific TOU design proposal for Schedule 90 for AWEC to comment on, AWEC cannot evaluate the validity of Staff's recommendation. AWEC requests that a TOU rate not be extended to Schedule 90 until AWEC has an opportunity to review, analyze, and comment on the specific rate design and more is understood about the ability of Schedule 90 customers to shift load.[12]

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[11] Staff/2400, Dlouhy/22 at 5-11.
[12] AWEC/400, Kaufman/15 at 7-14.

Q. Do you agree with Staff that implementing a mid-peak window to Schedule 90 will align cost recovery with the time-varying nature of electricity generation costs and incentivize customers to move their consumption off the highest cost periods?

A. No. Staff in their rebuttal testimony did not offer any new evidence that indicates implementing a mid-peak window to Schedule 90 would benefit customers on that schedule or provide a system benefit overall. The current Schedule 90 rate already aligns its costs with the rate they are charged since Schedule 90 customers have a load shape that is relatively flat. These customers typically have monthly load factors in the 90-100% range. PGE plans for these customers' load in our long-term power planning and PGE does not incur higher costs to serve this load in high-demand periods because the actual load is unlikely to exceed the forecast.

Q. Do you agree with AWEC that it is preferable to incentivize Schedule 90 customers to maintain a flat load vs. introducing a TOU rate?

A. Yes. PGE agrees with AWEC that it is preferable to incentivize Schedule 90 customers to maintain a flat load which PGE can plan for in our long-term power planning. This benefits all customers by reducing PGE's short-term power costs needs, which are based on fluctuating loads day-to-day or seasonally.

Q. What is your recommendation regarding implementing a mid-peak window to Schedule 90?

A. We recommend the Commission reject Staff's proposal to extend a mid-peak window to Schedule 90.

V. Load Following Credit

Q. Please summarize PGE's request regarding the Load Following Credit.

A. PGE is proposing to update the load following/integration price to 4.89 mills/kWh based on the flexibility value of a 4-hour battery in Docket LC 80, PGE's most recently acknowledged 2023 Integrated Resource Plan (IRP). The current price of 1.13 mills/kWh was set over ten years ago via a Partial Stipulation in PGE's 2014 GRC, Docket UE 262. The flexibility value was based on the costs PGE avoids for ancillary services between flat load and variable load in the day ahead, hour ahead and real-time energy markets.

Q. Do you have any corrections to make?

A. Yes. In reply testimony, PGE indicated the current price was based on outdated inputs from PGE's 2016 IRP. During a review of material to respond to a data request from Staff, PGE determined the inputs and methodology used to calculate the existing load following credit were used prior to the 2016 IRP. The current price of $1.13 per MWh was agreed to in a partial stipulation in PGE's 2014 GRC, Docket UE 262 which was approved through Order No. 13-459. The flexibility value approved is based on the costs PGE avoids for ancillary services between flat load and variable load in the day ahead, hour ahead and real-time energy markets.

Q. Please summarize Parties' rebuttal testimony regarding PGE's request concerning the Load Following Credit.

A. Staff is recommending the following: the Load Following Credit not be updated at this time and secondly, they recommend eliminating the Load Following Credit. However, Staff is amenable to continuing the credit at its current level, while continuing to investigate the credit's appropriateness in a future proceeding or in UE 430.[13] Staff maintains that if the credit is to be both continued and updated, it should be updated with a value that represents the value that Schedule 90 provides to the rest of the system. Staff also questions if the Load Following Credit benefits are not already represented in rates.[14] Staff argues that PGE has not provided a convincing rationale for why the flexibility value of a lithium-ion battery is appropriate to use as a benchmark for this benefit.[15]

CUB also does not support PGE's update to the Load Following Credit. They argue the evidence does not support PGE's argument that the flexibility value of a 4-hour battery is an appropriate analogy to quantify the benefits that the Schedule 90 customer provides to the residential customer class.[16]

AWEC supports PGE's update to the Load Following Credit because a substantial share of load following costs are allocated to Schedule 90 in the generation cost study. AWEC argues there is a high correlation between flexibility needs and peak demand. Since Schedule 90 customers with a flat load have material load during peak demand, but do not cause load following costs in these hours due to their load shape, it is appropriate to apply a load following credit.[17]

Q. Before responding to Staff's concerns, can you explain what flexibility value is?

A. In PGE's 2023 IRP, "PGE defines flexibility value as the benefits provided by resources that help meet the system's flexibility adequacy target. Flexibility adequacy needs encompass

[13] Staff/3000, Stevens/20 at 11-18.
[14] Staff/3000, Stevens/19 at 12-13.
[15] Staff/3000, Stevens/19 at 5-7.
[16] CUB/500, Tran/14 at 7-9.
[17] AWEC/400, Kaufman/14 at 12-18.

multiple operational value streams, including load following, regulation, spin, non-spin and renewable integration. (ramping and forecast error mitigation.)"[18]

Q. What value does PGE's largest customer on Schedule 90 bring to the rest of PGE's system?

A. The value PGE's largest customer on Schedule 90 brings to the rest of PGE's system is by the stability of their loads. They don't have variations in load moment to moment within the hour, thus their load does not create nor contribute to forecast error when PGE's Balancing Authority is matching the real-time load to the expected forecasted load for the hour. This in turn helps fix problems that other customers that have variations within the minute and hour otherwise cause to PGE's system if Schedule 90's load was not stable. This is the flexibility value Schedule 90 brings to PGE's system.

Q. Is the benefit represented by PGE's largest customer on Schedule 90 and the Load Following Credit already represented in rates, since Schedule 90's load profile decreases the amount of flexibility reserves needed to be purchased by PGE?

A. No. Staff's concern is unfounded. PGE's Generation Marginal Cost Study allocates costs to the customer classes based on energy and capacity. PGE removes any flexibility value in the cost study and the flexibility value is not valued across any of the customer classes. PGE recognizes the flexibility value of Schedule 90 separately.

[18] *In the Matter of Portland General Electric Company, 2023 Clean Energy Plan and Integrated Resource Plan*, Docket LC 80, PGE 2023 IRP Chapter 10 Resource economics, 10.3 Flexibility value and integration cost, at 236 (Mar. 31, 2023).

Q. Staff states that PGE has not provided a convincing rationale for why the flexibility value of a lithium-ion battery is appropriate to use as a benchmark for the Load Following Credit. Please respond.

A. It is appropriate to use the flexibility value of a 4-hour battery as a benchmark for the Load Following Credit because the flexibility value has been previously acknowledged by the Commission in LC 80, PGE's 2023 IRP. A battery does not incur fuel costs or emit CO2. It is also appropriate at this time to use the flexibility value of a 4-hour battery rather than the previous benchmark which relied on the costs PGE avoids for ancillary services between flat load and variable load in the day ahead, hour ahead and real-time energy markets because the previous benchmark is not compliant with HB 2021. Simply put, a 4-hour battery is the marginal resource that provides flexibility in PGE's system.

Q. Staff states that the load following credit "may result in cross-class subsidization" and that PGE favors "promotion of programs that shift cost between classes without clear benefit to the public."[19] Please respond.

A. The Commission-approved load following credit has existed since 2014. PGE is not asking for a new concept with the load following credit, but rather an update to the value of the load following credit. It does not result in cross-class subsidization, rather it recognizes the value provided by customers on Schedule 90 greater that 250 MWa.

Q. What do you request of the Commission?

A. We request the Commission accept PGE's proposal to update the Load Following Credit based on the flexibility value of a 4-hour battery from PGE's 2023 IRP.

[19] Staff/2300 Dlouhy-Scala/7 at 14-17.

VI. Rate Spread

Q. Please summarize PGE's Customer Impact Offset (CIO) request.

A. PGE is seeking to implement a CIO for Schedules 38, 47, and 49 at 1.5 times the proposed overall average price increase (excluding Low Income Assistance and the Public Purpose Charge) by allocating the increases to the lowest impact schedule, which is Schedule 90. The total dollars reallocated to Schedule 90 from this use of the CIO is approximately $924 thousand.

Q. Please summarize Parties' rebuttal testimony regarding PGE's Rate Spread.

A. Staff maintains its position from opening testimony which proposes the CIO be implemented the following way: a cap equal to 125% of the average increase and a floor of 89.4% of the average increase. Staff argues their proposal is reasonable because it tempers rate impacts to customers, which is necessary to mitigate the impacts of cumulative rate changes and to promote equity among the rate classes.[20]

AWEC also maintains its position from opening testimony that PGE's proposed CIO not be implemented.[21] They also argue there is no need to mitigate rate changes through caps and floors as Staff recommends.[22]

Q. How does PGE respond to Staff's proposal?

A. Staff offered no new evidence in their rebuttal testimony and simply restated the same argument they made in opening testimony that PGE should implement their rate spread proposal because the "band proposed here is not too dissimilar to the bands Staff has proposed in recent electric cases."[23]

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[20] Staff/3000, Stevens/ 9 at 15-19 and Stevens/10 at 1-3.
[21] AWEC/400, Kaufman/12 at 22-23.
[22] AWEC/400, Kaufman/13 at 16-17.
[23] Staff/3000, Stevens/10 at 3-4.

Q. Does PGE's proposal achieve Staff's objectives?

A. Yes. If Staff's concern is to mitigate the impacts of cumulative rate changes and to promote equity among the rate classes, PGE's proposed rate spread achieves that.

Q. How does PGE respond to AWEC's position that a CIO is not needed?

A. We do not agree with AWEC's position. A CIO is necessary to temper rate increases for Schedule 38, 47, and 49. The total dollars that PGE is moving from these schedules and allocating to Schedule 90 is $924 thousand, which increases Schedule 90's overall proposed increase from 4.2% to 4.5%.

Q. What is your recommendation regarding PGE's CIO?

A. We request the Commission adopt PGE's proposed CIO.

VII. Transportation Line Extension Allowance

Q. Please summarize PGE's request regarding the Transportation Line Extension Allowance (TLEA).

A. We request the approval of a permanent TLEA program that is based on existing concepts in the Fleet Partner Program but with some key modifications that will reduce any cost-shifting to non-participating customers, such as the introduction of a claw back provision that will allow PGE to recover all or part of the TLEA should a participating customer fail to meet their agreed upon load. Making the TLEA a permanent program, rather than one that can be held up by the need for additional funding requests if existing funds are reserved, will be beneficial to both participating customers and the Company.

Q. Please summarize Parties' rebuttal testimony regarding the TLEA.

A. Staff continues to refute that PGE provided sufficient justification for moving the TLEA into a permanent program based on the cost benefit analysis and disagrees with our arguments against Staff's proposed input adjustments to the cost benefit analysis.

Q. What input adjustments did Staff propose to the TLEA cost benefit analysis?

A. Staff proposed using Idaho Power Company's AURORA energy price outputs for the forward market prices because "Staff believes that Idaho Power's IRP forward market price outputs represent a more up-to-date set of data."[24] Staff also proposes updating the cost of capacity to a $228 per kW value as opposed to the $175 per kW value that we proposed in reply testimony.

Q. Why isn't it appropriate to use modeling outputs from other utilities?

A. Every utility's AURORA model differs based on the inputs and forecasts used. Our model will reflect different forward market prices than Idaho's model, even over the same time

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[24] Staff 3100, Bolton/5 at 11.

horizon, because the inputs and assumptions used by each utility can vary greatly due to a difference in base resource mix, geographic location, and calibration of scenarios within the model. We appreciate that market prices can go stale, and that Staff's goal was to provide an updated look at the market, but using Idaho's forecasted forward market prices is inappropriate due to the utility-specific modeling in the AURORA models.

Q. How do you respond to Staff's assertion that $228 per kW is the appropriate value to use for cost of capacity?

A. This value deviates greatly from the $144 per kW utilized in Benefit Cost Ratio (BCR) models used for PGE's other pilots and programs. Should there be a desire for this change, it should be done across the other programs and pilots that utilize this cost-effectiveness analysis input. While a greater generation capacity credit in this scenario does decrease the cost-effectiveness in this scenario, it would increase the cost-effectiveness in other scenarios where the key purpose of the program or pilot is to avoid procurement of generation resources. Inputs to cost-effectiveness models should be contemplated wholistically so that the cost-effectiveness of different programs and pilots can be compared.

Q. Does Staff make any additional claims about the TLEA cost-effectiveness model that you would like to clarify?

A. Yes, Staff asserts that we do not use the contracted load as the basis for establishing a BCR at or near one and as such, our point about imposing a minimum contract requirement is not persuasive. The conservative case in the model is based on contracted loads and results in a BCR of 0.94, where the alternative forecasted scenario produces a BCR of 1.23. The minimum contract requirement with the claw back provision serves as protection for non-participating ratepayers should participating customers not meet the load that their TLEA was based on, effectively mitigating any risk posed by customers over-forecasting their transportation electrification (TE) load.

Q. Is Staff's assertation that a BCR must be greater than 1 cause for concern?

A. Yes, the Commission's use of a BCR score is meant to assure that investments benefit ratepayers. A score of 1 is an accepted quantification of benefit using Commission approved methodology. Staff's assertion that the TLEA activities must score greater than 1 suggests that they believe that the current standard is flawed, but they do not give insight or rationale for a departure from Commission practice. Utilities, Energy Trust of Oregon, the Northwest Energy Efficiency Alliance, and the Regional Technical Forum all rely on BCR scoring informed by Commission practice, which establishes stability in the market among those guiding investment and activity. Staff's departure is without precedence, rationale, or guidance, and should they continue to try to hold the TLEA to a higher standard than established, it could be disruptive across several demand-side management planning and investment activities across the entities that use the Commission-approved methodology.

Q. How do customers benefit by transitioning the TLEA from a program that is addressed through the TE plan to a program that is in base rates?

A. Making the TLEA permanent gives customers stability that is not currently present in the current TLEA structure. The TE plan cycle is on a three-year basis and while mid-cycle changes can be proposed, those changes can take anywhere from four to five months to be approved. In this time, funding can run out causing customers to pause their projects, waiting for the next funding cycle. While this may appear benign at face value, it can create a planning backlog, which can cause issues for grid planning. We experienced this in prior years where the funding for Fleet Partner was fully reserved and four customers who were contemplating participation paused their plans until new funds were approved.

Q. Do you plan to adjust the TLEA over time?

A. Yes, much like the standard line extension allowances that PGE offers, the TLEA will be adjusted as the market changes and different incentive levels are appropriate. Making the TLEA a permanent program does not mean that we are taking a "set it and forget it" approach, rather it allows us to give customers stability and be more planful about grid and resource planning.

Q. What action do you request the Commission take?

A. We request the Commission approve our TLEA as proposed. A consistently available TLEA has numerous benefits for participating customers and even in a conservative scenario, the BCR is very close to 1, meaning that there is minimal risk-shifting to non-participating customers.

VIII. Load Forecast Update

Q. What is the purpose of updating the load forecast?

A. As in previous Rate Reviews, and as described in Exhibit 700, PGE updates the load forecast to 1) incorporate more current load and economic data; 2) refresh forward-looking inputs assumptions and economic outlook; and 3) incorporate the most current operational information in large customers' usage forecasts. No methodological changes have been made.

Q. What updated inputs are included in PGE's latest load forecast?

A. PGE's load forecast models are specified based on historical billing data and forecasts are estimated relying on several internal and external forecasts as inputs. The updated inputs in the updated load forecast are: The models are estimated using historical data through the July 2024 billing cycle and new connects data through March 2024. Large customer forecasts were updated to reflect the most current usage data and best-known information about changes in customer operations. The macroeconomic forecast was updated to reflect the August 2024 forecast released by Oregon's Office of Economic Analysis. The end-use driver forecasts estimated by PGE's AdopDER model were updated in August 2024 to reflect the latest market shares and refined estimation. No changes were made to the energy efficiency forecast or weather input.

Q. Please describe PGE's updated delivery forecast.

A. PGE's 2025 test year energy forecast is for energy deliveries of 22,444-gigawatt hours (GWh), on a cycle-month (billing) basis, including deliveries to customers who opted out of PGE's cost-of-service rates for direct access under Schedules 485, 489 and 689. Table 2 summarizes the GWh delivery forecast in annual percentage changes on a weather-adjusted, billing cycle basis from 2020 through 2025. Actual weather-adjusted load is included through the August 2024 billing cycle.

Table 2

Change in GWh Delivery from Preceding Year: 2020-2025

Voltage Service Class	2020	2021	2022	2023	2024 (E)	2025 (E)
Residential	4.9%	1.4%	-0.9%	-0.5%	0.8%	0.7%
Commercial	-6.8%	3.5%	0.2%	-0.2%	-0.6%	-0.6%
Industrial	6.5%	8.3%	10.3%	7.1%	8.7%	10.6%
Total	0.8%	3.8%	2.4%	1.8%	2.7%	3.4%

The growth trends described when presenting the load forecast in Exhibit 700 remain true of the updated load forecast. Residential energy deliveries are comprised of increasing customer count combined with changes in average usage per customer. Commercial energy deliveries continue to decline slowly reflecting efficiency gains in the years following 2021 which reflected an initial rebound from large-scale closures in 2020. The industrial class continues to show robust year-over-year growth. PGE Exhibit 3103 shows more detail on the updated load forecast including summary by rate schedule.

Q. How does the updated load forecast compare to the load forecast in opening testimony in Exhibit 700?

A. The 2025 test year energy deliveries forecast has increased by 0.7%. This reflects offsets across customer classes and trends in actual 2024 energy deliveries. The residential deliveries forecast has decreased by 0.1%. Customer count is expected to be higher by 1.0%, offset by 1.1% lower average usage. Commercial energy deliveries are forecasted to be 1.1% lower, reflecting the 2024 trend, a slightly lower Oregon total nonfarm employment forecast and less transportation electrification load in 2025. Industrial energy deliveries continue to grow at a rapid pace, this forecast increases the 2025 industrial energy deliveries forecast by 3.1%.

IX. Bill Design

Q. What is CUB's proposal regarding PGE's bill design?

A. CUB asserts that PGE's bill design lacks transparency. Specifically, CUB claims that PGE's bill design fails to provide customers with information about PGE's monthly charges that customers should expect, makes it impossible for customers to identify the size of rate increases, and fails to provide customers with the information necessary to make rational energy choices related to energy efficiency, rooftop and community solar, and transportation electrification.[25] As result, CUB proposes a $8 million disallowance to PGE's billing revenue requirement because "it does not provide adequate service."[26]

Q. Please describe each of the concerns CUB expresses about PGE's bill design.

A. CUB's primary critiques are summarized as follows:

1. Price per unit. PGE fails to display a single price per kWh (unit price). CUB compares this practice to gas stations or food unit prices. Further CUB states that there are regulations that prohibit misleading pricing information to entice customers.[27]
2. Ability to show how prices are changing.[28]

CUB also expresses that billing charges are critical to ensure transparent price signals and enable customers to decide whether they invest in energy efficiency, rooftop and community solar, and transportation electrification.[29] However, CUB does not directly state that PGE's bill does not accomplish those things.

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[25] CUB/400, Jenks/12, at 11-17.
[26] CUB/400, Jenks/12, at 20-21.
[27] CUB/400, Jenks/13, at 6-13.
[28] CUB/400, Jenks/13, at 14-15.
[29] CUB/400, Jenks/14, at 3-6.

Q. Please respond to CUB's concern that PGE's bill does not provide a single price per kWh unit price.

A. CUB points to gas stations and grocery stores as having visible signs with unit prices. CUB doesn't discuss the underlying differences between the businesses and their pricing. If PGE was unregulated and charged for electricity by unit sold, such as kWh, then PGE could provide a unit price on the bill. PGE's prices, however, have different billing units and in the case of Schedule 102 (Federal Columbia River Benefits Supplied by Bonneville Power Administration) is blocked and only provides a credit up to 2,000 kWh per month. The units for residential bills include dollars per month, cents per kWh, and percentage of the bill (sometimes excluding certain portions of the bill[30]).

If PGE did provide a cents/kWh figure on the bill, it would have to be calculated as the total bill divided by usage. Since not all charges are cents/kWh, this average price would vary each month without a price change. Such variance would confuse customers and create more questions. CUB acknowledges this by suggesting a summary based on types of charges.

Q. Please respond to CUB's concern that PGE's bill does not show how prices are changing.

A. PGE shows both the old and new prices for each price that changes. Again, PGE has many types of charges and PGE's bill shows specifically what prices changed.

Q. Does PGE's bill design show all prices?

A. Yes. PGE shows price, quantity, and amount for each charge. It also provides subsections and totals those subsections to arrive at the overall charges for the bill.

[30] For example, Schedule 108 Public Purpose Charge is 1.5% of the bill but excludes amounts collected via Schedule 109 Energy Efficiency Funding Adjustment.

Q. Is this really an argument about how to present the information in PGE's bill in a concise summary?

A. Yes. The detail in PGE's bill is needed to show all of the charges that stem from the various parts of PGE's tariff and any local taxes.

Q. Does PGE propose any bill design changes to address CUB's concerns?

A. Yes. PGE appreciates CUB's suggestion provided in Table 3 showing a simplified way to view the bill charges by type of charge: basic, sum of all volumetric charges, and percentage fees. PGE proposes implementing a summarized view of the bill, like CUB's suggestion, no later than end of 2025. PGE will have to make the figure more nuanced to account for the blocking in Schedule 102 with either two sets of cents per kWh prices or a footnote. It will also need to list more than one price for time-of-day customers. Due to front-end and back-end billing system changes necessary, PGE plans to get feedback on a prototype with CUB and customer focus groups in the first quarter of 2025.

Table 3

Example of Simplified Bill Summary by Bill Charge Type

Charge Type	Volumetric charge calculation	Amount
Monthly Flat Charge		$13.00
Usage Charges	18.398 cents * 487 kWh =	$89.60
Taxes and Fees		$5.43
Total		**$108.08**

Q. What do you request of the Commission regarding PGE's bill design and CUB's recommended disallowance associated with bill design?

A. First, PGE respectfully requests the Commission reject CUB's requested approximately $8.45 million disallowance associated with bill design, based on 20% of billing costs. This is a punitive and inflammatory amount given PGE's compliance with all OARs and ways in which customers can view their bill and compare rates to other programmatic service offerings.

Second, PGE requests the Commission reject CUB's proposed disallowance considering the proposed changes, which are consistent with part of CUB's request (the summarized bill table by unit) and reject the other recommendations by CUB such as a single per unit cost.

Additionally, in PGE Exhibit 2000, PGE requests approval of the proposed changes to Schedule 125 to simplify the presentation of power costs on the bill, which CUB supports.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
3101	Staff Response to PGE Data Request 25
3102	Existing vs New Transformers (2021-2024) Table
3103	PGE Load Forecast September 2024

Date: September 19, 2024

TO:
Jaki Ferchland
Portland General Electric Company
Manager, Rates & Regulatory Affairs
121 SW Salmon Street, 3WTC-0306
Portland, OR 97204

FROM: Bret Stevens, Staff

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 435 – PGE Data Request No. 25

PGE Data Request No. 25:

Refer to Staff/3000, Stevens/12 where Staff states, "Staff's long-standing position is that transformers are inappropriate to include in the cost-basis for basic charges." Please provide any and all documents, including docket number references where applicable, that document Staff's long-standing position concerning the inclusion of transformers in the cost-basis for basic charges.

OPUC Data Response No. 25:

Upon review of recent rate case testimony, Staff realized that the referenced statement above is not entirely accurate. This misstatement stemmed from a miscommunication among Staff. In discussions following the filing of this data request, Staff understands that the policy discussed in the referenced statement above likely comes from Staff policy in cases for which electronic records are no longer held. Staff did not have adequate time to access archival material in order to respond to this request. As such, in this response, Staff will only discuss Staff's position in more recent cases which can be readily cited.

Prior to this case, the most recent in-depth discussion of what cost components should be included in the calculation of a cost-based basic charge can be found in UE 283, Staff/700, Compton/11-13. This testimony was also cited in UE 319, Staff/1300, St. Brown/28. In this testimony Staff Witness Dr. George Compton stated that the basic charge should include:

> …costs inevitably incurred by each customer *individually* in being served. Examples are the meter, meter-reading and billing, the service drop between the local distribution transformer and the meter, and the distribution transformer itself, or at least a minimal share thereof in the event that the transformer can simultaneously serve more than one customer.

Applying the same method described by Dr. Compton above, Staff's estimate of the cost-based basic charge is $13.36 for single-family single-phase customers. This is calculated by summing, and dividing by 12, the marginal costs associated with the meter, meter-reading, billing, the service drop, and the local distribution transformer found in PGE/904. It then follows that even using this method Staff has proposed in the past, an increase to the basic charge is not appropriate.

Existing Transformer vs New Transformers (2021 - 2024)

of Transformers (by dwelling type)

Dwelling Type	Existing Transformer	New Transformer	Grand Total
Manufactured Homes	169		169
Multi-Family	211	890	1,101
Single-Family	1,720	3,176	4,896
Grand Total	2,100	4,066	6,166

% of Transformers (by dwelling type)

Dwelling Type	Existing Transformer	New Transformer	Grand Total
Manufactured Homes	100.00%		100.00%
Multi-Family	19.16%	80.84%	100.00%
Single-Family	35.13%	64.87%	100.00%
Grand Total	34.06%	65.94%	100.00%

UE 435

Exhibit 3103 has been retained in its native format