BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 416

Policy

PORTLAND GENERAL ELECTRIC COMPANY

Surrebuttal Testimony of

Maria Pope
Brett Sims

September 11, 2023

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I. Introduction

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

A. My name is Maria Pope, and I am President and Chief Executive Officer (CEO) of PGE.

My name is Brett Sims, and I am PGE's Vice President of Strategy, Regulation and Energy Supply. Our qualifications were previously provided in PGE Exhibit 100.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is:

- To provide further general context for PGE's general rate case (GRC) and our sur-rebuttal testimony, including additional evidence of historic changes in PGE's operating environment;
- To provide additional discussion and commitment to PGE's low-income program efforts;
- To address remaining policy items as proposed by PGE; and
- To introduce other PGE testimonies that reply to unresolved issues raised by Staff and other parties.

Q. Please provide an overview of this general rate case thus far.

A. In PGE's direct testimony, filed on February 15, 2023, we explained the key expenditures and resources necessary to continue delivering safe, reliable, secure, and affordable service to our customers. This discussion included key investments made to ensure a reliable system that also addresses customer growth and ensures resiliency in response to rapidly changing power flow dynamics and increasingly challenging extreme weather and peak demand impacts. We also explained our increased expenditures related to inflation, fuel and power purchases, vegetation management, and cyber and physical security. Our reply testimony responded to

Staff and parties' direct testimony regarding these issues, save for the sizeable number of items that parties have settled, as discussed below. We continue to note our appreciation for the efforts of OPUC Staff (Staff) and parties to date in working with PGE to resolve issues in this case through many productive settlement discussions.

Q. Please describe the settlements that PGE has entered to date related to this proceeding.

A. PGE has entered into three settlements that relate to this case, all of which were filed on August 21, 2023.

The first and third settlements related to net variable power costs (NVPC) were achieved at settlement conferences on June 13 and July 11. These settlements resolved all but two issues with the parties related to NVPC.

The second stipulation addressed multiple issues related to base rates and was achieved at settlements that occurred on June 28, August 1, August 7, and August 8. This settlement resolved key elements of PGE's revenue requirement. Notably, it included a black box settlement for many proposed rate base reductions to investments such as the Faraday Resiliency and Repowering Project, transportation electrification, and transmission and distribution. It also included a black box settlement resolving all operations and maintenance proposals made by Staff, and it resolved both cost of debt and capital structure.

Q. Does PGE anticipate any additional settlements in this case?

A. PGE, Staff and the parties have continued to work together to achieve further settlements related to rate spread and rate design, and other topics. While a number of issues remain outstanding in this case, we appreciate the good faith efforts by the many parties that have helped resolve issues via settlement. PGE's initial filing was complex, and we recognize that the price increase requested is significant relative to past requests. PGE is filing this rate case amid extraordinary transformation of our operating environment and region – including policy requirements, resource mix, market structures, customer demand and end-uses, and power flows across the system. The requests and proposals included in this case respond to this transformation. While we would welcome reasonable, well-supported settlements on all issues in this GRC, we believe that resolution of certain issues by Commission order is appropriate, and even expected in a case as complex as this one.

Q. How is the remainder of your testimony organized?

A. After this introduction, we have four sections:

- Section II – Context for this Rate Case
- Section III – Low-Income Program Efforts
- Section IV – Remaining Policy Items
- Section V – Summary and Other PGE Surrebuttal Testimony

II. Context for this Rate Case

Q. Please restate PGE's mission and strategy.

A. PGE exists to power the advancement of our communities. We energize lives, strengthen communities, and foster energy solutions that promote social, economic, and environmental progress. Together with customers, partners, and investors, we are creating a clean energy future that is accessible to all, while remaining safe, reliable, and secure. Our customers remain at the forefront of our priorities, driving us to continuously explore and innovate, deploy new technologies, simplify processes, and reduce costs as we strive to deliver exceptional value. The investments, actions and proposals reflected in this rate case are critical to fulfilling these commitments to our customers and communities.

Q. Have recent events underscored the importance of PGE's mission?

A. Yes. PGE recently experienced a new record-breaking heat event on August 16, 2023, that pushed PGE's system to a new peak net system load of 4,498 megawatts (MW). This broke the record previously set in June 2021. Before 2021, PGE's peak load record had been unbroken since the winter of 1998. We anticipate experiencing continued increases to peak load in light of extreme weather events and load growth PGE has seen in recent years. PGE's weather-adjusted load growth averaged 2.4% per year resulting in aggregate load growth of 7.3% (or 160 MWa) since 2019. This is in comparison to U.S. average load growth of 0.9% per year or 2.9% total load growth over the same timeframe.[1]

The importance of our work grows every day as our ability to provide reliable service including during times of extreme weather events grows increasingly paramount for our

[1] PGE Exhibit 1101 contains PGE weather-adjusted load growth. US average from U.S. Energy Information Administration, Retail sales of electricity, all sectors.

customers. Additionally, our work to: (1) rapidly remove greenhouse gas emissions from our system, (2) electrify the economy from transportation to homes and buildings, and (3) offer products and services that put customers in control of their energy use, is how PGE is contributing to combating the effects of climate change. We see our work as critical both because it helps the communities that we power to respond and adapt to climate change and reduce its likely impacts.

Q. How does this rate case further strengthen communities and deliver energy solutions that promote social, economic, and environmental progress?

A. The investments we have made are essential for PGE to continue providing safe, reliable, and secure power as we decarbonize. This rate case demonstrates our commitment to achieving a clean energy future through investments in non-emitting resources such as the Faraday Resiliency and Repowering Project, and implementation of key technologies that are essential to serving customers, such as the Virtual Power Plant Platform which enables the increased adoption and enhanced grid control of more distributed energy resources (DERs) and flexible loads on PGE's system.

PGE's proposals in the case also respond to the rapidly changing environment and the related challenges and opportunities of today and expectations for the future.

Q. How has the landscape of participation changed in this rate case relative to the past?

A. We have seen meaningful participation from new intervening parties representing community action and environmental justice groups in this GRC. We welcome these stakeholders in the GRC process and look forward to working with them in this case and beyond. PGE believes that their participation provides greater diversity of perspectives and a more inclusive process. These stakeholders' proposals have already influenced PGE's thinking on these topics, and we appreciate their work in this proceeding. We address their rebuttal testimony below, and in further detail in Exhibit 4100.

Q. In your direct testimony you state that the overarching driver for PGE's rate case is to maintain the ability to deliver safe, secure, reliable, and affordable power amid an uncertain and rapidly evolving environment. Can you discuss any recent events that demonstrate the uncertainty and evolving environment PGE has been facing since filing this case?

A. Yes. As noted above, PGE set a new all-time net load record on August 16, 2023, at 4,498 MW. Previous days were also close to record load levels, at 4,436 MW on August 14, and 4,353 on August 15. These high loads closely tracked record-setting heat in PGE's service territory. These high loads and temperatures broke records, and the system and market conditions they created are unusual. We have experienced more extreme temperature events, record-setting peak load events in both summer and winter, and continued volatility in market prices. These circumstances have caused significant shifts in power flows and increased stress on regional transmission facilities.

Q. How does PGE view concerns about the size of the proposed cost increase in this GRC?

A. We appreciate and recognize that many of the comments made by customers express concern regarding the magnitude and impact of this price increase, particularly in today's high inflationary environment and increasing overall cost pressures. We understand that this increase is large relative to the past, and we continue to take steps to effectively manage and reduce costs. We also share the expressed concerns about the impacts of a price increase, particularly on our most vulnerable customers and communities. That said, given the historic and transformative changes in our industry and the challenging economic situation, these cost increases are a reflection of the new circumstances of our operating environment. While we have diligently focused on managing costs, finding ways to reduce inflationary impacts, and seeking federal grants to offset expenses, we also recognize that as an essential service provider, we must continue to prudently invest in, maintain, and operate our system to ensure our service remains reliable for customers even during times of escalating costs. As Staff acknowledges in its rebuttal testimony, the level of inflation that we are seeing could not have been foreseen and that until recently, the Federal Reserve expected inflation to be "transitory."[2]

We continue to emphasize cost control to reduce impacts on all customers. In addition, PGE continues to aggressively pursue unprecedented levels of funding opportunities on behalf of our customers to help maintain affordability and in support of furthering our decarbonization goals as also discussed in our opening and reply testimonies. The funding opportunities through the Inflation Reduction Act (IRA), Infrastructure Investment and Jobs Act (IIJA) and other sources could reduce the cost impacts to customers of meeting the requirements of HB 2021 in addition to providing critical funding for transportation electrification, grid resilience, climate and wildfire adaptation and resiliency, clean energy, smart grid investment, carbon reduction, hydrogen, and expanded and advanced energy efficiency.

In concert with the pursuit of federal funding opportunities on behalf of our customers, PGE was notably the first utility in Oregon to propose and implement an income qualified bill discount (IQBD), which has been adopted by customers at a faster pace than initially projected and we plan to file an updated tariff to further increase the maximum bill discount from the existing discount levels, as discussed in the section below and in more detail in Exhibit 4100.

[2] Staff/2900, Muldoon/6 at 9-13.

This program allows us to provide targeted relief to the customers who need support most, and we are proud to be taking steps to expand these efforts.

III. Low-Income Program Efforts

Q. Please explain the need for PGE's programs for low-income customers.

A. PGE takes the needs of our low-income customers very seriously. We were proud to support House Bill 2475 (HB 2475) during the 2021 legislative session, which allowed – for the first time – the state's investor-owned utilities to provide discounts based on customer income.

In response to changes made by HB 2475, PGE was able to launch the first IQBD program in Oregon. Other utilities have followed suit, and we are pleased that regulators, stakeholders, and other interested groups have supported this important work to provide bill relief across the state. We recognize and support the need for bill discount programs and other energy assistance, as supported by the adoption of PGE's IQBD program, which shows that as of July 2023, nearly 70,000 households have been enrolled in IQBD and 60,000 active participants currently receive discounts on their bills. In the coming years, we anticipate increasing enrollment to 120,000 participants. Notably, we have prioritized simplicity and efficiency in our IQBD program. Through collaboration with the Oregon Housing and Community Services Department, we've removed a significant barrier to entry for eligible customers through the application process. We want all customers who are in need and eligible for this program to have a straightforward path to enrollment, and we have partnered with a range of organizations to promote our IQBD program.

Q. Does PGE intend to make changes to its IQBD program or other efforts to assist low-income customers?

A. Yes. As detailed in PGE Exhibit 4100, we will be increasing the maximum bill discount to 60%, more than doubling the current maximum discount of 25%, and higher than the maximum discount offered by other Oregon utilities.

Additionally, PGE intends to conduct a low-income needs assessment (LINA) in 2024, to better understand the specific requirements of the low-income customers we serve. We intend to retain a third-party to implement the LINA, and we will solicit feedback from Staff and other stakeholders as we develop the proposed scope, study components, and deliverables. We believe that the data produced by the LINA will help us improve rate design, customer offerings, and tariffs – all with the goal of increasing the accessibility and affordability of our services.

Q. Is PGE interested in continuing to evolve its low-income programs?

A. Yes. While PGE has supported low-income energy assistance programs for years, this programmatic, tariffed approach is new. We are proud of what we have accomplished so far and will continue to monitor the effectiveness, costs, and benefits of the IQBD program and other programs. We anticipate that the LINA will produce results that will allow us to revise programs to better meet low-income customers' needs, potentially as a part of a more holistic discussion of energy assistance policy more generally.

IV. Remaining Policy Items

Q. What significant policy proposals remain unresolved in this proceeding?

A. While there are multiple policy issues that have been raised by both PGE and the parties, we would like to highlight two that are of particular importance. First, the eligibility of standalone energy storage systems for cost recovery via the Renewable Resources Automatic Adjustment Clause (RAAC) has not been resolved. Second, PGE's proposed changes to its power cost adjustment mechanism, as well as other parties' competing proposals, will need to be addressed by the Commission. The PCAM reform as proposed by PGE is of particular importance to ensure system reliability and our ability to achieve clean energy transformation in an environment of more regular and increasing volatile power markets and extreme weather events.

Q. Please summarize PGE's position on energy storage.

A. Energy storage will play a crucial role in the integration and effectiveness of renewable energy resources, making our near-term investments in energy storage imperative as we strive to meet our goals to decarbonize our service territory. The consistent power supply offered by energy storage smooths energy fluctuations presented by the variabilities of wind and solar, making it a vital tool for maximizing the benefits of these clean energy resources by enhancing grid reliability and ultimately allowing for the acceleration of the transition to a cleaner and more sustainable energy future.

As such, we are continuing to support our policy position in this case that "associated energy storage" should include standalone energy storage connected at the transmission level and used to integrate and firm renewable energy resources for purposes of cost recovery through Schedule 122 (RAAC).

Q. Why should the Commission support your proposal?

A. While the "Coal to Clean" Senate Bill 1547 (SB 1547) was passed in 2016 and included the term "associated energy storage" allowing for the recovery of investments through the RAAC, the use of storage at the time was minimal. Energy storage has since evolved from an emerging technology with uncertain potential, to a demonstrated clean capacity resource. As we have gained experience with energy storage on our system, we are better positioned to understand how storage can be used to support the firming and integration of renewables by enabling us to harness the full energy value of our variable resources and dispatch that energy when our customers need it. As such, our ability to timely recover our investments in this space in the same manner as renewables will be indispensable and, we believe, consistent with the spirit of SB 1547.

Q. Is PGE alone in observing the evolution of battery storage and the need for reform in this area?

A. No. The increasing importance of energy storage is well understood throughout the industry, and policymakers and advocates are working to speed the deployment of storage. PGE is grateful for these efforts. For example, PGE appreciates recent correspondence from Renewable Northwest (RNW), supporting PGE's proposal in this GRC regarding the definition of "associated energy storage" to include standalone resources connected at the transmission-voltage level. RNW's letter is attached to this testimony as Exhibit 3101.

Q. Does PGE continue to believe that PCAM modernization is critical to enabling you to meet the decarbonization mandates in HB 2021?

A. Yes. There have been fundamental and long-lasting changes to the operation of wholesale markets that require a re-examination of this crucial regulatory policy. We have demonstrated previously that the impact of these market-based changes are driven by state policy that we fully support, but that are exacerbated by extreme weather events such as the most recent August peak-load heat event that we described previously. However, the regulatory tools needed to fulfill the promise of HB 2021 are based on Commission decisions from a previous generation and are misaligned both compared to our peer utilities with whom we compete for capital, but also misaligned to the decarbonization mandate in HB 2021. The energy transition envisioned by HB 2021 is massive in both importance and size. It is imperative that the PCAM be an enabler rather than a barrier to meeting the state's energy goals. PGE's proposal to modernize the PCAM by removing the deadband and earnings test while recognizing the most significant challenge of meeting customer load during Reliability Contingency Events (RCE) is critical today and for the future.

V. Summary

Q. Please provide your closing remarks.

A. As this GRC nears its end, we are pleased with the significant progress all parties have made in reaching reasonable settlements on a wide range of issues. We appreciate our stakeholder community's willingness to engage in good-faith discussions that led to the successful resolution of many topics. There is more to do, and important issues remain at issue in this proceeding.

All this effort stems from a single purpose: we remain focused on creating a clean energy future that is accessible to all while remaining safe, reliable, and secure. We serve a vibrant, growing region that expects us to continuously explore and innovate, deploy new technologies, simplify processes, and reduce costs as we strive to deliver exceptional value to provide the electricity that our customers rely on every day. The investments, actions and proposals reflected in this rate case are critical to fulfilling these commitments to our customers and communities.

Part of our commitment to our customers is our focus on fulfilling the promises made by HB 2021. This momentous law put PGE on the ambitious path to full decarbonization of the electricity system. An increasing number of voices question whether Oregon's 80% decarbonization goal by 2030 is achievable. However, with recognition by the Commission of necessary resources and policy changes, we firmly intend to make this historic and essential transition.

We believe that the requests and proposals included in this rate case are reasonable and respond to clear, urgent needs. Our requests and proposals support the shared imperative of providing safe, reliable, secure, and affordable electric service consistent with state decarbonization requirements. After reflecting on the detailed and thoughtful testimony of the parties and public comments submitted, we believe that the requests outlined in our filing represent what is necessary to achieve these goals. We remain a nimble, customer- and community-focused partner, and we ask the Commission to ensure we have the necessary financial strength and regulatory tools to be successful at this critical stage of our clean energy transition.

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

A. The following PGE testimony responds to unresolved issues raised by Staff and other parties:

- **Exhibit 3200 – PCAM**

  Brett Sims and Darrington Outama continue to support PGE's proposed PCAM design and further reinforce the necessity and customer benefits of advancing this mechanism at this time, and they respond to parties' rebuttal testimony regarding PGE's proposal.

- **Exhibit 3300 – Associated Storage**

  Brendan McCarthy, Darren Murtaugh, and Kristen Sheeran support PGE's proposal regarding the usage of the renewable automatic adjustment clause for standalone energy storage at the transmission level, which supports the integration of renewable energy into the grid.

- **Exhibit 3400 – AACs and Deferrals**

  Jaki Ferchland and Robert Macfarlane respond to parties' recommendations regarding the addition of earnings tests and consolidation of automatic adjustment clause (AAC) tariffs and arguments regarding PGE's request that the Commission recognize that the deferral and AAC mechanisms are separate and distinct.

- **Exhibit 3500 – Revenue Requirement**

  Greg Batzler and Jaki Ferchland address four remaining revenue requirement-related proposals made by parties including: (1) a proposal to move PGE's state tax methodology away from normalization to a flow-through method, (2) a proposal to alter how PGE calculates rate base, (3) proposals regarding fuel stock, and (4) a proposal regarding the rent expense for the World Trade Center.

- **Exhibit 3600 – Transmission and Distribution**

  Kevin Putnam and Jaki Ferchland address issues regarding expenses for routine vegetation management (RVM) and respond to proposals made by Staff to implement a balancing account with performance mechanisms for RVM.

- **Exhibit 3700 – Production**

  Brian Clark and Stefan Cristea address a proposal to reduce outside generation services expense and a new Staff proposal regarding qualifying facilities pass through within power costs.

- **Exhibit 3800 – Compensation**

  Anne Mersereau and Tamara Neitzke address Staff and CUB's proposed reductions to rate base related to wages and salaries, incentives, and employee benefits.

- **Exhibit 3900 – Insurance**

  Greg Batzler and Jean-Pierre Agnese respond to proposed decreases to insurance.

- **Exhibit 4000 – Return on Equity**

  Dr. Bente Villadsen responds to the parties' recommendations regarding PGE's return on equity.

- **Exhibit 4100 – Income Qualified Bill Discount (IQBD)**

  Sunny Radcliffe and Robert Macfarlane discuss new proposals made by Staff and other parties regarding PGE's IQBD program.

- **Exhibit 4200 – Pricing**

  Robert Macfarlane and Christopher Pleasant respond to remaining recommendations made by the parties regarding decoupling.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

Exhibit	Description
3101	Renewable Northwest Letter to PGE

RENEWABLE NORTHWEST

421 SW 6th Ave Ste 1400
Portland, OR 97204
503.223.4544
RenewableNW.org

September 7, 2023

Maria Pope
President and CEO
Portland General Electric

Re: Recovery of "Associated Energy Storage" Costs
Oregon Public Utility Commission Docket UE 416

Dear Maria:

Renewable Northwest ("RNW") is a regional non-profit organization based in Portland that advocates for the rapid, responsible decarbonization of the electricity sector. We are a member-based organization, and our members include renewable energy developers and industry, and other non-profits. We understand that Portland General Electric ("PGE") is currently seeking to include the cost of stand-alone storage in an automatic adjustment clause under 469A.120(2)(a) as "associated energy storage" in Oregon Public Utility Commission ("PUC") docket UE 416. We write today to support PGE's recovery of prudent stand-alone storage costs by means of an automatic adjustment clause.

Oregon law provides that costs associated with renewable portfolio standard ("RPS") compliance may be recovered by means of an automatic adjustment clause, a streamlined cost-recovery mechanism designed to facilitate compliance with Oregon policy. This type of automatic adjustment clause is commonly referred to as the "renewable adjustment clause" or "RAC." In 2016, as part of Oregon's nation-leading "coal-to-clean" bill, the Oregon Legislature added "costs related to associated energy storage" as recoverable under the RAC. The PUC sought to define "associated energy storage" in Docket AR 616 but later closed that docket without resolution after the Legislature once again passed a nation-leading energy policy package, HB 2021.

In Docket AR 616, RNW had initially advocated for "associated energy storage" to be limited to storage co-located with an RPS-eligible generating resource; we took that position most recently in comments submitted to the PUC in 2020. Since then, however, two major changes have occurred that lead us to advocate instead for stand-alone storage to qualify as "associated energy storage": First, storage has become nationally recognized as an essential component of an electricity grid with high penetration of renewable resources. Second, the passage of HB 2021 creates a new backdrop against which Oregon utilities will have to plan to achieve RPS compliance.

On the first point, a 2021 report by the National Renewable Energy Laboratory ("NREL") points to stand-alone storage enabling penetrations of renewable generating resources of 50% or greater. Oregon Department of Energy's 2022 Biennial Energy Report sums up the NREL report this way:

According to the National Renewable Energy Laboratory, battery storage systems with a duration of two to six hours are currently sufficient to provide reliable peaking capacity in most parts of the country until renewable penetrations exceed 25 percent. For this reason, it is common to see grid-connected battery systems reported as having a duration in this range. NREL anticipates future phases of storage deployments greater than eight-hour durations as renewable penetration levels exceed 50 percent.

This relationship -- which has become increasingly clear in recent years -- establishes that stand-alone storage is necessarily "associated" with the achievement of Oregon's 50% RPS.

On the second point, HB 2021 -- which requires Oregon utilities to eliminate greenhouse gas emissions by 2040 -- changes the planning backdrop for achieving RPS compliance. Supplying 50% renewable electricity to customers while producing zero greenhouse gas emissions suggests a particularly necessary role for storage resources in balancing renewable resources on the grid. Again, this relationship establishes that stand-alone storage is "associated" with achievement of the RPS.

Given the evolution of the overall policy landscape, technical assessments of the need for energy storage in a future with high renewable penetration, and the changing planning environment that has resulted from HB 2021, we recognize that many of our previous concerns driving that limitation are now moot. On the other hand, the combination of these same factors plus the urgency of mitigating climate change and favorable renewable resource economics all counsel in favor of a swift transition. In fact, addressing the climate emergency and building out low-cost renewables formed the policy behind the "coal-to-clean" bill that added "associated energy storage" to the RAC.

For these reasons, RNW supports inclusion of prudent stand-alone storage costs in the RAC. We appreciate your consideration of this letter and our position.

Sincerely,

Nicole Hughes
Executive Director
Renewable Northwest

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 416

Power Cost Adjustment Mechanism (PCAM)

PORTLAND GENERAL ELECTRIC COMPANY

Surrebuttal Testimony of

Brett Sims
Darrington Outama

September 11, 2023

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I. Introduction and Summary

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

A. My name is Brett Sims. My position at PGE is Vice President, Strategy, Regulation and Energy Supply. My qualifications were previously provided in PGE Exhibit 100.

My name is Dee Outama. My position at PGE is Senior Director, Energy Supply. My qualifications were previously provided in PGE Exhibit 300.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to respond to the rebuttal testimony of the Public Utility Commission of Oregon (OPUC or Commission) Staff (Staff), the Oregon Citizens' Utility Board (CUB), and the Alliance of Western Energy Consumers (AWEC) (collectively, 'the Parties' or 'Party'). The Parties continue to oppose PGE's proposed modifications to the PCAM and propose that the Commission either maintain the existing PCAM structure or make modifications that would increase the size of the deadband from its current level. While Staff, CUB, and AWEC continue to oppose PGE's proposal, NRDC/NWEC does not take a position on PGE's proposal but agrees with PGE that the Commission should reconsider the current PCAM risk allocation mechanism.[1]

Q. Do you continue to support your proposed modifications to the PCAM?

A. Yes. The Commission should modify PGE's PCAM to account for increased power cost volatility driven by climate-driven weather extremes and variability, and the rapid and unprecedented scale of energy system transformation to achieve critically important decarbonization targets. Parties' proposals to either maintain the current PCAM design or

[1] *See* NRDC-NWEC/200, Cavanagh/10-11.

worse yet, expand deadbands, are antithetical to our current and future operating environment and will only serve to further increase our risk, jeopardizing our ability to cost-effectively raise capital and invest to deliver a safe, reliable, affordable, and clean energy future for our customers and communities.

Q. How is the remainder of your testimony organized?

A. After this introduction, we have four sections:

- Section II – we respond to the arguments of Staff in their rebuttal testimony;
- Section III – we respond to the arguments of CUB in their rebuttal testimony;
- Section IV – we respond to the arguments of AWEC in their rebuttal testimony;
- Section V – we present our conclusions and recommendations to the Commission on this critical matter.

II. PGE's Response to Staff Rebuttal Testimony

Q. Staff continues to suggest that PGE is trying to modify the PCAM to perfectly insulate it against variations in power costs but reiterates that "Staff does not believe in perfect insulation from price volatility risk,…"[2] Is PGE seeking to create perfect insulation from volatility?

A. No. As we stated in our prior testimony, PGE's proposal continues to provide an effective incentive to manage power costs and does not seek to provide the company with full cost recovery of prudently incurred costs, nor insulate PGE from price volatility risk-associated actions that are not prudent. Rather, PGE's proposal seeks to align the risk profile of the company to its peers and better reflect the operating and market environment we face today and will continue to face in the future as we seek to meet the mandates of House Bill (HB) 2021.

Q. Staff connects the background of today's PCAM to the Western energy crises and suggests that the Commission must have been thinking about the creation of the PCAM as a tool to allocate risks of the volatility of that period.[3] Do you agree?

A. No. The Commission did not establish the PCAM until 2007 and first articulated principles related to it in 2005. The Western energy crises had abated by that point and the Commission ruled only on utility-filed deferred accounting requests related to the Western energy crises in 2002, and not on the design of an on-going mechanism.

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[2] Staff/3800, Dlouhy-Jent-Pleggi/13.
[3] *See Id.*/12.

Q. Why does this matter?

A. Staff suggests that because the Commission must have been thinking about the volatility of markets during the Western energy crises to inform the design of the PCAM, that any subsequent sources of volatility were effectively front of mind to the original design of the PCAM, which is simply not accurate. The current sources of supply and demand volatility due to portfolio changes that emphasize intermittent resources and extreme weather events could not have been anticipated at that time.

Q. Staff critiques PGE's contention that we compete against, on average, much larger companies for capital.[4] How do you respond?

A. Staff seems to miss the point here, which is that utilities we compete with for capital generally have PCAM mechanisms that allow for close to full recovery of all prudently incurred power cost variances, while at the same time are larger allowing them greater financial strength to better cope with the volatility PCAM mechanisms look to address. Staff indicates that because PGE created the proxy group as part of our evaluation of ROE, or because we require investment-grade credit ratings, such an evaluation is not compelling. We believe this is just the type of peer-to-peer evaluation that is compelling. Comparing PGE with those utilities with whom we compete for capital demonstrates that PGE is riskier than our peers and that we are substantially smaller than they are on average and therefore less able to deal with the resultant volatility in power costs than our peers. Further, the fact that PGE's rate base has grown since the implementation of the PCAM is irrelevant as these peer utilities have also grown substantially and, on average, are larger still than PGE. Finally, we note that the proxy group Staff uses for their evaluation of ROE is also substantially larger in size than PGE,

[4] *See* Staff/3800, Dlouhy-Jent-Pleggi/18.

averaging a market capitalization of about $18 billion compared to PGE's market capitalization of about $4.5 billion.[5] Thus, despite the higher earnings power of these peer utilities, the majority are not exposed to volatile power costs in the same way as PGE.

Q. Staff indicates a preference for using annual power cost data rather than more granular market data relied upon by PGE to demonstrate volatility.[6] Why does PGE focus on market data, and what does the annual power cost data demonstrate?

A. PGE uses market data because wholesale market conditions are the chief driver of power cost volatility. PGE at times relies on market purchases to meet portion of its customer load particularly during weather-driven load excursions. However, even the use of annualized power cost data demonstrates the recent increase in volatility. As Staff notes, in 2021 PGE's annual power cost variance was $61.6 million, and in 2022 it was $23.2 million. The combined variance for the most recent two-year period alone exceeds the cumulative variance of the eight years before 2021, further demonstrating a shift in normal operations and business risk.

Q. Staff claims that an ROE premium is not needed as demonstrated by the average power cost variance over the period from 2015 to 2021 expressed as an annualized ROE impact of 8.7 basis points at PGE's proposed 2024 rate base.[7] Do you agree with their analysis?

A. We agree that they did the math correctly but have missed the larger point we have made throughout this case that changing market and operating fundamentals driven by state policy mandates has driven power cost volatility higher relative to prior periods and is expected to continue to do so. The average annual variance from the period starting in 2015 includes periods before this fundamental change occurred and thus masks the sharp increase in

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[5] See Staff proxy group workpaper, Exhibit 3201 "PGE UE 416 Staff OT Exh 402 403 404 405 406 ROE Muldoon WP.xls".
[6] *See* Staff/3800, Dlouhy-Jent-Pleggi/11.
[7] *See Id.*/24.

volatility due to these drivers. As we just discussed above, the most recent two-year period of variance demonstrates this new regime. For that two-year period, PGE absorbed $33.2 million in 2021 and another $23.2 million in 2022 for a total of $56.4 million, or an annual average of $28.2 million, equating to roughly 65 basis points of ROE based on PGE's proposed 2024 rate base. By contrast, the cumulative variance over the eight-year period ending in 2020 was negative $5 million (or less than about $0.6 million per year or just over a single basis point of ROE) and largest single-year variance over the same period was $15 million in 2017 (35 basis points of ROE). As stated previously,[8] we don't disagree with CUB that forecasted power costs for much of the PCAM history have proven to be close to actual power costs but clearly there has been a shift in volatility recently. A higher ROE premium is indeed needed if the Commission were to maintain the current PCAM structure. However, as we stated in our prior testimony[9] we believe the better choice for customers is to modernize the PCAM structure as requested by PGE rather than to increase base rates for a higher ROE than PGE's requested authorized ROE of 9.8% in this case.

Q. Staff references CUB's opening testimony that PGE has made "doomsday assertions" that never come to fruition and that the PCAM did not lead to a credit downgrade.[10] Did CUB say that in their opening testimony?

A. No. CUB said that PGE has made arguments before that have been rejected in the past including rating agency preference for less risk. CUB did not say that we have made "doomsday assertions" in the past.

[8] *See* PGE/2800, Sims-Outama/18.
[9] *See Id.*/20.
[10] *See* Staff/3800, Dlouhy-Jent-Pleggi/6 referencing CUB/200, Jenks/18-19.

Q. Did PGE claim that rating agencies preferred less risk?

A. No. In PGE's opening testimony[11] our expert witness provided her assessment of how the rating agencies and other investor stakeholders view the specific business risk of PGE. Her conclusion is that "there are several areas in which PGE faces higher risks than the peer group of electric utilities."[12] She then goes on to describe the unique features of the current PCAM relative to peers that creates a higher risk profile for PGE.

Q. Has PGE claimed in this case either doomsday or credit downgrades being tied to the current PCAM structure?

A. No, our evaluation of the risk profile of the company relative to our peers is holistic, factual and does not rely on hyperbole.

Q. Staff believes that PGE understates the ability of batteries to reduce volatility. What was PGE's point in indicating that a four-hour stand-alone battery has a 45% effective load carrying capacity (ELCC)?

A. We sought to convey that the scale and timing of battery deployment is not expected to dampen market sources of volatility any time soon. As indicated in our most recent integrated resource plan (IRP), PGE has a significant non-emitting capacity need over the next 17 years to meet the mandates of HB 2021. And these are just PGE's needs; other utilities in the region have similarly large capacity needs. It will take time for PGE and other utilities or wholesale market participants to build or acquire the storage capacity needed to reliably meet these needs and thereby reduce their reliance on the market and the level of power cost volatility. While storage paired with renewables offers higher ELCCs, it will also take time to build out renewable resources at scale to pair with storage.

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[11] *See* PGE/1000, Liddle-Villadsen/68-70.
[12] PGE/1000, Liddle-Villadsen/68.

Q. Staff also claims that the WRAP with its seven-month forward showing period can be expected to insulate against volatility?[13] Do you agree?

A. No, at least not at this time. PGE has been a strong proponent of a resource adequacy program and has been actively involved in the development of WRAP. And while we are hopeful that an RA standard will lead to meaningful development and market growth in storage (or other non-emitting) resources to meet customer needs, it is simply too early to rely on the WRAP which has no demonstrated track record to dampen market-driven volatility any time soon. In fact, as we have demonstrated, sources of volatility have been increasing in recent years even as efforts to develop the WRAP have been progressing.

Q. Staff claims that a rolling cap is unnecessary based on the current PCAM construct and that PGE's proposal implicates a concept of intergenerational equity based on annual customers in PGE's service territory.[14] How do you respond?

A. We continue to believe that the rolling cap concept is a reasonable tool for the Commission to consider to help manage customer price fluctuations over time concurrent with providing meaningful change to the PCAM that we believe is necessary. We also disagree with Staff's definition of intergenerational equity as applicable to customers on a year-by-year basis and believe the Commission has expressed a similar definition of intergenerational equity to ours.[15] Further, as we indicated in our reply testimony,[16] the Commission could consider

[13] *See* Staff/2800, Dlouhy/13.
[14] *See* Staff/3800, Dlouhy-Jent-Pileggi/20-21.
[15] See *In the Matter of Portland General Electric Company's Application for an Accounting Order and for Order Approving Tariff Sheets Implementing Rate Reduction, Docket UM 989*, Order No. 08-487 (Sep. 30, 2008) at 66, which states: "(4) Intergenerational Equity. The Commission must balance customers' interests over time, known as intergenerational equity. When determining the period over which utilities will recover the costs of assets incurred to produce future benefits, as well as the period over which customers will receive the benefit of utility cost savings, the Commission attempts to equitably allocate those costs and benefits to customers over time **so no one generation of customers** receives an inequitable share." Emphasis added.
[16] *See* PGE/2800, Dlouhy/27.

alternative rolling cap sizes or retain flexibility to make decisions on a case-by-case basis in the future based on considerations applicable then, including competing views of intergenerational equity. We note that the Commission approved a two-year amortization of the 2021 PCAM collection and a 7-year amortization of the 2020 Wildfire and 2021 Ice Storm deferrals, respectively. Finally, we note that however the concept of intergenerational equity is defined, the concept is one of many factors that the Commission must balance in making amortization decisions. An overly rigid definition of one concept reduces the ability of the Commission to apply good judgment balancing competing interests.

III. PGE's Response to CUB's Rebuttal Testimony

Q. CUB indicates that a holistic view of the risk profile of PGE would lead to different conclusions regarding the regulatory risks of the company established through the PCAM.[17] Did PGE evaluate risks holistically before concluding that PGE faces increased risk relative to its peers?

A. Yes. PGE's Exhibit 1000 was based on a holistic evaluation of the risk profile of the company regarding our operating, policy, and regulatory environment. The conclusion that our risk profile is greater than that of our peers reflects information available regarding regulatory mechanisms (inclusive of the PCAM but also beyond it). Further, as we have demonstrated previously, it is the risks of power cost variability coupled with the misaligned (relative to most peers) nature of the Oregon PCAM structure that sets Oregon regulation apart. As we have previously demonstrated, the greater risk presented by the current PCAM structure is not expected to be episodic or transitory as was the case of prior bouts of wholesale market volatility. Simply put, absent major technological progress towards meeting customer reliability needs with decarbonized energy sources, the volatility of wholesale markets and their obvious impacts on power cost volatility will continue and even grow as we strive to meet Oregon's decarbonization policy mandates. Our commitment to meeting these mandates will not waiver, but it is imperative that the PCAM be modified to better reflect and enable these changes.

Q. CUB also provides a copy of a PGE investor relations presentation which indicates that Oregon regulation is constructive and highlights some of the regulatory policies that

[17] CUB/400, Jenks/8.

enable decarbonization such as the Renewable Automatic Adjustment Clause (RAAC).[18] Does this demonstrate that PGE's risk profile is not that dire?

A. No. The evaluation of risk is always evolving to include new information, and this case will be important to demonstrate if the trend of historically collaborative regulatory policy enabling decarbonization will continue. To be clear, we believe that Oregon regulation has been constructive in many instances and that the RAAC is a good example of enabling regulatory structures. However, there are questions about how aspects of that constructive environment, such as the RAAC, will be applied in this case both to stand-alone storage and future non-emitting generation. Additionally, the misaligned nature of the PCAM has been problematic[19] and is expected to become increasingly so as the state seeks to meet the requirements of HB 2021.

Q. CUB highlights that PGE has obtained cost recovery for major generation investment without regulatory lag since Coyote Springs (except for Faraday) and that this lowers risk to PGE relative to peers.[20] How do you respond?

A. As our expert witness described in PGE Exhibit 1000, "Regulatory policy that supports timely recovery of prudently incurred costs is essential to maintaining a stable, investment grade credit rating."[21] In isolation, timely recovery of major generation investment is helpful. However, major generation investments are a portion of the total cost of service, which includes many more items. Further, if timely recovery of major generation investment were a reasonable proxy for the regulatory risk profile overall, the historical earnings results we have

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[18] CUB/400, Jenks/9.
[19] PGE/1000, Liddle-Villadsen/12-13.
[20] CUB/400, Jenks/8.
[21] PGE/1000, Liddle-Villadsen/9.

presented previously[22] would not be so skewed towards under-earning. PGE in fact faces significant regulatory lag overall as most of our cost structure including grid related investments and most O&M costs are not subject to alternative forms of ratemaking that allow for pursuit of cost recovery outside of a GRC.

Q. CUB also continues to claim that power costs aren't that significant overall.[23] How do you respond?

A. While power costs fell as a percentage of overall revenue requirement from about 2009 to 2018, they remain the single most significant cost element of the company and have risen in the last five years. Most importantly, as we previously demonstrated, power costs are likely to continue to rise reflecting wholesale market conditions beyond PGE's control as we, and other regional market participants, seek to meet state policy mandates and maintain reliability.

Q. Relatedly, CUB also theorizes that as natural gas-fueled generation declines as a source of meeting customer energy needs power costs will invariably decline as a share of revenue as well.[24] Do you agree?

A. In part. We agree that natural gas-fueled generation will need to decline to meet the requirements of HB 2021. However, we do not agree that the replacement of natural gas generation with decarbonized energy sources will lead to a decline in the dollar value of power costs overall particularly since much of our customers' energy needs will continue to be met through market purchases. We further believe that the process of displacing natural gas energy sources with decarbonized sources of energy such as wind and solar will, absent major

[22] PGE/2800, Dlouhy/26.
[23] CUB/400, Jenks/5.
[24] *Id*.

technological advancement, lead to greater volatility of power costs irrespective of the overall level of costs.

Q. CUB also indicates that there has been a proliferation of single-issue ratemaking in Oregon.[25] Do you believe there is an important context to the establishment of these mechanisms that CUB leaves out?

A. Yes. CUB omits that the use of single-issue ratemaking tools has proliferated around the country and that the use of such tools enables a similar proliferation of policy goals and mandates. PGE's risk, relative to our peers, has not been materially reduced in Oregon through single-issue ratemaking, and the PCAM structure, with its unique features that place greater risks on the utility, is the primary driver that creates higher risks for PGE relative to other utilities.

Q. Ultimately, CUB concludes that the existing PCAM structure, with modifications to re-establish a return on equity (ROE)-based (or floating) deadband, represents a fair regulatory construct to allocate power cost variations.[26] Do you agree?

A. No. CUB's suggestion of modifying the PCAM to return to a deadband based on basis points of ROE would represent a step backward in regulatory policy and would not only fail to enable the important policy requirements of HB 2021 but could jeopardize them by creating a further gulf between the decarbonization policy mandates of the state and the PCAM policy of the state that was established more than 15 years ago.

[25] *Supra* /9.
[26] *Id.* /13.

IV. PGE's Response to AWEC's Rebuttal Testimony

Q. AWEC asserts that little has changed since their opening testimony and that the PCAM is operating as intended by the Commission.[27] Do you agree?

A. No. Throughout our testimony in this case we have demonstrated that there is a fundamental and systematic change in the operation of wholesale markets driven by decarbonization policy that increases the level of volatility of power costs beyond anything that could have been anticipated by the Commission when it established the current PCAM framework. AWEC's argument here is similar to Staff's argument that western energy crises sources of volatility were front of mind to the Commission in the design of the PCAM and therefore any subsequent source of market volatility was intended to be allocated according to the original PCAM design. In addition to being circular in nature, these arguments suggest that the PCAM was designed to operate in perpetuity as an allocator of any new source of power cost risk, even risks that were unknowable at the time of the original Commission decisions and are more substantial than those the Commission could have contemplated.

Q. AWEC says that "PGE has failed to demonstrate that any proposed changes to the PCAM will maintain the integrity of the mechanism, including but not limited to, the revenue neutrality."[28] How do you respond?

A. The integrity of the PCAM is intertwined with the market and operating environment in which the PCAM operates. PGE has set out to modify the PCAM and related principles so that it reflects changes in markets and enables changes in policy while aligning our risk profile to peers and providing a reasonable incentive to manage costs. That is, our proposal seeks to

[27] AWEC/600, Mullins/20.
[28] *Id.*

maintain the integrity of this key regulatory construct by adapting it to how the world has changed around us.

V. Summary and Conclusion

Q. Why should the Commission approve PGE's proposed PCAM when AWEC, CUB and Staff all suggest otherwise?

A. We have demonstrated that Commission action is necessary to respond to the rapidly increasing risk from power cost variances PGE faces, a risk which is driven by profound changes in fundamental supply and demand drivers that include a rapid shift to variable energy renewable resources, as well as increased frequency of extreme weather and load events, dramatic changes in Oregon energy law and policy, market constraints, and increased regional power market volatility. PGE has demonstrated that it faces much greater power cost risk now than it did in 2007 when the Commission originally designed the PCAM, as well as greater power cost risk since the passage of decarbonizing mandates in HB 2021. To ensure PGE's ability to comply with HB 2021, the PCAM must be updated to reflect industry standards by eliminating the deadband and the earnings review and addressing the unique operating challenges during high-reliability risk events and resulting costs. Parties argue that today's variability is either transitory or in line with historical experience. PGE does not find this to be accurate. Reasonable and balanced regulation demands adaptation and redesign of PGE's PCAM to respond to current and expected future conditions. Unlike the current PCAM structure or the alternatives supported by CUB and Staff, PGE's proposal best supports successfully implementing the ambitious HB 2021 decarbonization targets, while ensuring reliable service and providing appropriate incentives and clear signals to manage costs.

Q. Are there alternatives to PGE's proposed PCAM modifications that the Commission could consider?

A. Yes. First, at minimum, given the extraordinary challenges in meeting customer load reliably during periods of load excursion and extreme weather events, PGE urges the Commission to approve PGE's reliability contingency event (RCE) proposal: full recovery of prudently incurred costs during RCEs that are time-limited and triggered based on clear objective criteria as described in our earlier testimony as well as policy testimony.[29] Second, regarding the proposed revisions to the PCAM itself, the Commission could consider opening an investigatory docket to evaluate the PCAM outside of a utility rate case proceeding, which would allow for a deeper exploration of the issues including the impacts of HB 2021 policy mandates. However, we continue to believe that the underlying policy and market drivers of power cost volatility demand timely and decisive action. To that end, if the Commission opts to not rule on PGE's proposed PCAM in this rate case and instead opens an investigatory proceeding, the Commission should commit to a decision in the investigation that is both actionable (meaning it results in utility tariff compliance filings that change the structure of the PCAM) and timely (meaning the Commission should make determinations no later than the end of 2024). Finally, the Commission could consider obtaining an independent third-party to provide recommendations to the Commission as part of its investigation if it chooses to pursue that approach.

Q. Does this conclude your testimony?

A. Yes.

[29] *See* PGE/3100 (policy) for a discussion of recent peak load events.

List of Exhibits

PGE Exhibit	**Description**
3201	Staff proxy group workpaper "PGE UE 416 Staff OT Exh 402 403 404 405 406 ROE Muldoon WP.xls"

Exhibit 3201 has been retained and transmitted in its native format

Information provided in electronic format only

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 416

Associated Storage

PORTLAND GENERAL ELECTRIC COMPANY

Surrebuttal Testimony of

Kristen Sheeran
Brendan McCarthy
Darren Murtaugh

September 11, 2023

Table of Contents

I. Introduction

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

A. My name is Kristen Sheeran. I am the Senior Director of Strategy Integration and Planning at PGE. My qualifications were previously provided in PGE Exhibit 2700.

My name is Brendan McCarthy. I am Assistant General Counsel at PGE. My testimony pertains to my role at PGE in government affairs during the time of development and adoption of Senate Bill (SB) 838 (2007) and SB 1547 (2016). My qualifications appear at the end of this testimony.

My name is Darren Murtaugh. I am the Senior Manager of Grid Edge Solutions and Energy Storage at PGE. My qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to respond to rebuttal testimony provided by the Public Utility Commission of Oregon (OPUC or Commission) Staff (Staff) and the Oregon Citizens' Utility Board (CUB) (collectively referred to as the Parties) regarding PGE's proposal for the definition of "associated energy storage" as relates to Schedule 122, the Renewable Resources Automatic Adjustment Clause (RAAC, or RAC, as used by the Parties).

Q. How is the remainder of your testimony organized?

A. After this introduction, we have two sections:

- Section II: Standalone Storage as "Associated Energy Storage"
- Section III: Qualifications

II. Standalone Energy Storage as "Associated Energy Storage"

Q. Please provide an overview of PGE's proposal for the definition of "associated energy storage" for purposes of Schedule 122 (RAAC).

A. In opening testimony, PGE requested that the Commission clarify that, for purposes of cost recovery through Schedule 122 (RAAC), "associated energy storage" includes standalone energy storage that is used to integrate and firm renewable energy resources. The purpose and timing of PGE's request in this general rate case (GRC) is driven by the anticipated standalone energy storage projects resulting from PGE's 2021 request for proposals (RFP).[1] PGE sought clarification on the definition of "associated energy storage" in two previous dockets,[2] but the matter remains unresolved after more than five years have passed.

In opening testimony, Parties expressed concern that PGE's proposed definition was overly broad and could allow for any resource used to integrate renewable energy to use the RAAC. Consequently, in reply testimony, PGE clarified our proposed definition of "associated energy storage" to include only those standalone energy storage resources connected at the transmission-voltage level.[3] This clarified definition effectively limits the definition to large utility-scale energy storage resources,[4] which are used to integrate and firm utility-scale renewable resources. Exhibit 3301 provides a redline version of the Schedule 122 Tariff reflecting the proposed changes to this definition.

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[1] PGE/1300, Macfarlane-Pleasant/46 at 11-12.

[2] *In the Matter of Portland General Electric Company Draft Storage Potential Evaluation*, Docket UM 1856, and *In the Matter of Portland General Electric Company Request for a General Rate Revision,* Docket UE 335.

[3] To be clear, PGE agrees with Parties that co-located storage is "associated energy storage," and because that aspect of the definition is not in dispute, this testimony focuses only on the definition of "associated energy storage" as applied to standalone storage resources.

[4] PGE engineers estimate that nearly all batteries connected at the transmission-voltage level would be 20 MW or greater.

Q. What does PGE request of the Commission?

A. PGE respectfully requests that the Commission determine that—as used in Schedule 122—"associated energy storage" includes standalone energy storage connected at the transmission-voltage level.

Should the Commission adopt Staff's recommendation to hold a future proceeding on the holistic use of the RAAC, we still ask that the Commission allow PGE to apply the definition of "associated energy storage" stated above for purposes of PGE's 2021 RFP standalone energy storage acquisitions. Upon conclusion of the future proceeding that defines "associated energy storage," that definition would apply to future cost recovery of new energy storage resource acquisitions, as applicable.

Q. Please provide a brief summary of Staff's rebuttal testimony.

A. Staff appreciated the clarified definition PGE proposed in reply testimony.[5] However, Staff continues to recommend that the definition of "associated energy storage" be decided at a future proceeding, where the role of the RAAC in a post-House Bill (HB) 2021 world is evaluated more holistically and with the input from other stakeholders, notably PacifiCorp.[6] Staff also repeated their position that energy storage does not contribute to Renewable Portfolio Standard (RPS) compliance and that, in general, current resource acquisitions are not for near-term RPS compliance.

Q. Please provide a brief summary of CUB's rebuttal testimony.

A. CUB's primary objection to PGE's proposed inclusion of standalone storage as "associated" storage continues to be that the definition is overly broad and could therefore allow for

[5] Staff/3400, Dlouhy/5 at 13.
[6] *Id.*/6 at 5-9 and *Id.*/7 at 15-18.

virtually any energy storage resource to be eligible for cost recovery in the RAAC.[7] CUB maintains that the definition of "associated energy storage" should be storage that is physically co-located with an RPS-eligible resource that adds value to the underlying resource.[8]

Q. CUB asserts that "for the first time in Reply testimony, PGE shows its cards and demonstrates why it seeks to make this change… ."[9] How do you respond?

A. We find this allegation to be unfounded. Our opening testimony was clear regarding why PGE needs timely confirmation of the definition of "associated energy storage," stating that PGE expects to have standalone energy (battery) resources online in late 2024/early 2025.[10]

If CUB meant that we did not include the names of the projects from the 2021 RFP, Seaside and Evergreen, in opening testimony, then that is true. Those projects were not publicly announced until after we filed our opening testimony in February 2023 (Seaside was announced on April 28, 2023,[11] and Evergreen was announced on May 31, 2023[12]). Therefore, it was not until PGE provided reply testimony, filed July 21, 2023, that we could reference the names and size of these important energy storage projects.[13]

A. Defining "Associated Energy Storage"

Q. In reply testimony, PGE clarified the language for the proposed definition of "associated energy storage." How did the parties respond?

A. Although Staff notes that PGE's updated language was possibly a reasonable definition, they still do not support agreeing to recognize standalone storage at the transmission voltage level

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[7] CUB/400, Jenks/23 at 15-19.
[8] *Id.*/29 at 12-15.
[9] *Id.*/24 at 6-8.
[10] *See* PGE/1300, Macfarlane-Pleasant/46 at 11-12.
[11] PGE News Release, April 28, 2023. https://investors.portlandgeneral.com/news-releases/news-release-details/pge-bolsters-reliability-clean-energy-transition-regions-largest
[12] PGE News Release, May 31, 2023. https://portlandgeneral.com/news/pge-closes-out-2021-rfp-with-procurement-of-75-mw-battery-storage-project
[13] PGE/2700, Blosser-Sheeran/9 at 4-9.

as associated energy storage "at this time."[14] Staff also states that they do not believe the clarified definition would in fact place any effective limits on the standalone storage PGE could pursue in the RAAC.[15] Similarly, CUB argues that PGE's clarified definition would still allow virtually any energy storage resource to be eligible for the RAAC.[16]

Q. Do you agree that PGE's interpretation of standalone energy storage (being at the transmission voltage level) does not limit the scope of projects eligible for RAAC recovery?

A. No. PGE's clarified definition narrows the scope of eligible standalone energy resources to those connected to the grid at transmission-level voltage and excludes smaller standalone energy storage resources connected at the distribution-voltage level. PGE's proposed definition would effectively limit use of the RAAC for standalone energy storage to only those large utility-scale projects that integrate and firm large renewable energy resources, such as PGE-owned Wheatridge wind and Clearwater. PGE anticipates that energy storage resources connected at the transmission-voltage level would likely be those that are at least 20 MW in size.

Regarding CUB and Staff's concern that the definition would allow for RAAC treatment of anything that integrates and firms renewables (e.g., the Energy Imbalance Market, demand response, a natural gas plant, etc.) we agree with Staff that the RAAC is to apply to physical plant, and we have not and will not seek to include emitting resources that help firm and shape renewables under the RAAC.

[14] Staff/3400, Dlouhy/7 at 12-18.
[15] *Id.*/6 at 16-19 and *Id.*/8 at 8-10.
[16] CUB/400, Jenks/23 at 15-19.

Q. CUB asserts that PGE has been inconsistent regarding the definition of energy storage resources eligible for inclusion in the RAAC because PGE previously sought recovery through the RAAC for two microgrid energy storage projects. Please respond.

A. CUB's assertion that PGE is inconsistent and attempting to parse the language on a case-by-case is not an accurate restatement of either PGE's prior RAAC cost recovery applications or what we are proposing here. In this docket, PGE is seeking approval to clarify that for RAAC purposes, associated energy storage should include standalone energy storage connected at the transmission-voltage level.

In Docket No. UE 372 (UE 372), PGE sought cost recovery through the RAAC for the Beaverton Public Safety Center (BPSC) and the Anderson Readiness Center (ARC), two policy-driven, microgrid investments. While CUB is correct that in that docket, PGE argued that the behind-the-meter, storage facilities qualified for the RAAC, CUB fails to mention that these facilities were also co-located with solar energy resources. While these facilities are connected at the distribution-voltage level, they are not standalone energy storage resources.[17] UE 372 was subsequently consolidated with UE 370 (the Wheatridge RAAC), and the BPSC and ARC projects became a part of a stipulation allowing for AACs for all of UM 1856-approved storage projects.

Thus, PGE's current request to recognize within the meaning of "associated energy storage" standalone storage resources connected at transmission-voltage level is not inconsistent with its prior effort to recover for co-located energy connected at the distribution voltage level.

[17] UE 372/100, Murtaugh-Cristea/7 at 17-21 and *Id.*/18 at 1-11.

Q. CUB's proposed definition of "associated energy storage" states that the energy storage must be (1) on-site with and (2) add value to the underlying renewable energy resource. How does PGE respond?

A. Adopting CUB's proposed definition places a very nuanced and idiosyncratic set of engineering design and site location conditions on the energy storage resource to be included as "associated energy storage" in the RAAC. This will lead to energy storage resources that will often not satisfy the conditions for associated storage that should clearly qualify for inclusion in the RAAC. Specifically, under CUB's definition, in order for the storage to add value to the underlying renewable energy resource and meet the criteria of co-location, the facility's power conversion system would have to be intentionally undersized and the energy storage system placed such that it could compensate for that design choice. To accept CUB's reading, which appears to require this specific facility design, would impose conditions on the statutory language that are not apparent by the text and context of the statute; conditions for which there is no recorded legislative history. PGE reiterates that energy storage, whether standalone or co-located, provides value to renewable energy resources through the ability to firm, shape, and integrate variable renewable resources.

Q. CUB gives the example of Wheatridge as an energy storage resource that is co-located with an RPS-compliant resource and adds value by helping the RPS-compliant resource generate more renewable energy certificates (RECs).[18] Please explain how the storage at Wheatridge could potentially help generate more RECs and why this is unlikely to apply generally to qualifying storage?

[18] CUB/400, Jenks/27.

A. In the case of Wheatridge, any potential additional REC value of the storage co-located with the solar energy resources is due to the unique project design. Specifically, the Wheatridge Energy project battery storage resource is DC-coupled with the solar generation, allowing the battery to potentially capture generation that would have otherwise been clipped on the AC side due to the undersized power conversion system which cannot accommodate the full output of the solar resource. However, this benefit is not an inherent attribute of co-located storage projects, and this is not a standard design.

Q. Is the potential to increase REC generation the only benefit the Wheatridge co-located storage provides?

A. No. The storage also helps firm, shape, and integrate the intermittent solar resources at Wheatridge.

Q. Can standalone (e.g., not on-site) energy storage be "associated with" and "add value" to RPS-compliant renewable energy resources?

A. Yes. The intermittent nature of renewable energy resources necessitates the investment in energy storage resources to firm and integrate renewables and to maintain system reliability. In this way, energy storage and renewable energy resources are related, connected, and joined together operationally to achieve RPS compliance. Energy storage, whether on-site or standalone, serves the purpose of providing capacity-related functions and reliability functions, specifically supporting frequency response and contingency reserve (both enforceable reliability measures under NERC), that renewable energy resources lack, adding underlying value to renewable energy resources and enabling PGE to integrate increasing amounts of renewables into its resource mix.

With the ongoing retirement of traditional generator fleets on a regionwide basis, and replacement with intermittent renewables, the system will continue to be more susceptible to frequency events (i.e., loss of inertia). New on-demand, energy storage systems, capable of adjusting power output at a much steeper slope than conventional generation, need to be added to maintain appropriate levels of frequency regulation capability. In recent years, PGE has underperformed on frequency response and has relied heavily on the limited energy storage resources we have on hand to support this need.

Thus, standalone energy storage can in fact be both "associated with" and "add value" to renewable resources, contrary to CUB's claims.

Q. PGE previously stated in testimony that the value of energy storage does not come from its co-location but rather its ability to firm, shape, and integrate renewable resources on the grid. Did the Parties dispute PGE's argument in their rebuttal testimony?

A. No. The Parties do not address and thereby did not dispute that standalone energy storage resources can firm, shape, and integrate renewable resources and provide services that intermittent renewable energy resources lack on their own to ensure a reliable and stable power supply.

Q. Please provide examples and additional support for your assertion that energy storage is necessary for integrating renewable resources and achieving decarbonization goals.

A. The intermittent nature of renewable energy resources is well known and documented, and similarly, the need for energy storage to integrate and provide portfolio flexibility for system reliability is also highlighted in research, planning, and grid operations.[19]

[19] For examples, *See* Paul Denholm, et al. "Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035," Golden, CO: National Renewable Energy Laboratory (NREL) (2022)

In one recent example, on September 6, 2023, the Electric Reliability Council of Texas (ERCOT) declared an Energy Emergency Alert (EEA) level 2 because "[h]igh demand, lower wind generation, and the declining solar generation during sunset led to lower operating reserves on the grid and eventually contributed to lower frequency, which precipitated the emergency level 2 declaration," as described in a statement from Pablo Vegas, ERCOT president and CEO. Energy storage set an all-time record during this time period, providing over 2,170 MW during this critical time period.[20]

Figure 1 below shows the dramatic drop in frequency that forced ERCOT to make an EEA2 declaration, and Figure 2 shows the concomitant spike in power storage.

https://www.nrel.gov/docs/fy22osti/81644.pdf; NREL, Storage Futures | Energy Analysis | NREL; Nate Blair, et al. "Storage Futures Study: Key Learnings for the Coming Decades," Golden, CO: NREL (2022), https://www.nrel.gov/docs/fy22osti/81779.pdf

[20] Exhibit 3302 provides fuel mix data from ERCOT, ERCOT News Releases for the EEA Level 2 event and related news articles.

Figure 1 ERCOT Frequency on 9/6/2023

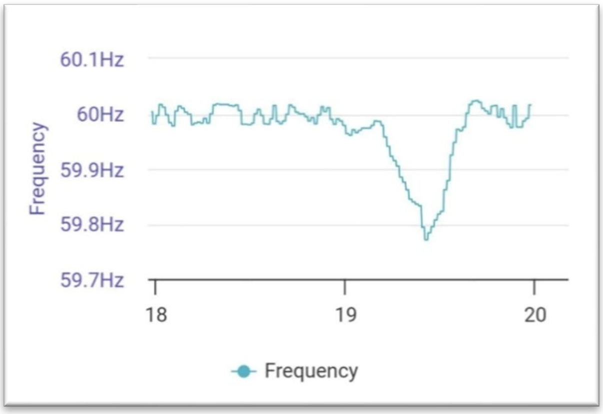
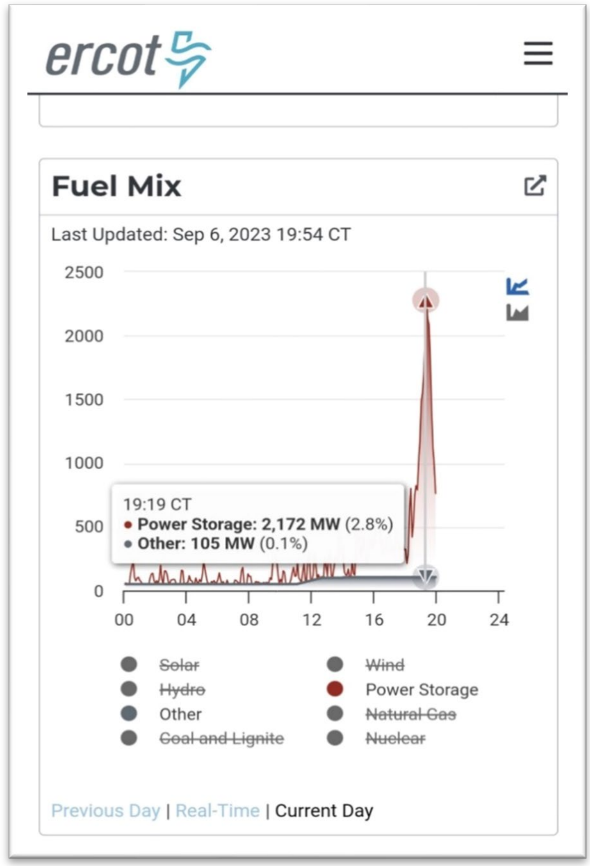


Figure 2 ERCOT Fuel Mix on 9/6/2023



Q. Have other jurisdictions recognized the importance of energy storage for integrating renewables and allowed recovery for standalone storage?

A. Yes. The state utility commissions in Virginia issued orders allowing recovery for standalone energy storage under their renewable energy tariff.[21] We would also point out that significant orders from the Federal Energy Regulatory Commission (FERC) have pushed for inclusion of electric storage resources in the regional energy markets, such as Order Nos. 841 and 2222 with requirements for regional transmission organizations (RTOs) and independent system operators (ISOs). Less than three months ago, FERC issued Order No. 898 to amend the FERC

[21] *Petition of Virginia Electric and Power Company for Approval of its 2022 RPS Development Plan*, Case No. PUR 2022-00124, Final Order (Va. State Corp. Comm'n Apr. 14, 2023) 5, 9, 10.

Uniform System of Accounts (USofA) by (1) creating new subfunctions and accounts for wind, solar, and other renewable generating assets; and (2) establishing a new functional class and accounts for energy storage assets.[22] Previously, the USofA had no accounts for many renewables.[23] The new changes will be effective on January 1, 2025. FERC made these changes in recognition of the many "technological and economic developments in the U.S. energy industry"[24] which includes growth in battery storage investments and the need for more simplified and transparent recording of energy storage given the growth in investment in the technology.

Q. Please explain at a high level how standalone energy storage resources connected at the transmission voltage level to PGE's system—such as the Evergreen and Seaside projects—will help PGE integrate increasing amounts of renewable resources needed to comply with the RPS and HB 2021.

A. Standalone energy storage provides the capacity-related functions that intermittent renewable energy resources lack and also provides reliability functions that renewables cannot—including supporting frequency response and contingency reserve (both reliability requirements enforceable by NERC). These functions that storage provides become increasingly important as the penetration of intermittent renewables increases and as traditional emitting capacity generators in the region retire. Large, standalone storage resources such as Evergreen and Seaside are essential as PGE works to supply customers with 50 percent renewable electricity to comply with the RPS, while also making progress toward HB 2021's significant emissions-reduction requirements.

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[22] Order No. 898, 183 FERC ¶ 61,205, 1 (June 29, 2023).
[23] *Id.* at 9.
[24] *Id.* at 12.

Q. How do you respond to CUB's argument in rebuttal testimony that since PGE has never sought RAAC treatment for transmission that is not physically connected to an RPS-eligible resource, PGE's effort to classify standalone storage as "associated" is not justified?[25]

A. CUB's observation is irrelevant because in this docket, we are asking the Commission to approve changes to Schedule 122 for the definition of associated energy storage—not for associated transmission. This change to Schedule 122 is necessary because PGE has specific standalone battery projects for which a determination by the Commission is requested; no such "associated" transmission project is projected. Therefore, CUB's concern that any and all transmission resources could be passed through the RAAC under PGE's proposal is unfounded.[26] On this point, it is also important to note that the RAAC allows for recovery of resources from only cost-of-service customers, so it would be difficult to separate and collect for transmission assets across all of PGE's customers through the RAAC.

Transmission and energy storage are two very different types of resources, which play different roles in supporting renewable resource additions. While CUB doubts the term "associated" was meant to have different meanings when applied to transmission versus energy storage, they ignore the inherent differences between the resources. Unlike transmission, which associates with renewable resources by transmitting the energy they produce, energy storage can "associate" with renewable resources by providing the benefits of generation, distribution or transmission, regardless of physical location. However, if it would help clarify the beneficial uses of energy storage and the way they can be used to integrate renewable generation, we would point out that just a few months ago,

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[25] CUB/400, Jenks/24.
[26] *Id.*/25.

FERC approved the Southwest Power Pool's (SPP) tariff allowing for Storage As a Transmission Only Asset (SATOA).[27]

Q. CUB expresses concern that PGE is seeking the use of the RAAC in order to decrease regulatory lag. How do you respond?

A. CUB's position ignores the fact that the purpose of the original RAAC, as adopted in SB 838 (2007), was to reduce regulatory lag for the capital-intensive, large-scale, renewable-energy projects that would be required to meet the RPS policy goals. At the time of adoption in 2007, many renewable energy projects were above market. (PGE even received an Energy Trust of Oregon incentive for Biglow Phase I.) The RAAC reduced the disincentive for investments in these capital-intensive projects. Storage facilities now occupy the same space that renewable facilities did in 2007 and should receive the same treatment.

Q. Please explain further what your understanding is regarding the motivations for developing the RAAC.

A. Ms. Sheeran and/or Mr. McCarthy were present during discussions for SB 838 (the original bill adopting the RPS and RAAC) and SB 1547 (the bill that added the language of associated energy storage in the RAAC). It is our recollection that the goal of modifying the statutory language to make the RAAC available for storage in 2016 was based on the same rationale as it was for having the RAAC available for renewable generation in 2007. That is:

1. Storage would be needed to accomplish the goals of the expanded RPS requirements;
2. Storage was a capital-intensive investment, and we should remove disincentives for investing in storage in the same manner as we had for renewable generation; and

[27] *See* 183 FERC ¶ 61,153, Order Accepting Tariff Revisions, Docket Nos ER22-2344-000, ER22-2344-001 (May 26, 2023).

3. Storage enabled renewables necessary to meet the RPS, which under SB 1547 would jump from a 25% standard to a 50% standard. There was broad recognition that storage would be necessary to achieve this standard. Not just to generate RECs but to operate the system reliably with such a significant proportion of renewable energy.

CUB's suggestion and proposed definition of associated energy storage that would limit the term to only those facility configurations that help increase REC generation is far too narrow a construction, one that would restrict cost recovery to only those actions that allow the generation of compliance instruments. However, the value of "associated energy storage" contemplated by the drafters of SB 1547 also included the value associated with firming, shaping and integrating of renewable energy to meet retail electricity needs as described in ORS 469A.120 (1). To interpret the term as CUB suggests would be to ignore statutory language that has existed since 2007.

It is important to note two additional things that occurred during the discussions between interested parties in late 2015 when the details of what became SB 1547 were being developed. First, the Oregon storage mandate of HB 2193 (2015)[28] had just been adopted and required utilities to invest in storage. This bill was technology-neutral and required utilities to analyze and "identify areas in the electric company's electric system where there may be opportunities to incentivize the value potentially derived from energy storage systems" including by using distribution and transmission data.[29] Second, the California Public Utility Commission recognized the need for storage and adopted aggressive storage goals for California utilities in October 2013, requiring 1,325 MW of storage spread across distribution, transmission and

[28] HB 2193, 78th Leg., Reg. Sess. (Or. 2015).
[29] *Id.* at 3.(A).

customer-sited projects.[30] It was understood by the participants during SB 1547 negotiations concerning the "associated storage" language that these storage mandates applied across the spectrum of possible installation scenarios and did not limit storage to only those facilities that were directly connected to renewable energy generation facilities.

Q. How does reducing regulatory lag help meet renewable energy policy goals?

A. Providing a mechanism to seek cost recovery for renewable projects at the time the project is placed into service provides cash flow and financing support when making large capital investments. Improved cash flow can support further investment to achieve renewable energy goals, while maintaining healthy balance sheet and credit ratios. Allowing cost recovery between rate cases also removes the disincentive of mid-year in-service dates, which can result from the uncertainty in project in-service dates due to supply chain or other constraints.

Q. Does the use of the RAAC, even if it reduces regulatory lag, benefit customers?

A. Yes. Customers benefit from the new renewable resources as soon as they are placed in service and deemed used and useful. A RAAC filing aligns the recovery of resource costs with the operational benefits the resource provides to customers. As previously mentioned, a healthy balance sheet and credit rating ratios provide a benefit to customers. Absent a RAAC filing, a GRC is needed for cost recovery of these large renewable resources. GRCs are significantly more complex and administratively burdensome regulatory processes than RAAC filings and include all new PGE capital investments in addition to renewable resources, along with other policy changes. For energy storage specifically, PGE sees a major benefit to customers and for process efficiency to align cost recovery with the Investment Tax Credit (ITC) treatment

[30] *In Re Rulemaking Pursuant to Assembly Bill 2514 to Consider the Adoption of Procurement Targets for Viable and Cost-Effective Energy Storage Systems*, Docket R10-12-007 (Cal. Pub. Util. Comm'n.)

and begin passing back the benefit of the tax credits to customers when the project is placed in service.

Q. CUB claims that PGE's reliance on the language in ORS 469A.120(1) regarding recovery for costs to "integrate, firm or shape renewable energy sources" to support PGE's proposal for cost recovery of energy storage is misguided because when the legislature adopted that language in 2007 it did not consider the potential application to energy storage resources.[31] How does PGE respond?

A. We will more fully address our position on the statutory interpretation in legal briefs. But we note that while it is true that the cost recovery provision in ORS 469A.120(1) was adopted in 2007, that does not mean that the legislature did not consider that language in amending ORS 469A.120(2) in 2016. CUB essentially recognizes this fact and states that "[f]orward looking laws…inherently acknowledge that changes in technology may become available that change the manner in which mandates are met."[32] Statutes speak continuously. ORS 469A.120(1) provides for cost recovery for assets used to integrate, firm or shape renewable energy resources. The fact that nine years later, the legislature saw fit to add storage technology to the specific cost recovery provision in ORS 469A.120(2) is consistent with, not contrary to, how statutes develop over time.

B. Future Proceeding

Q. Why does Staff think a future proceeding is necessary?

A. Staff lists a number of motivations to hold a future proceeding to determine the definition of associated energy storage: (1) Staff believes the Commission has the authority to determine the definition of associated energy storage and Staff is not aware of any RAAC proceedings

[31] CUB/400, Jenks/28 at 7.
[32] *Id.*/26 at 12.

where standalone energy storage has been considered;[33] (2) Staff believes that PGE relies too heavily on AACs, shifting risk to customers; (3) the RAAC was created in a pre-HB 2021 world to aid RPS, but future use of the RAAC would be for HB 2021 compliance;[34] and (4) Staff also believes a future proceeding would allow all stakeholders, including PacifiCorp, to participate in the determination of the definition of associated energy storage.[35]

Q. How does PGE respond to Staff's concern that the Commission has the authority to define associated energy storage but has not considered standalone storage in any RAAC proceedings?

A. While we will address Staff's reasoning in further detail in our legal briefs, we would still point out that we don't think Staff's points prevent what PGE is seeking: Commission approval in this GRC that PGE's Schedule 122 appropriately includes standalone energy storage at the transmission level. PGE also is not aware of a prior RAAC proceeding involving standalone storage, which is why PGE again requests guidance from the Commission in this proceeding—where the issue has been squarely presented and the record has been developed.

Q. How does PGE respond to Staff's concern that PGE relies too heavily on AACs generally, which shifts risk to customers?

A. Our colleagues respond in depth to concerns about PGE's use of AACs and claims regarding the allocation of risk in PGE Exhibit 3400 and explain why these concerns are without merit. But even if the Commission were to share Staff's concerns about AACs generally, the appropriate response would not be to postpone a decision that would provide long-needed

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[33] Staff/3400, Dlouhy/3.
[34] *Id.*/3 at 6-16.
[35] *Id.*/7 at 15-18.

clarity about the meaning of the language the legislature added to the RAAC statute seven years ago.

PGE respectfully requests that the Commission decide in this rate case that—as used in Schedule 122—"associated energy storage" includes standalone energy storage at the transmission-voltage level.

Q. How does PGE respond to Staff's concern about the use of the RAAC for RPS compliance in a post-HB 2021 world?

A. PGE previously addressed this issue in our reply testimony,[36] and we will address the issue more in legal briefs. Furthermore, as explained in the prior section of this testimony, there was broad recognition that storage would be necessary to achieve higher RPS standards. Staff's focus on REC generation ignores that RPS compliance while maintaining a reliable system is not possible without the additional integrating and firming services provided by energy storage. What we are currently seeing across the country demonstrates that storage is crucial at higher renewable generation levels.

Q. How does PGE respond to Staff's concern that a generic proceeding is appropriate because other stakeholders, particularly PacifiCorp, should be part of a proceeding to define the definition of associated energy storage?

A. PGE disagrees that it is necessary for a separate proceeding, particularly when Staff has already held a separate rulemaking[37] on this topic that included all of the utilities. Renewable Northwest (RNW) and PacifiCorp are the only two stakeholders who provided comments in

[36] PGE/2700, Sheeran—Blosser/13-16.

[37] *In the matter of Rulemaking Regarding Renewable Portfolio Standard Planning Process and Reports*, Docket No. AR 616 was closed without a decision on this issue as the Administrative Hearings Division determined that the docket's purpose was superseded by the creation of docket UM 2225 in response to HB 2021. However, UM 2225 did not address the definition of "associated energy storage" as pertains to cost recovery in the RAAC.

AR 616 that are not party to this case. However, this proceeding has allowed Staff, CUB, and AWEC the opportunity to provide input on the definition.

RNW provided a letter to update their position on the definition of "associated energy storage" in light of legislation that has occurred since AR 616.[38] In AR 616, RNW supported a definition that included co-location in part due to the tax credit eligibility.[39] With the passage of the Inflation Reduction Act (IRA), the tax credit difference between standalone and co-located energy storage is removed, eliminating one of the reasons to prefer co-located over standalone.

As for PacifiCorp, in AR 616, PacifiCorp provided input regarding the definition of "associated energy storage", [40] which was summarized in Staff's memo as follows:

> Purpose: The use of the term "associated" was purposeful and recognizes that any storage can be linked to renewable resources and that such a pairing can provide considerable benefits as increasing levels of renewables are deployed.
> Rule: It would be most appropriate to conclude that all energy storage resources are associated with renewable resources. Alternately, it would be possible to link storage to renewable resources based on the timing of the acquisition of the storage. [41]

PGE spoke with PacificCorp in July 2023 prior to submitting reply testimony in this GRC and again in August about PGE's proposed language for standalone energy storage resources as "associated energy resources" for the RAAC and Staff's recommendation for a future proceeding regarding the RAAC. On September 11, 2023, PacifiCorp sent a letter to PGE stating that they support the inclusion of standalone storage within the definition of "associated energy storage" for the RAAC.[42]

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[38] A copy of this letter is found in PGE Exhibit 3101.
[39] *See* AR 616, Comments of Renewable Northwest's (Oct. 22, 2020).
[40] Exhibit 3303, AR 616, Pacificorp Comments on Staff's Questions on Associated Energy Storage (Jun. 30, 2020).
[41] AR 616, Proposed Rule Language and Request for Comment on Associated Energy Storage (Oct. 8, 2020).
[42] *See*, Exhibit 3304.

Q. Why is it important to address the meaning of associated storage in this GRC instead of waiting for a future proceeding like Staff recommends?

A. PGE agrees there could be value in a proceeding to address the use of the RAAC in a post-HB 2021 world, however, the definition of associated storage is a topic on which PGE has sought clarification for more than five years in two separate proceedings without resolution. In rebuttal testimony, Staff identified potential additional topics to include in a future proceeding,[43] but also indicated that Staff "does not have more detail on a proceeding or proceedings to address what changes to the RAC may be appropriate." Additionally, "Staff does not have a specific timing in mind for a holistic look into the RAC."[44]

Given this uncertainty on the scope, duration, and timing of a future proceeding, PGE continues to seek a decision on the definition of "associated energy storage" from the Commission in this proceeding because clarity on this issue has implications for the actions and decisions to be made by PGE as the 2021 RFP energy storage resources are placed in-service. Namely, PGE needs to decide on how to proceed with cost recovery of the Evergreen and Seaside energy storage resources and plan for the financing impacts from cash flow dependent on the timing of those cost recovery proceedings.

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[43] Staff/3400, Dlouhy/10 at 7-9.
[44] *See,* Exhibit 3305 (OPUC response to PGE Data Request No. 67).

III. Qualifications

Q. Brendan McCarthy, please summarize your qualifications.

A. I received a Bachelor of Science degree from Pennsylvania State University in Business Management in May 1989. I also hold a Juris Doctor, with a certificate in Environment and Natural Resources, from the Northwestern School of Law of Lewis and Clark College awarded in 1996. I have been a member of the Oregon State Bar since 1996.

Prior to working for PGE, I was employed by the Oregon Legislative Assembly as a Staff Attorney and then Deputy Legislative Counsel from 1998 to 2006. In that role I was responsible for drafting legislation and frequently was asked to interpret the meaning of statutory language. I have been employed with PGE since 2006 in a number of roles including as a lobbyist and policy advocate. In 2019, I joined the Legal Department. Before joining the Legal Department, my work at PGE was not as an attorney and I did not provide legal advice or representation for PGE during this time. During my employ with PGE, I have participated in the drafting, negotiation, lobbying and implementation of some of Oregon's most significant energy and climate legislation, including: the Oregon Renewable Energy Act, aka the RPS, SB 838 (2007); the greenhouse gas reporting requirement SB 38 (2009); the emissions performance standard SB 101 (2009); the voluntary renewable energy tariff HB 4126 (2014); the storage mandate HB 2193 (2015); the increased RPS, SB 1547 (2016); Oregon's electric vehicle goals, SB 1044 (2019); and the climate legislation of HB 2021 (2021).

Q. Darren Murtaugh, please summarize your qualifications.

A. I received a Bachelor of Science degree from the University of Nevada in Electrical Engineering in December 2002. I have also received advanced training and coursework from a variety of schools and companies. I obtained my Professional Engineer license in the State of Oregon in December 2007.

In 2018 I moved to my current role as the Senior Manager of Grid Edge Solutions and Energy Storage. In this role, I oversee the development and execution of strategies to incorporate grid edge resources and energy storage for resilient electric utility system planning and operations. My previous roles at PGE include Manager of Transmission and Distribution Planning and Lead Planning Engineer. Prior to working for PGE, I worked in Transmission Operations with Sierra Pacific Power Company in Reno, Nevada.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

SCHEDULE 122
RENEWABLE RESOURCES AUTOMATIC ADJUSTMENT CLAUSE

PURPOSE

This Schedule recovers the revenue requirements of qualifying Company-owned or contracted new renewable energy resource and energy storage projects associated with renewable energy resources (including associated transmission) not otherwise included in rates. Associated energy storage includes storage used to integrate, firm, or shape renewable energy resources whether co-located or standalone energy storage connected at the transmission-voltage level. Additional new renewable and energy storage projects associated with renewable energy resources may be incorporated into this schedule as they are placed in service. This adjustment schedule is implemented as an automatic adjustment clause as provided for under ORS 757.210 and Section 13 of the Oregon Renewable Energy Act (OREA).

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all bills for Electricity Service except Schedules 76, 485, 489, 490, 491, 492, 495, 576 and 689. This schedule is not applicable to direct access customers after December 31, 2010.

ADJUSTMENT RATE

The Adjustment Rate, applicable for service on and after the effective date of this schedule are:

Schedule		Adjustment Rate	
7		0.000	¢ per kWh
15		0.000	¢ per kWh
32		0.000	¢ per kWh
38		0.000	¢ per kWh
47		0.000	¢ per kWh
49		0.000	¢ per kWh
75			
	Secondary	0.000	¢ per kWh
	Primary	0.000	¢ per kWh
	Subtransmission	0.000	¢ per kWh
83		0.000	¢ per kWh
85			
	Secondary	0.000	¢ per kWh
	Primary	0.000	¢ per kWh

SCHEDULE 122 (Continued)

ADJUSTMENT RATE (Continued)

Schedule		Adjustment Rate	
89			
	Secondary	0.000	¢ per kWh
	Primary	0.000	¢ per kWh
	Subtransmission	0.000	¢ per kWh
90			
	Primary	0.000	¢ per kWh
	Subtransmission	0.000	¢ per kWh
91		0.000	¢ per kWh
92		0.000	¢ per kWh
95		0.000	¢ per kWh

ANNUAL REVENUE REQUIREMENTS

The Annual Revenue Requirements of a qualifying project will include the fixed costs of the renewable resource or energy storage project associated with renewable energy resources and associated transmission (including return on and return of the capital costs), operation and maintenance costs, income taxes, property taxes, and other fees and costs that are applicable to the renewable resource or energy storage project associated with renewable energy resources or associated transmission. Until the dispatch benefits are included in the Annual Power Cost Update Schedule 125, the net revenue requirements of each project (fixed costs less market value of the energy produced by the renewable resource or energy storage project associated with renewable energy resources plus any power costs such as fuel, integration and wheeling costs) will be ~~deferred and~~ included in the Schedule 122 rates. By no later than April 1 of each year following the resource's on-line date, the Company will file an update to the revenue requirements of resources included in this schedule to recognize projected changes for the following calendar year. Should the final determination of a Schedule 122 filing for a new resource not allow for inclusion of its net variable power costs (NVPC) in the AUT, these will be included in the Schedule 122 revenue requirement used to set initial prices. In this circumstance, the resource's NVPC impacts will subsequently be removed from Schedule 122 prices and included in the AUT at the next available opportunity.

The Company may file a deferral request based on the Annual Revenue Requirements if an automatic adjustment clause is not established prior to the resource's on-line date, to be recovered through Schedule 122. The balancing account will accrue interest at the Commission-authorized rate for deferred accounts, and the amortization of the deferred amount will not be subject to the provisions of ORS 757.259(5).

~~DEFERRAL MECHANISM~~

~~For each calendar year that the Company anticipates that a new renewable resource or energy storage project associated with renewable energy resources will commence operation, the Company may file a deferral request the earlier of the resource online date or April 1. The deferral amount will be for the fixed revenue requirements of the resource less net dispatch benefits. For purposes of determining dispatch benefits, the forward curves used to set rates for the year under the Annual Power Cost Update will be used. The deferral will be amortized over the next calendar year in Schedule 122 unless otherwise approved by the Oregon Public Utility Commission (OPUC). The balancing account will accrue interest at the Commission-authorized rate for deferred accounts, and the amortization of the deferred amount will not be subject to the provisions of ORS 757.259(5).~~

Advice No. 23-03
Issued February 15, 2023
Brett Sims, Vice President

Effective for service
on and after March 17, 2023

SCHEDULE 122 (Continued)

TIME AND MANNER OF FILING

When the Company proposes to include a new resource under this schedule and, by no later than April 1 of each calendar year that the Company is required to update the Annual Revenue Requirements for an existing resource, the Company will file the following:

1. Revised rates under this schedule and a transmittal letter that summarizes the proposed revenue requirements and charges for both the new resource(s) and the updated revenue requirements and charges for applicable resources previously approved for recovery under this schedule. In addition, the filing will include revised income taxes and associated ratios to calculate “taxes authorized to be collected in rates” under ORS 757.268.

2. Within the Company’s Annual Power Cost Update (Schedule 125) filing, the Company will include for the following year the expected generation of resources included in this schedule and the power costs of these resources.

3. Work papers that support the calculation of revenue requirements for all applicable resources and demonstrate how the proposed prices are calculated.

With respect to a Schedule 122 rate change for the initial inclusion of the allowable costs of a new resource, and in compliance with the Commission’s findings in the proceeding(s) regarding the initial cost recovery of the new resource, the Company will file updated Schedule 122 rates by no less than 30 days prior to the rate effective date.

SPECIAL CONDITIONS

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

2. Each renewable resource project (and associated transmission) included in this adjustment schedule must be separately identified and be a new resource defined as “renewable” in the OREA.

3. The costs for projects included under this schedule will be updated annually as provided above, and will continue to be recovered under Schedule 122 until such time as the costs are included in base rates or the project is no longer in service.

4. The in-service date for the new renewable resource project or energy storage project associated with renewable energy resources or each separately identifiable projectsegment will be verified by an attestation from the Company stating that the specific renewable resource project or energy storage project associated with renewable energy resources, or project segment, has met requirements for being commercially operational and is in service.

SCHEDULE 122 (Concluded)

SPECIAL CONDITIONS (Continued)

5. If the actual costs of an eligible new resource cannot be verified by the final round of testimony in the proceeding reviewing the filing for its initial cost recovery, the Company will include in its compliance filing for initial cost recovery an update to reflect then-currentactual resource costs, or forecasted costs where appropriate. If the updated costs are lower than the projected costs in the record of the proceeding, the update will contain sufficient information to support a reduction in the proposed adjustment charges before the effective date. If updated costs are higher than the projected costs in the proceeding'srecord or if actual costs cannot be verified prior to the compliance filing, the Company mayfile for deferred accounting under the OREA to allow an opportunity for recovery of the cost differences between the projected costs in the record and the prudently incurred actual costs. For purposes of Schedule 126 (Annual Power Cost Variance Mechanism), actual NVPC will be adjusted to remove the impact of any power produced by a new renewable resource or energy storage project associated with renewable energy resources qualifying for treatment under this schedule but not otherwise included in rates. The following adjustments will be made:

    a) Actual NVPC will be increased by the value of any renewable or energy storage resource energy. The value of such energy will be determined by employing the forward curves used to set rates for the year under the Annual Power Cost Update.Actual NVPC will be reduced by applicable fuel costs and supply integration costsfor the resource.

    b) Actual NVPC will also be increased or decreased as appropriate for any other credits or charges specifically identifiable with the new renewable or energy storage resource.

6. For Schedule 122 filings made on and after April 2009, the Commission may condition approval of a proposed change in Schedule 122 charges on PGE making a filing under ORS 757.210 within six months after the Commission order approving the proposed change. Through this filing, the Company will roll into the generation component of its rates all of the costs, or a portion thereof identified by the Commission, that are being collected through the then existing Schedule 122 charges. The Commission's order for conditional approval must be based upon: (1) a finding that the costs, or a portion thereof,specified by the Commission have been collected through Schedule 122 for a reasonableperiod of years, as determined by the Commission; or (2) for good cause, as determinedby the Commission.

UTILITY DIVE

DIVE BRIEF

ERCOT forced to declare emergency conditions in extreme heat as Texas flirts with blackouts

Experts say battery resources may have kept the grid operator from declaring rolling blackouts amid low renewables output and high thermal outages.

Published Sept. 7, 2023 • Updated 6 minutes ago

Robert Walton
Senior Reporter

The Electric Reliability Council of Texas declared an Energy Emergency Alert 2 on Wednesday evening, allowing the grid operator to bring all available generation online, utilize reserve power and call on demand response. *Trong Nguyen via Getty Images*

Dive Brief:

- The Texas grid narrowly avoided blackouts Wednesday evening as cooling demand from extreme heat combined with thermal outages and low solar and wind output to force the state's grid operator into emergency operating conditions.
- The Electric Reliability Council of Texas declared an Energy Emergency Alert 2 around 7:30 p.m. local time, allowing it to bring all available generation online, utilize reserve power and call on demand response. The EEA 2 was lifted after a little more than an hour.
- The extreme heat led to a new ERCOT September peak demand record of 82,705 MW. Last September, the highest demand

recorded was 72,370 MW, the grid operator said.

Dive Insight:

ERCOT typically declares a less severe emergency, EEA 1, before turning to demand response and deploying operating reserves — but the situation moved so quickly Wednesday that the grid operator skipped that step.

“Due to low reserves and a drop in frequency, ERCOT entered directly into EEA 2. To protect the stability of the electric system, ERCOT has access to additional reserve sources only available during emergency conditions,” Pablo Vegas, ERCOT president and CEO, said in a statement.

An EEA 1 is called if operating reserves drop below 2,300 MW and are not expected to recover within 30 minutes. EEA 2 is called when operating reserves drop below 1,750 MW with similar recovery expectations. However, the grid operator indicated it was a drop in frequency that led to the EEA 2.

“High demand, lower wind generation, and the declining solar generation during sunset led to lower operating reserves on the grid and eventually contributed to lower frequency, which precipitated the emergency level 2 declaration,” Vegas said.

Grid frequency must be maintained between 60.1hz and 59.9hz, according to the grid operator.

Data from the ERCOT web site yesterday appeared to show frequency dropping to 59.8 hz, Texas energy analyst Alison Silverstein said in an email. She added that while wind output was low, it also appeared there was about 6,100 MW of thermal plants offline around 8 p.m. last night and ERCOT’s “general forecast for thermal outages anticipates 5 GW of thermal unavailable.”

That drop could be caused by a transmission line or power plant suddenly going out of service, Silverstein said. Battery resources kicked in between 7 p.m. and 8 p.m., she noted.

The EEA was likely triggered by a large power plant tripping offline, Texas energy market analyst and Stoic Energy President Doug Lewin tweeted. “Storage set an all-time record when it was needed most, almost certainly preventing rolling outages,” he added.

ERCOT posted an operational note after midnight, noting “no sudden loss of generation greater than 450 MW occurred” Wednesday.

“Thermal outages were not a factor in the ERCOT EEA last night. In fact, the thermal fleet performed extremely well, supplying more than 90% of the power Texans needed during that critical time,” Michele Richmond, executive director of Texas Competitive Power Advocates, said in an email.

Generators have been maintaining power plants, she said, taking small outages to make repairs or adjustments when anticipated demand was low or at times that other resources were expected to be available.

“This has been part of the effort to run as efficiently as possible and to be available to meet the record-breaking demand,” Richmond said. ERCOT has run the thermal fleet “exceptionally hard for an extended period of extreme heat to meet Texans’ needs. These resources will need to take time in the fall to perform required maintenance. … This means that tight conditions may occur in the fall if other resources on which ERCOT depends underperform.”

Utilities warned customers to conserve energy and brace for blackouts.

"If rotating outages are called, we anticipate these controlled outages will last for approximately 15 minutes," CPS Energy, which serves the San Antonio area, told its customers. "These situations move very quickly, and we will give you as much notice as possible but expect a short window from notice to impact."

Wednesday's EEA 2 was the first time ERCOT has called a grid emergency since February 2021, according to Bloomberg. In that instance, frigid temperatures triggered blackouts that ultimately led to an overhaul of the state's energy markets and the development of weatherization standards for energy assets.

The Texas grid has remained stable this summer despite the state experiencing several heat waves and higher demand from population growth and economic expansion.

Travis Kavulla, vice president of regulation for NRG Energy and a former Montana regulator, tweeted congratulations to ERCOT for its "nimble actions to tap all available reserves, imports, and demand response to prevent outages." He added, "the big story here continues to be just the gobsmackingly huge growth in demand for electricity."

Editor's note: This story has been updated to include comments from the Texas Competitive Power Advocates and operational data from ERCOT.

ercot

News Release

Sep 6, 2023

ERCOT Has Exited Emergency Operations, Returned to Normal Grid Conditions. No Grid-related Outages Were Necessary.

(Austin, TX) – ERCOT has exited emergency operations and returned to normal conditions.

ERCOT entered Emergency Operations this evening to maintain stability of the grid. The EEA 2 was issued due to a combination of dropping operating reserves and frequency. Frequency of the entire ERCOT grid must be maintained between 60.1hz and 59.9hz at all times. By entering EEA 2, ERCOT could utilize additional reserve resources to protect the reliability of the grid. No power outages associated with the ERCOT power grid were necessary.

"Due to low reserves and a drop in frequency, ERCOT entered directly into EEA 2. To protect the stability of the electric system, ERCOT has access to additional reserve sources only available during emergency conditions," said Pablo Vegas, ERCOT President and CEO. "High demand, lower wind generation, and the declining solar generation during sunset led to lower operating reserves on the grid and eventually contributed to lower frequency, which precipitated the emergency level 2 declaration."

Texas set a new September peak demand record today of 82,705 MW driven by extreme heat across the state.

To protect the grid, ERCOT brought all available generation online, released remaining reserves, and used demand response to lower electric demand. ERCOT also worked with out-of-state Independent System Operators (ISOs) and Market Participants to obtain additional power generation capacity. Additionally, ERCOT obtained Texas Commission on Environmental Quality (TCEQ) enforcement discretion, which allows a generator to extend its service/run-time/operations to help meet demand, if needed, to help maintain grid reliability.

If you are experiencing an outage at this time, it is not because of the ERCOT power grid, but is local in nature. Please check with your local electric provider for more information.

You can find more information on EEAs here.

Factors leading to tight grid conditions include:

- **Heat**. Continued statewide high temperatures.
- **Demand**. High demand due to the heat.
- **Solar**. Solar generation declines earlier in the evening hours before completely going offline at sunset.
- **Wind**. Wind generation was low this evening during peak demand time.

Critical Medical Needs Reminder

If you have medical needs, please contact your local electric utility and have a backup plan in case power reductions, or controlled outages, are needed later. Your local electric provider is responsible for managing the power reduction, or controlled outages, in your area.

What can You do?

You can use these use these energy-saving tips to lower your electric use during this peak demand time, if safe to do so. Simple steps such as lowering/raising your thermostat a degree or two, turning off extra lights, and not using large appliances such as washer, dryers and dishwashers, can help.

Record Peak Demand

- Today, ERCOT set a new September peak record of 82,705 MW. Last September, the highest demand recorded was 72,370 MW. That is a difference of 10,335 MW in a year.
- ERCOT set an all-time peak demand record of 85,435 MW on August 10.
- This summer ERCOT has set 10 new all-time peak demand records.

Stay Updated

- Subscribe to ERCOT EmergencyAlerts, which are automated notices only sent under emergency conditions.
- Sign up for TXANS notifications on the TXANS webpage to receive additional information.
- Download our app (available through the Apple Store or Google Play)
- Monitor current and extended conditions on our website at ERCOT.com
- Follow ERCOT on Twitter (@ERCOT_ISO), Facebook (Electric Reliability Council of Texas), and LinkedIn (ERCOT).

Consumer Assistance

###

ERCOT, the Electric Reliability Council of Texas, manages the flow of electric power to more than 26 million Texas customers, representing about 90 percent of the state's electric load. As the Independent System Operator for the region, ERCOT schedules power on an electric grid that connects 52,700+ miles of transmission lines and 1,100+ generation units, including Private Use Networks. ERCOT also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for more than 8 million premises in competitive choice areas. ERCOT is a membership-based 501(c)(4) nonprofit corporation, governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature.

Contact
ERCOT Communications

media@ercot.com

PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

June 30, 2020

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street SE, Suite 100
Salem, Oregon 97301

RE: AR 616—PacifiCorp's Comments on Staff's Questions on Associated Energy Storage

PacifiCorp d/b/a Pacific Power (PacifiCorp) respectfully submits these comments in response to the Public Utility Commission of Oregon (Commission) Staff's request for comments on June 19, 2020, in this proceeding.

1) *What was the purpose of including 'associated energy storage' in the language SB 1547? What facts or policy reasons support your position?*

The term "associated energy storage" in Senate Bill 1547, codified as ORS 469A.120, reflects the unique benefits that energy storage devices can provide to an electric utility's system as it increases reliance on renewable energy sources. The statute allows for recovery of the cost of any storage that is associated with "facilities that generate electricity from renewable energy sources." The use of the term "associated" was purposeful and recognizes that any storage can be linked to renewable resources, and that such a pairing can provide considerable benefits as increasing levels of renewables are deployed.

As systems move toward greater renewable penetration and deeper decarbonization, storage in some form will be required to replace the inherent ability of thermal resources to increment and decrement upon an automated or manual dispatch instruction. While storage could increment or decrement to support any kind of generation, ORS 469A.120's linkage of storage and renewables recognizes that development of the two must move in parallel to decarbonize and maintain system reliability. Therefore, all storage should be viewed as associated with facilities that generate electricity from renewable resources and its costs should be recoverable under ORS 469A.120.

2) *Should the administrative rules require 'associated energy storage' to be located on the site of a renewable resource? What legal or policy reasons support your position?*

No, the administrative rules should not require "associated energy storage" to be located on the site of a renewable resource. The statute does not provide any evidence that cost recovery under 469A.120 is contingent on the location of the energy storage device; there is no requirement that the device be "collocated with" or "next to" or even "near" the renewable resource. Had the legislature intended to create a locational requirement, it could have used one of those terms. "Associated" has a broader meaning that is intended to address the benefits that the energy storage provides to RPS-compliant resources, which is not linked in any way to location.

Further, any strict locational requirement would undercut the intent of the statute, which is to allow for cost recovery pursuant to ORS 469A.120 for energy storage devices that allow for more efficient integration of renewable energy sources. It is not the case that only collocated energy storage can provide such benefits. In fact, in many cases locating energy storage far from renewable energy sources is the most efficient way to speed development and integration of RPS-compliant resources. For example, siting energy storage near transmission constraints can allow development of resources throughout an entire region, whereas collocating a similarly sized storage device with a renewable resource might allow only for more efficient integration of that particular resource.

3) *How else might energy storage be connected to a renewable energy resources?*

As discussed in PacifiCorp's response to questions one and two, all storage is inherently "connected" to renewable energy resources, by nature of the benefits that storage provides as utilities deploy greater renewables. This is true regardless of the timing of a utility's acquisition of a storage resource. Like any resource, storage provides an incremental benefit to a utility's system, in effect by allowing greater and more consistent delivery of renewable generation. PacifiCorp and all of the state's other electric utilities already have portfolios that include significant renewable resources already. Flexibility of new storage resources can leverage capacity and energy available from those existing renewable resources to cover reliability gaps resulting from retiring conventional assets, and that capability should rightly be attributed to both new and existing renewable resources. This again indicates that renewable resources and storage are, in practice, associated in both planning and in operations.

Should the Commission attempt to establish a narrower definition of "associated," though, that line could theoretically be drawn at storage resources identified as part of a portfolio that includes new renewable resources. This must be the case regardless of location of those individual components so long as they contribute to the overall resource supply and the reliability of a utility's system. As a result, and at a minimum, storage resources identified and/or acquired at the same time as renewable resources should be considered "associated" with those new renewable resources. While this is a possible approach, PacifiCorp cautions that this narrower definition would inevitably leave out some storage resources that provide co-benefits with storage, regardless of the timing of the acquisition of that new storage. This outcome would be inconsistent with the statute.

Given that storage resources are uniquely suited to smooth out both the highs and lows from intermittent renewable generation that makes up the majority of projected renewable resources additions, and also further Oregon's other policies related to the reduction of emissions, it is reasonable for all storage resources to be eligible for the RAC, regardless of individual circumstances. This would in no way obviate the need for careful analysis in a company's integrated resource plan, competitive procurement, and prudent acquisition.

4) *Besides co-location, what metrics are available for determining if energy storage is associated with a renewable energy resource?*

Consistent with PacifiCorp's response to questions one and three, it would be most appropriate to conclude that all energy storage resources are associated with renewable resources. Alternately, it would be possible to link storage to renewable resources based on the timing of the acquisition of the storage.

It also may be possible to measure whether storage is associated with renewable resources based on whether a new storage resource reduces a utility's need for regulating reserves (which have traditionally been carbon-based resources), or if it reduces the utility's overall system variability (indicating that the storage is offsetting some of the inherent variability of renewables). More thought and analysis would need to be given regarding the appropriate metrics and methodologies for determining these types of benefits. If such a metric is desired, PacifiCorp suggests staff convene a technical workshop to discuss these issues.

Please contact Cathie Allen, Regulatory Affairs Manager, at (503) 813-5934 if you have any questions.

Sincerely,

Michael Wilding
Director, Net Power Costs and Regulatory Policy

PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

September 11, 2023

VIA ELECTRONIC MAIL

Portland General Electric
121 SW Salmon Street
Portland, OR 97204

RE: ORS 469A.120 and "associated energy storage"

In light of the testimony filed in Portland General Electric's (PGE) ongoing general rate proceeding (Docket No. UE 416), PacifiCorp would like to note that PacifiCorp's position has not changed since comments were filed on June 30, 2020 in Docket No. AR 616. As noted in those comments, "The statute allows for recovery of the cost of any storage that is associated with 'facilities that generate electricity from renewable energy sources.' The use of the term 'associated' was purposeful and recognizes that any storage can be linked to renewable resources, and that such a pairing can provide considerable benefits as increasing levels of renewables are deployed…Therefore, all storage should be viewed as associated with facilities that generate electricity from renewable resources and its costs should be recoverable under ORS 469A.120."[1]

This issue has been raised and PacifiCorp's position was articulated in previous proceedings. While PacifiCorp does not oppose additional workshops or investigation, this issue is ripe for resolution at this time.

Sincerely,

/s/ Matthew McVee

Matthew McVee
Vice President, Regulatory Policy and Operations

[1] *In the Matter of Rulemaking Regarding Renewable Portfolio Standard Planning Process and Reports*, Docket No. AR 616, PacifiCorp's Comments on Staff's Questions on Associated Energy Storage (June 30, 2020).

Date: September 6, 2023

TO:
JAKI FERCHLAND
PORTLAND GENERAL ELECTRIC
MANAGER, RATES & REGULATORY
121 SW SALMON ST, 3WTC-0306
PORTLAND OR 97204
pge.opuc.filings@pgn.com;

FROM: Curtis Dlouhy
Economist/Senior Utility Analyst
Utility Strategy & Integration Division

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 416 - PGE Data Request filed August 29, 2023

PGE Data Request No 67:
Reference Staff/3400, Dlouhy/10

67. Please elaborate on what Staff is envisioning for the "future proceeding" and describe in detail when Staff proposes this future proceeding should occur and the target date for a resolution of the "future proceeding."

    a. Has Staff previously recommended a proceeding or workshop occur to address the meaning of "associated storage" or the use of the RAC? If so, please identify the dockets and provide a copy of any Staff report or testimony with the recommendation.

    b. Please identify any previous or currently open proceedings concerning the meaning of associated storage and the use of the RAC for cost recovery.

    c. Are there any currently open dockets that would impact the timing of a future proceeding to address the scope of the RAC identified by Staff? If so, list all such dockets.

OPUC Response No 67:

Staff's testimony at Staff/3400, Dlouhy/9-10 stated:

> "Staff again feels the need to reiterate that Staff recommends the Commission undertake an investigation into how HB 2021 may affect implementation of the RPS and ORS 469A.120. However, at the moment, Staff still feels it most appropriate to clarify that standalone storage resources are not eligible for the RAC until a future proceeding where the RAC can be addressed more holistically."
>
> "In other proceedings and informal conversations with stakeholders, Staff has been made aware of concerns regarding how the RAC treats issues of depreciation. While Staff working on this rate case is not fully apprised of this issue, I believe that a future proceeding devoted to integrating the RAC into a post-HB 2021 landscape could help provide clarity on this issue

> and any other issues that arise. As previously stated, I view it to be incredibly important to fully flesh out the RAC's role in HB 2021 given its scale and ambition rather than make incremental changes."

Staff does not have more detail on a proceeding or proceedings to address what changes to the RAC may be appropriate.

a. Staff is not aware of any previous recommendations for a proceeding or workshop to address the meaning of "associated storage" or the use of the RAC. However, Staff also notes that the definition of "associated energy storage" was a topic of discussion in AR 616.
b. Staff notes that Staff and stakeholders in AR 616 addressed the meaning of "associated energy storage", although Staff also notes that the docket was closed before any Staff recommendation or rule language were adopted.
c. Staff does not have a specific timing in mind for a holistic look into the RAC. However, Staff is unaware of any open dockets that would affect the timing of an investigation into the RAC.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 416

Deferrals and Automatic Adjustment Clause (AAC)

PORTLAND GENERAL ELECTRIC COMPANY

Surrebuttal Testimony of

Jaki Ferchland
Robert Macfarlane

September 11, 2023

Table of Contents

I. Introduction

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

A. My name is Jaki Ferchland. I am the Manager of Revenue Requirement in Regulatory Affairs at PGE. My qualifications appear at the end of PGE Exhibit 200.

My name is Robert Macfarlane. I am the Manager of Pricing and Tariffs in Regulatory Affairs at PGE. My qualifications appear at the end of PGE Exhibit 1200.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to respond to the rebuttal testimony provided by the Public Utility Commission of Oregon (OPUC or Commission) Staff (Staff), and the Oregon Citizens' Utility Board (CUB), (collectively, Parties) with respect to automatic adjustment clauses (AACs) and the relationship between AACs and deferrals.

Q. How is the remainder of your testimony organized?

A. After this introduction, we have three sections:

- Section II – Overview and Summary
- Section III – The Proposed Earnings Test on AACs Should Be Rejected
- Section IV – Other Specific Recommendations

II. Overview and Summary

Q. Please summarize the various positions regarding AACs, deferrals, and single-issue ratemaking.

A. The topics of AACs, deferrals and trackers resulted in a number of recommendations from multiple parties in this general rate case (GRC). Table 1 below lists the issues presented in the case, the proposing party, and, where appropriate, the support or opposition of the other parties.

Table 1
Parties Issues for AACs

Recommendation	PGE	Staff	CUB
Apply an earnings test to AACs	Opposes	Proposed by	Proposed by
Delineate between AACs and deferrals	Proposed by	Opposes	Opposes
Do not require a deferral for MMAs	Proposed by	No response	No response
Allow for the consolidation of like-deferrals	Proposed by	No response	No response
Specifically apply an earnings test to Sch. 150 and 153	Opposes	Proposed by	
Consolidate Sch. 136, 137, 150, 153	Supports in part	Proposed by	
Consolidate Sch. 135 and 138	Supports	Proposed by	
Move mature pilots into base rates	Supports	Proposed by	
Move TE pilots under UM 1938 and 2003 to base rates	Supports in part	Proposed by	
Provide an annual list of all trackers	Supports		Proposed by
Sunset trackers after three years	Opposes		Proposed by
Eliminate Schedule 110	Opposes		Proposed by
Eliminate Schedule 138	Opposes		Proposed by

PGE's primary focus of this final round of testimony is to address the Parties' arguments and support for earnings tests on all AACs, with which we strongly disagree.

Q. What do you request of the Commission?

A. We request that the Commission reject the Parties' proposal to apply an earnings test to all AACs. Their proposal is being made based on sweeping statements and assumptions that are not supported by sound policy or any applicable laws. Nor does any Party provide sufficient analysis or data to support the recommendation. Furthermore, the proposal lacks sufficient design detail. Neither Party provides an explanation as to how the utility will experience "sufficient" or "reasonable" earnings under their proposal. No details as to the size and type of earnings tests have been provided, making this proposal at the very least, immature.

As such, we encourage the Commission to reject this proposal given its lack of legal basis, its absence of analytical support, and its ambiguous state and lack of structure. It should be clear to all how a significant change to the decades-long treatment of a specific cost recovery tool will impact the company's risk profile moving forward.

Additionally, we return to PGE's initial request in this case to delineate between the deferral and AAC mechanism, and we ask that the Commission recognize this difference and no longer require deferral filings for approved AACs. This process is unnecessary and inefficient. AACs already carry the requirement within statute to be reviewed at least every two years. PGE frequently works with Staff to review the expenditures within AACs and we believe that this process is sufficient without being unduly burdensome to provide for an evaluation of PGE's spending and determine its prudence.

III. The Proposed Earnings Tests on AACs Should Be Rejected

A. Response to Parties Arguments in Favor of Earnings Tests on AACs

Q. Have Staff and CUB changed their recommendations regarding their positions on the use of AACs and trackers?

A. Both Staff and CUB maintain their recommendations. While both Parties provide more than one recommendation regarding the treatment of AACs, both Parties argue in favor of placing an earnings test on all AACs. PGE strongly disagrees with this recommendation. First, we do not believe the statute supports this position, which we will address in briefs. Second, it could result in the denial of recovery of prudently incurred costs that are necessary or that the utility has been directed to incur, impacting the utility's motivation to continue engaging in the activity.

Q. Why does PGE argue that the law does not support earnings tests for AAC?

A. As mentioned in our direct testimony, PGE Exhibit 1400, and again in our reply testimony, PGE Exhibit 2900, the provision for and definition of an AAC does not exist within the deferral statute,[1] which is the statute that permits the use of earnings tests. We will discuss this further in legal briefs.

Q. Parties argue that truing up an AAC to actuals results in retroactive ratemaking and that it is the true up portion of the AAC that requires a deferral and, therefore, is subject to an earnings test. How do you respond?

[1] ORS 757.259.

A. We disagree with this interpretation of the true up, but even if we were to agree, the only reference to the AAC in the deferral statute is to state that it is <u>not</u> to be treated in the same manner as a standard deferral for the purposes of an earnings review.

Q. Has PGE been alone in this interpretation of this language in the statute?

A. No. For well over a decade, every Staff report related to deferral filings associated with AACs has included the following exact statement or something similar: "an earnings review does not apply to an automatic adjustment clause, pursuant to ORS 757.259(5)."[2] Suddenly, in 2022, without explanation, Staff began changing these reports, which is concerning.

Q. Why is it concerning that Staff would choose to revise the standard language it uses in its reports for deferrals tied to AACs?

A. Staff abruptly abandoned its longstanding position that AACs are not subject to an earnings test. Moreover, Staff never discussed or attempted to explain the reason for their change in perspective with PGE, and the timing was sudden. For example, in a report dated May 16, 2022, which was approved on the Commission's May 31, 2022 Consent Agenda, Staff's report states: "No earnings review is applicable due to the AAC."[3] Then, a week later Staff pulled a report for an AAC deferral from the June 6, 2022 Consent Agenda that stated "Earnings Review – Cost recovery associated with this deferral will not be subject to an earnings review since it would be subject to an automatic adjustment clause."[4] Staff then resubmitted an updated report stating "Earnings Review – Cost recovery associated with this deferral may be subject to an earnings review." Staff went from 10+ years of written reports, approved through Commission order, that clearly state *the law* does not permit earnings tests

[2] Exhibit 3401, Staff reports on various PGE AAC deferrals.
[3] *In the Matter of Pacificorp, dba Pacific Power, Application for Approval of Deferred Accounting for Costs and Revenues Associated with the Transportation Electrification Charge in HB 2165*, Docket UM 2224.
[4] Exhibit 3402, Staff reports for AAC deferral for PacifiCorp in Docket UM 2224.

on AACs to suddenly saying that they do. No change occurred in the AAC or deferral statutes during this period, so at a minimum Staff's reversal of position would appear to lack any legal foundation.

Q. If earnings tests on AACs are permitted, does it matter if the utility is not allowed to recover prudently incurred costs that it has been directed to make?

A. Yes. If the utility has been directed by either the Commission or the legislature to make specific investments or engage in spending in a certain way, and then the utility is later denied recovery of those required costs for reasons that are unrelated to the prudence of the asset or spend, it imposes an unfair and unworkable conflict: act as directed and face disallowances based on an earnings test or elect not to devote resources and invest as directed and face the repercussions of non-compliance.

Q. Why do the Parties argue in favor of placing an earnings test on AACs?

A. Both Staff and CUB argue that the AAC mechanism shifts risk to customers. Specifically, in their rebuttal testimony, Staff repeatedly reiterates that "timely recovery isn't risk free recovery"[5] and claims that PGE did not address this point in our reply testimony. Staff also states that "[a] utility that has a program with an AAC would have less incentive to tighten its belt if its costs were running over but would have plenty of incentive to find ways to spend leftover money on projects if a budget surplus was expected."[6] They further claim that they view "the Company's earnings to be fungible" and that if earnings are "reasonable" the utility should not be allowed to recover prudent expenses.[7]

[5] Staff/3700, Dlouhy-Muldoon-Scala-Stevens/6 at 20-22.
[6] *Id.*/13 at 4-7.
[7] *Id*. at 11-14.

CUB appears to take a binary view of risk. It is either on the shareholder in base rates, or on customers if it is in an AAC. They did not provide an explanation for shared risk. To support their view that single-issue mechanisms shift risk to customers, they cite a 2012 article in AARP that agrees with their position. Then, similar to Staff, CUB argues that "when a utility fails an earnings test it means that rates are already sufficient to allow the cost to be recovered and no further rate change is necessary."[8]

Q. Both Staff and CUB appear to say that it is okay to deny the recovery of prudently incurred expenses if the utility's earnings are already "reasonable" or "sufficient." What does this mean?

A. We don't know. Neither CUB nor Staff provided an explanation of "reasonable" or "sufficient" in this context. This significant divergence from the previously understood treatment of AACs without a clear articulation of what it will truly mean for utility earnings shows that this proposal is undeveloped, and the Commission should reject a proposal that cannot provide a clear understanding to the utility and its stakeholders of how utility earnings could be impacted.

Just last year, Staff argued that PGE should not be able to collect prudent expenses beyond 100 basis points below our authorized ROE associated with two catastrophic, emergency events where PGE was expending every effort possible to restore power to customers.[9] If this is Staff's approach to earnings when PGE is serving its customers during a catastrophic event, how can we expect Staff's definition of "reasonable" to be anything but a value that would

[8] CUB/400, Jenks/20 at 15-17.
[9] UE 394, Staff/2600, Moore-Dlouhy-Storm/15.

seek to penalize the utility when attempting to true up costs related to something like implementing Transportation Electrification (TE) programs?

Q. Staff also states that recommending an earnings test on all AACs "would not result in a refund to customers assuming that there is a prudent reason for the funding mismatch"[10] and CUB similarly states that earnings tests "can also preclude the utility for refunding money when it is underearning."[11] Does this give comfort to PGE that Staff and CUB are not seeking to reduce the utilities' authorized ROE between rate cases or cap earnings with their generic proposal?

A. No. Again, neither Party has offered their perspective of "reasonable" or "sufficient" earnings. In fact, as it related to a *refund* deferral, Staff also argued for an earnings test of 100 basis points *below* PGE's authorized ROE of 9.5%.[12] To request a refund that would pull the utility's earnings past its authorized ROE and down another 100 basis points is purely punitive. Staff's recommendation would have essentially modified PGE's authorized ROE to 8.5%.

These are the only recent data points PGE has for Staff's perspective on a "reasonable" earnings test. That is: in the instance when we need to collect dollars for prudently incurred expenses related to a catastrophic event, they recommend disallowing our recovery of anything above 8.5%, <u>and</u> in the instance of a refund of amounts in base rates they recommend a reimbursement that would reduce our ROE to 8.5%.

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10 Staff/3700, Dlouhy-Muldoon-Scala-Stevens/14 at 4-7.
11 CUB/400, Jenks/20 at 20-22.
12 UE 394, Staff/2600, Moore-Dlouhy-Storm/15.

Q. What prior positions has CUB taken on earnings related to single-issue mechanisms for PGE?

A. In Docket No. UE 394, CUB recommended that PGE's overall return on equity should be adjusted downward by five basis points for every 1% of revenue requirement held within deferrals.[13] This proposal to reduce utility earnings, regardless of financial performance or prudence, occurred last year, and yet this year they want us to believe that their goal with the proposal in this rate case is not to cap earnings or preclude the utility from the opportunity to recover its costs and earn a reasonable return on its investments.

Q. Given their prior recommendations, is it rational for PGE to conclude that both Staff and CUB seek to cap utility earnings through the use of earnings test on all AACs?

A. Yes. While they argue it is not their goal to cap earnings, the result of the proposal from Staff and CUB, given their prior treatment and recommendations regarding specific earnings test, would do just that.

Q. How does PGE respond to Staff's notion that "timely recovery isn't risk free recovery"[14] and the claim that PGE did not address Staff's position in reply testimony?

A. PGE spent multiple pages addressing Staff's position on the risks associated with an AAC. While this exact quote was not addressed, that does not mean the topic was ignored. PGE finds this specific statement to be unfounded as PGE at no point stated that it is because of the timeliness of the recovery that there should be no earnings test.

We reiterate our disagreement with Staff's position that recovering difficult-to-forecast costs through an AAC is the same as "risk free recovery." While we do not disagree that it

[13] *In the Matter of Portland General Electric Company, Request for a General Rate Revision*, Docket UE 394, CUB/100, Jenks/8 (Oct. 25, 2021).
[14] Staff/3700, Dlouhy-Muldoon-Scala-Stevens/6 at 20-22.

negates the forecast risk associated with placing the costs into base rates, this is a risk averted for both shareholders and customers alike. Furthermore, costs in an AAC must undergo a prudence review and are scrutinized for recovery in a manner that does not occur for costs forecasted for inclusion in base rates, introducing the potential risk of disallowance of costs.

In addition, many of the statutes that require the timely recovery through an AAC also contain specific language allowing for the recovery of all prudently incurred costs. We disagree with Staff's equation of the notion that legislation that does not ensure "complete recovery"[15] requires an earnings test, particularly when the law calls for the recovery of <u>all prudently</u> incurred costs.

Q. What is PGE's response to Staff's statement that a utility with a program that has an AAC doesn't have an incentive to control costs?

A. We find this statement contradictory to Staff's opening testimony where they speak to the benefits of using an AAC for pilot programs because the costs can be difficult to forecast, and the success can be uncertain. They complete their opening testimony on this topic by saying "an AAC is a useful way to ensure costs associated with these programs are fairly collected."[16] Staff is also ignoring that any costs recovered through an AAC would still be subject to a true up review to ensure only actual costs were recovered and that those costs were prudent.

Q. How does PGE respond to CUB's argument that other "independent third-parties" have found that single-issue ratemaking shifts risk to customers?

A. CUB cites an article written over a decade ago by consumer advocate AARP. As we previously discussed in reply testimony, the electric utility landscape has been evolving rapidly over the same period. The article would not be able to contemplate the drastic

[15] Staff/3700, Dlouhy-Muldoon-Scala-Stevens/10 at 1-7.
[16] Staff/2200, Dlouhy-Muldoon-Scala-Stevens/2 at 15-21.

measures that have been asked of utilities regarding climate change within the last five years, let alone the last decade. Nor does it speak to the programs and innovations that have been requested of utilities, particularly in Oregon, since 2012.

Furthermore, the report itself references numerous AACs approved for utilities across the United States, most of which do not have earnings test. The article also does not speak of the earnings test as a recommended consumer safeguard. Overall, we do not find this article to be a compelling or appropriate source for the current decision making on this topic.

Q. If the article provided by CUB is not an appropriate source, what should the Commission rely upon for its decision making in this case?

A. We recommend reviewing the minutes and transcripts of the hearings regarding the passage of the AAC language and subsequently the deferral language into the Oregon Revised Statutes.[17, 18] PGE will make its arguments regarding these documents in briefs.

Q. What views has CUB expressed generally regarding the use of single-issue rate making?

A. In direct testimony CUB discusses the use of single-issue rate making mechanisms and their support of "restoring the principal use of the general rate case format to set rates on a holistic basis." [19]In reply testimony, PGE addresses CUB's perspective by articulating the journey the utility has taken to go from the traditional generation, poles and wires utility model, to the utility of today. A few of the mandates placed on utilities over the recent years include directives regarding renewable energy adoption, wildfire mitigation, and environmental justice. The purpose of this explanation is to show that what is expected of the utility now is not what was expected of the utility over thirty years ago and that this rapid evolution has

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[17] PGE Exhibit 3403, Legislative Minutes of SB 259, 61st Leg., Reg. Sess. (Or. 1981).
[18] PGE Exhibit 3404, Legislative History of HB 2145, 64th Leg., Reg. Sess. (Or. 1987).
[19] CUB/200, Jenks/33 at 1.

demanded an otherwise steady, run-of-the-mill industry to become a landscape of innovation. Demanding the use of only general rate cases, as was done in the past, to set customer prices while also demanding a modern utility is a mismatch of concepts.

Q. Did CUB maintain the same position in its rebuttal testimony?

A. CUB somewhat softens their arguments in rebuttal testimony relative to their direct testimony by stating that they do "not inherently oppose the use of every single mechanism across PGE's system."[20] They continue to express a preference for a holistic view of utility costs and rates and do so by recommending an earnings test on all AACs.

Q. If using AACs instead of base rates results in shifting so much risk to customers, why have Staff and CUB recommended applying an earnings test to all AACs instead of simply recommending that all AACs be moved into base rates right now?

A. This would appear to be the most obvious recommendation. CUB appears more committed to a base rates-only approach than Staff. They state a preference for setting rates primarily through rate cases, they recommend a three-year sunset period on all AACs, and they speak repeatedly about the proliferation of AACs. However, in this case, they only recommend removing two AAC tariffs of the 14 AACs currently active.[21] Their recommendations are based on the argument that those two AACs have stable forecasts. They do not make any recommendations at this time for the AACs related to programs that have high forecast risk, suggesting that perhaps they do see the benefit to customers in having these particular costs outside of base rates.

Staff generally recommends moving mature programs into base rates but then specifically points to just two TE programs, which represent minimal dollars. Staff has also proposed in

[20] CUB/400, Jenks/15 at 18.
[21] They also recommend the removal of three other schedules, which are not active.

this case to place a balancing account around PGE's routine vegetation management which could allow for a refund of dollars that would otherwise remain in base rates.

We are certainly not recommending that AACs move into base rates for all the reasons we have stated. However, we do find it curious that both Staff and CUB claim putting items in base rates places the risk on the company while AACs transfer risk to customers, yet neither proposes to move all, or even most, AACs into base rates right now. Instead, they are far more focused on obtaining an earnings test on AACs to claim holistic ratemaking has been achieved.

Q. Is there an earnings test on base rates that could prevent the utility from earning above its authorized ROE?

A. No.

B. Lack of Factual Evidence to Support Earnings Tests on AACs

Q. Did any Party provide analysis or data to support their claims that risk has shifted to customers through the increased number of AACs?

A. In their direct testimony Staff provides an analysis showing the percentage growth of AACs beginning in 2010 to the percentage growth of PGE's revenue requirement also beginning in 2010. This analysis is then used to claim that AACs have "increased far more quickly"[22] than PGE's revenue requirement. In reply testimony, PGE pointed out that such an analysis based only on percentage growth is confusing and misleading. This is because its focus on percentage growth does nothing to compare the actual dollars collected through AACs to the total revenue requirement in each year, which is what shows the proportion of total revenue requirement derived from AACs. In their rebuttal testimony Staff continues to support their misleading analysis.

[22] Staff/2200, Dlouhy-Muldoon-Scala-Stevens/7 at 9-10.

Q. Staff states that they believe "it to be more appropriate to focus on percentage growth rather than year-over-year dollars."[23] Why should the Commission not rely on such an analysis?

A. Percentage growth comparisons can lead to misleading interpretations. As a simple example, if you compare the percentage growth of Company A's profits (starting at $1,000) to Company B's profits (starting at $100), a 10% growth for Company A is $100, but a 20% growth for Company B is only $20. Context matters when the starting point for each set of values is different, such as when one is very small and the other large, which skews the percentage growth comparison. Comparing actual values over time provides a clearer picture of the absolute changes and magnitudes. This is important because absolute values indicate the real impacts of changes, while percentage growth obscures these differences. This is illustrated by PGE through a simple example provided in Exhibit 3405.

Q. Please provide an explanation for your example in Exhibit 3401.

A. In this example, it can be seen that if you add $1 each year to a starting base of $100, by year 11, you will have $110 in total. This results in 10% growth over the period. If you add $1 each year to a starting base of $1,000,000, by year 11, you will have $1,000,010. This results in 0.001% growth over the period.

However, in year 1, if you compare $100 to the $1,000,000, this shows a relationship between the two values of 0.01%, and in year 11, if you compare $110 to the $1,000,010, this still shows a relationship between the two values of 0.01%.

This example illustrates the fallacy of Staff's preferred analysis. As a parallel, they are arguing that it is more appropriate to compare the 10% to the 0.001% while ignoring the

[23] Staff/3700, Dlouhy-Muldoon-Scala-Stevens/10 at 17-18.

percentages showing the relationship between the values in year 1 versus year 11, which are the same.

Q. Does PGE's focus on the absolute dollars "completely sidestep[] the concerns brought up by CUB in the public meeting regarding ADV 1453, namely that AACs are becoming a much larger piece of the overall ratemaking pie"[24]?

A. No. Staff makes this assertion as though CUB's statements at the public meeting were accurate. But they are not, which is what we showed in PGE Exhibit 2900, Chart 2. We agree that the number of AACs in existence is higher and warrants administrative efficiency. But we disagree, and have supported with data, that they are a significantly higher proportion of the "ratemaking pie."

Essentially, our analysis in PGE Exhibit 2900 shows the proportion of total revenue (aka "ratemaking pie") collected through AACs every year. Figure 1 below further confirms how PGE's analysis supports an examination of the "ratemaking pie."

Meanwhile, Staff compares growing percentages of AACs in isolation to growing percentages of total revenue requirement in isolation. That does not show the actual relationship between these values each year. We would also note that, unlike PGE's analysis, Staff's proposed approach for examining the "ratemaking pie" cannot even be presented as a pie chart – which shows different values in relationship to each other. As such, we would argue that it is actually Staff's analysis that does not properly examine CUB's statements at the public meeting.

Q. Did CUB provide any data or analysis to support their claim at the public meeting or their testimony regarding risk and the need for earnings test on AACs?

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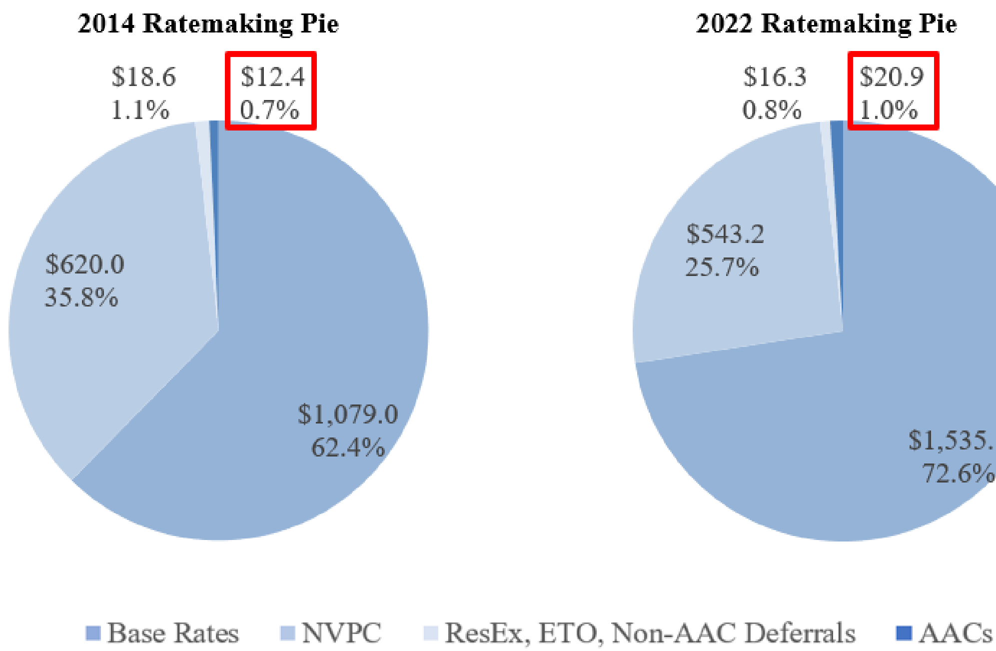
[24] Staff/3700, Dlouhy-Muldoon-Scala-Stevens/11 at 1-3.

A. No. CUB has made numerous broad and definitive statements as though they are fact, without any analysis for support.

Q. Please elaborate on the analysis PGE provided to support its position that AACs are not "a higher proportion of the ratemaking pie."

A. As stated above, in PGE Exhibit 2900, Chart 2 provided information showing the percentage that AACs comprise of total revenues over the years. Given the description used by Parties, below we provide pie charts to further illustrate PGE's analysis from reply testimony. As shown in Figure 1 below, AACs comprised 0.7% of the total "ratemaking pie" in 2014, and in 2022, AACs comprised 1.0%. We would disagree that this is a proliferation of the dollars in AACs.

Figure 1
Percentage of AACs in Overall "Ratemaking Pie" ($ millions)



Q. Please explain what the ResEx, ETO, Non-AAC Deferrals slice represents in Figure 1.

A. "ResEx" represents the Bonneville Power Administration residential exchange credit and "ETO" represents the Energy Trust of Oregon energy efficiency collection. Both items are balancing accounts that have previously been deemed as schedules that do not need a deferral filing, as these are simply pass-through items where PGE serves as the conduit between either BPA or the ETO and the customer. Non-AAC deferrals are for deferrals that are not an AAC. As such, all three of these items are not included in the AAC slice.

Q. Does PGE have any other data and analysis to support its position that risk has not shifted to customers through the increased use of AAC schedules?

A. Yes. Table 2 below shows PGE's regulated earnings over the past 10 years during the period in which the number of AACs in use grew. If CUB's and Staff's claims regarding the impact of using AACs were correct, then this chart should show consistent years of growing earnings relative to our authorized ROE. Instead, it shows that PGE is still earning less than its authorized by over 50 basis points on average within just the past five years.

Table 2
History of Authorized ROE versus Actual Regulated ROE

Year	Authorized ROE	Actual Regulated ROE
2014	9.75%	9.51%
2015	9.68%	8.18%
2016	9.60%	8.60%
2017	9.60%	7.90%
2018	9.50%	8.53%
2019	9.50%	8.44%
2020[25]	9.50%	9.70%
2021	9.50%	8.72%
2022	9.50%	9.02%
Average since 2014	**9.57%**	**8.73%**
Average since 2019	**9.50%**	**8.88%**

Q. If the amount of dollars in AACs relative to base rates had grown, is PGE agreeing that such an increase would present a shifting of risk to customers?

A. No. As we have described above and in previous testimony, moving items with a high forecast risk to a mechanism that removes that risk is a benefit to both the shareholder and the customer because a high forecast risk could result more readily in either an under-collection or overcollection. Using an AAC ensures that customers are paying no more and no less for the prudently incurred costs made by the utility to benefit customers.

C. Corrections to Parties' Misstatements of PGE's Testimony

Q. Why is PGE including a section dedicated to correcting statements made by Staff and CUB?

A. There were several critical false representations made by both parties of PGE's testimony and we felt that they were significant enough to warrant a section to correct the record.

[25] PGE's regulated ROE prior to the removal of deferrals with earnings tests was 10.40% in the filed 2020 Results of Operations report. However, PGE was not allowed to collect costs associated with the 2020 Labor Day Wildfire Emergency and PGE refunded money related to the closure the Boardman Coal Plant, driving down PGE's actual regulated ROE for 2020 to approximately 9.70%. PGE's actual ROE on its SEC income statement in 2020 was 5.96%.

Q. In their testimony, CUB claims that "PGE does not believe that the proliferation of single-issue ratemaking mechanism is a problem."[26] Is this true?

A. No. Nor is this stated anywhere in PGE's testimony. We believe that the administrative burden and the manner in which these mechanisms are handled need to be addressed. This is why we agree that PGE should provide a list to the Commission each year, and it is also why PGE dedicated its opening testimony to addressing the redundancy of filing a deferral application with every AAC.

We do believe that there is a rational reason for the increased number of AACs, and we think that it makes sense that the evolving requests by stakeholders and governing bodies of the utility have resulted also in an evolution of cost recovery from just general rate cases. Additionally, despite the number of AAC filings, we showed that the actual increase of dollars collected through AACs versus total revenue dollars collected has remained proportionately about the same. So, while the number of AACs filed has increased, there has not been a significant increase relative to total revenues.

Q. CUB restates PGE's assertions that including costs with increased forecast risk to base rates will result in higher base rate risk, but then CUB states "PGE believes assigning this risk to customers is a benefit."[27] Is CUB characterizing PGE's words correctly?

A. No. At no point does PGE refer to the usage of an AAC as "assigning risk to customers"; that is CUB's belief.

Q. They further state that "[i]t makes no sense to say that there is a significant forecast risk associated with costs when they are placed on shareholders but a benefit when they are

[26] CUB/400, Jenks/13 at 30-31.
[27] *Id*. /14 at 8-9.

placed on customers."[28] Is this a fair statement given CUB's prior inaccurate description of PGE's position?

A. Again, no. Furthermore, CUB's statement fails to recognize PGE's point that when there is a significant forecast risk and the costs are placed in base rates, extreme under- or over-collection can occur, but when the costs are placed in an AAC, that risk goes away for both the customer and the shareholder because the forecast will be trued up to actuals. We do see this as a benefit for both customers and shareholders in these circumstances.

Q. Staff states that PGE claims "that its risk profile is actually heightened through the use of AACs as opposed to putting these items into base rates given change to the utility industry."[29] Does PGE say this? If not, what does PGE say?

A. PGE does not say this in its testimony. Staff argued that allowing costs to be recovered through an AAC reduces the risk profile of the utility. PGE disagreed with this notion and highlighted that placing costs for new activities with a high forecast risk inside base rates would increase the risk present within base rates. PGE did state that "[a]llowing these costs to be in AACs does not reduce the risk profile of the utility."[30] This is not the same as saying it increases the risk to the utility.

[28] *Supra* at 12-14.
[29] Staff/3700, Dlouhy-Muldoon-Scala-Stevens/15 at 4-7.
[30] PGE/2900, Ferchland-Macfarlane/16 at 8-9.

IV. Other Specific Recommendations

A. PGE Proposals: Deferrals and AACs, Consolidation of Deferrals, MMAs

Q. What specific recommendations has PGE made regarding AACs and deferrals?

A. PGE has made a few recommendations. Most notably, we provided opening testimony requesting that the Commission recognize the AAC and deferral as two separate and distinct mechanisms. Furthermore, in our opening testimony, PGE identifies multiple deferrals that Staff required PGE to file for costs that are either already included within base rates, such as the major maintenance accrual (MMA), or do not have an associated amortization filing, such as the Multnomah County Business Income Tax (MCBIT). In addition to this, upon learning of Staff's recommendation to consolidate like-tariffs, PGE requested that the Commission support the consolidation of like-deferrals.

Q. How have Staff and CUB responded to PGE's request to delineate between AACs and deferrals?

A. Both Parties have opposed PGE's recommendations and claim that a true-up constitutes retroactive ratemaking and that it therefore legally requires a deferral to be included with each AAC. PGE will address this claim in legal briefs.

Q. Has either Party addressed PGE's concerns regarding the inefficient and redundant process of making multiple filings to recover the same set of expenses through the AAC plus deferral process?

A. No. Neither CUB nor Staff address the inefficient process of double filings. They maintain that the true-up of an AAC must include a deferral.

Q. If the true-up is not considered retroactive ratemaking, can the Parties request an earnings test be applied to all AACs?

A. No. The Parties' argument to support that all AACs may have an earnings test appears to be driven by their claim that it is the deferral portion of an AAC that allows for an earnings test.

Q. How did CUB respond to PGE's reply testimony regarding FERC 580's frequently asked questions on the AAC?

A. CUB argued that PGE's interpretation of the FERC guidelines presented by PGE is incorrect. They claim that the first portion of the FERC quote cited by PGE "does not say that these rates–those subject to an after-the-fact public true-up–are AACs."[31]

Q. How does PGE respond to CUB's argument?

A. CUB's interpretation of this language is incorrect. CUB appears to ignore that the sentence quoted by PGE is the final sentence in the FERC 580's FAQ under the question "What is an Automatic Adjustment Clause." It is unconvincing to assume that this section of FERC's document would include a sentence fragment to describe some other type of process. Furthermore, in 2010, the Edison Electric Institute (EEI) made the same argument as CUB regarding this language, and the FERC did not accept EEI's interpretation.[32]

Q. What recommendation did PGE make regarding the consolidation of deferrals?

A. Given Staff's proposal to consolidate tariffs, PGE is requesting that the Commission agree that it would also be efficient to consolidate like-deferrals into a single filing. PGE attempted this several years ago and Staff's report demanded that PGE file the deferrals in separate dockets.[33]

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[31] CUB/400, Jenks/31 at 5-12.
[32] https://www.federalregister.gov/documents/2010/06/21/2010-14953/commission-information-collection-activities-ferc-form-no-580-request-submitted-for-omb-review-june
[33] Exhibit 3406 at 6-7.

Q. How did Staff respond to PGE's proposal in this UE 416 docket regarding the consolidation of deferrals?

A. They did not respond.

Q. What request did PGE make regarding the MMA deferral?

A. PGE requested that it not be required to file a deferral for its MMAs, which are set during a general rate case and are a base rate charge.

Q. Did Staff respond to PGE's proposal regarding the MMA deferral?

A. No. Staff did not respond.

B. Other Staff Recommendations

Q. What specific recommendations does Staff make regarding AACs other than the request to include an earnings test for all AACs?

A. Staff continues to make the following recommendations other than the request to include an earnings test for all AACs. First, Staff recommends consolidating six different schedules into only two sets of schedules. Second, they recommend adding earnings tests immediately to Schedules 150 and 153. Finally, they also recommend that pilot programs that reach maturity be rolled into base rates. Elsewhere in testimony, they have recommended that the costs associated with two Transportation Electrification (TE) deferral programs be moved to base rates.

Q. What schedules did Staff recommend consolidating?

A. Staff recommended consolidating Schedules 136, 137, 150 and 153 into a single schedule and Schedules 135 and 138 into a single schedule.

Q. Did PGE agree with these recommendations?

A. Yes and no. In our reply testimony, we supported the consolidation of Schedules 135 and 138 because the two schedules have the same allocation methodology, but we did not support the consolidation of Schedules 136, 137, 150 and 153. The allocation methodologies of these schedules do not match, which would result in too much complexity and possibility of error. Instead, we recommended consolidating Schedules 136 and 137 into a single schedule and then consolidating Schedules 150 and 153 into a single schedule.

Q. How did Staff respond to PGE's recommendation regarding their proposal?

A. Staff did not address PGE's recommendation in their rebuttal testimony.

Q. Staff specifically identifies adding an earnings test to Schedules 150. Why does PGE disagree?

A. As provided in reply testimony, an earnings test on Schedule 150 would be entirely inappropriate. Schedule 150 is driven by a legislative mandate to collect ¼ of one percent of revenues from customers to be used for implementing transportation electrification programs. To deny the collection of the ¼ of one percent due to an earnings test would violate the legislative mandate.

Q. Staff disagrees with PGE in its rebuttal testimony regarding Schedule 150 and states that "Schedule 150 concerns both the recovery of costs and matching the costs up to actual spending on TE investments." What does this mean?

A. We do not know what Staff means by this. Whether it is a TE investment or an expense makes no difference here. This is because, unlike an account whereby PGE first knows what will be spent and later trues up actuals, this account is designed such that the information known first is the amount to be collected and then, upon knowing how much will be collected, it is decided how the money will be spent. It would be entirely inappropriate to apply an earnings test to such a structure that is based first on the collection mandated by the legislature. Again, this would violate the legislative mandate because the utility would no longer be collecting the ¼ of one percent. We will reserve our legal arguments for briefs.

Q. Did Staff address this argument regarding the fact that Schedule 150 represents a collection first and spending second?

A. No, Staff did not address this.

Q. Staff also recommends an earnings test on Schedule 153. How does PGE respond to Staff's arguments?

A. PGE is unconvinced by Staff's new arguments in this general rate case. Staff's reversal on this topic is never explained. Figure 2 below shows the most recent Staff report provided on this topic.

Figure 2
Staff Report Date August 23, 2022

Information Related to Future Amortization

- Earnings review – PGE intends to create an AAC to recover the deferred costs. If PGE does so, no earnings review would be required for the prospective rate portion of the AAC. The Commission may use an earnings review on the deferral piece; however, no earnings review is proposed by Staff given the basis of these expenditures.

- Prudence Review – A prudence review will be performed when updating the amounts for amortization as part of the AAC.

For Staff to first provide a written report confirming the importance of these costs and proposing no earnings test – even on the "deferral piece" – and then to request the opposite in this rate case less than a year later when no change in the law or otherwise has occurred since the time of their report is concerning. Again, Staff has not provided an explanation for its shift in perspective regarding the basis of the expenditures, which is to support a Community Benefits and Impacts Advisory Group.

C. Other CUB Recommendations

Q. What specific recommendations that PGE opposes is CUB continuing to make regarding single-issue ratemaking other than the request to include an earnings test for all AACs?

A. In addition to recommending that all AACs have earnings tests, CUB also recommends that:

- There should be a sunset on AACs after three years unless the utility can show why the AAC should not sunset.
- Schedules 110 and 138 should be eliminated.

Q. How does PGE respond to CUB's recommendation that all AACs have a sunset date of no more than three years from their inception and that once the sunset date is reached, PGE must "justify" its continuance in the next general rate case?

A. We will discuss the legal problems with CUB's proposal in briefing, but would highlight here that even though we identified in reply testimony that the law already requires AACs be reviewed at least every two years, CUB dismisses that existing review process. CUB is trying to force a requirement that does not exist in law without any sound justification, supporting analysis or data. Furthermore, the additional application process appears to be inconsistent with the desire expressed by PGE and Staff to lessen the regulatory burden on Staff and stakeholders as well as the filing requirements for utilities.

Q. Please describe CUB's critique of Schedule 110 in rebuttal testimony.

A. CUB's critique of Schedule 110 includes the following:

- It is not difficult to forecast.
- It is not turned over to a government agency.
- It is not very much money.
- It does not meet PGE's description of a cost that should have an AAC.

- It has been in place for more than a decade.

Q. Your reply testimony demonstrated that Schedule 110 costs cannot be included in base rates as proposed by CUB. Can you summarize your reasoning?

A. Schedule 110 is not applicable to all customers. Customers over one MWa for the prior year and customers that qualify as Self-Directing Customers (SDC) are exempt from the charges. If these costs were included in base rates, PGE would not be able to exempt those customers since it does not differentiate base rate schedules by those over one MWa the previous year or SDCs. PGE allocates prices through base rates more broadly. It would be administratively burdensome and set a troubling precedent to allocate these costs outside of the marginal cost studies.

Q. Is there an alternative to including Schedule 110 in base rates?

A. Yes, Schedule 109 recovers energy efficiency costs that are recovered and passed through to the ETO. The allocation methodology and exclusion are the same for Schedules 109 and 110. The costs included in Schedule 110 could be included in Schedule 109 as a part B. Those revenues could be tracked separately from the revenues that flow to the ETO to cover the costs that make up Schedule 110. This would also create consistency with PacifiCorp as they recover both sets of costs through one schedule.

Q. Would this address CUB's concern that Schedule 110 represents a small amount of money?

A. Yes. Schedule 109 currently recovers almost $90 million. Combining Schedule 110 into Schedule 109 would create a slightly larger amount.

Q. What specifically does CUB recommend for Schedule 138?

A. CUB continues to recommend that PGE justify keeping Schedule 138 in its next GRC and specify why it cannot be moved into base rates.

Q. How did PGE respond in reply testimony?

A. As provided in reply testimony, the House Bill (HB) 2193 Energy Storage Cost Recovery Mechanism resulted in multiple projects approved through UM 1856. PGE pursued a RAAC filing for the first of these projects through Dockets UE 370/372, and all participating parties, including CUB, agreed that PGE could recover all UM 1856 storage projects through the AAC mechanism. Once these projects have been completed and/or are no longer pilot projects and the residential pilot is complete, PGE will review the continuing need for Schedule 138.

Q. How did CUB respond to PGE?

A. CUB points to the year HB 2193 passed, 2015, and that it will be at least ten years since then when PGE's next general rate case occurs.

Q. Does that mean that the projects under HB 2193 are almost ten years old?

A. No. It took years for the Commission process to occur and for PGE to develop the projects and pilots. The most recent microgrid project come online this year. Participants continue to enroll in the residential pilot. Passing the legislation was only the start of the process to acquire energy storage.

Q. If PGE has not addressed a particular position of a Party does this constitute agreement with the position?

A. No.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

Exhibit	**Description**
3401	Staff reports on selected PGE AAC deferrals
3402	Staff reports for AAC deferral for PacifiCorp in Docket UM 2224
3403	Legislative Minutes of SB 259, 61st Leg., Reg. Sess. (Or. 1981).
3404	Legislative History of HB 2145, 64th Leg., Reg. Sess. (Or. 1987)
3405	Example analysis regarding percentages
3406	UM 1986 Staff Report

ITEM NO. CA6

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: June 9, 2015

REGULAR ____ **CONSENT** X **EFFECTIVE DATE** **May 7, 2015**

DATE: May 14, 2015

TO: Public Utility Commission

FROM: Judy Johnson JJ

THROUGH: Jason Eisdorfer MH for JE and Marc Hellman

SUBJECT: PORTLAND GENERAL ELECTRIC: (Docket No. UM 1482(5)) Requests reauthorization of deferred accounting for costs associated with Photovoltaic Volumetric Incentive Rate Pilot Program.

STAFF RECOMMENDATION:

I recommend the Commission approve Portland General Electric's (PGE or Company) filing for the 12-month period beginning May 7, 2015, subject to one condition:

- PGE will continue to maintain a balancing account for actual costs based upon the allowable costs identified in OAR 860-084-0280 through 0360, and be able to demonstrate how such costs are incremental to any costs currently included in rates.

DISCUSSION:

PGE makes this filing pursuant to ORS 757.259; OARs 860-027-0300, 860-084-0380, and 860-083-0390; and OPUC Order Nos. 13-250 and 14-271.

PGE requests reauthorization to defer the costs and expenses associated with its Photovoltaic Volumetric Incentive Rate Pilot (PV VIR), also known as the PGE Solar Payment Option (Pilot). This deferral allows PGE to recover costs associated with the Pilot, through Schedule 137, Customer Owned Solar Payment Option Cost Recovery Mechanism.

This accounting facilitates cost recovery authorized by the Commission in Order No. 10-198. PGE intends to recover Pilot costs from all applicable customer classes in the manner authorized by the Commission.

Background
The PV VIR was established in compliance with the rules adopted in Docket AR 538. Commission Order Nos.10-198, 10-304, 11-089, and 11-281 in Docket UM 1452 set out additional requirements. The Pilot provides payments to retail electric customers for electricity generated by permanently installed solar photovoltaic energy systems (i.e. a volumetric incentive rate) through PGE Schedules 215, 216, and 217.

Description of Utility Expense
The expense to be deferred is the prudently incurred incremental costs to administer the program and include volumetric incentive payments and/or retail bill offsets to participants; administrative costs associated with the PV VIR program operations; data collection; development costs for billing and website; customer surveys; and regulatory reporting requirements. Credits to the balancing account include, deposit forfeitures, interconnection application fees, customer charges, assignment fees, and the avoided energy value. Amounts in the balancing account accrue interest at the Commission-authorized rate of return for deferred accounts.

Reason for Deferral
The incremental costs associated with compliance with ORS 757.365 are not currently included in rates. As the statute provides that prudently incurred costs associated with compliance with the statute are recoverable in rates, the deferral is necessary to accomplish that outcome. Continuation of this deferral will minimize the frequency of rate changes or fluctuations and match appropriately the costs borne by and benefits received by customers.

Proposed Accounting
PGE proposes to record the deferred amount as a regulatory asset in FERC Account 182.3, Other Regulatory Assets with a credit to FERC Account 407.4, Regulatory Credits. In the absence of a deferred accounting order from the Commission, PGE would continue to record costs associated with the Pilot to FERC Account 903 Customer Records and Collection Expenses, and FERC Account 908 Customer Assistance expenses.

Estimate of Amounts
PGE estimates incremental costs may range from $6 to $8 million for the 12-month deferral period, largely consisting of VIR payments to participants as more systems are energized. In its 2013 regular session, the legislature enacted House Bill 2893, codified in ORS 757.365(12), adding an additional 2.5 MW capacity to the statewide program. In Docket No. UM 1673, 1.5 MW of that capacity was added to PGE's pilot program. An additional enrollment window was established for customers in 2014. Another enrollment window started May 1, 2015, to account for capacity dropouts from previous

windows. More systems continue to come online and there is additional capacity to enroll customers' systems; therefore, the payment amounts in 2015 and 2016 are expected to increase.

The deferral balance through December 2014 is $1,144,565. The systems currently online now generate less energy in the peak winter months. As more systems begin generating and more energy is produced in summer months from these systems in 2015, the VIR payments will substantially increase.

Information Related to Future Amortization

- Earnings review – Pursuant to ORS 757.259(5), amortization of this deferral does not require an earnings review as it is subject to an automatic adjustment clause under ORS 757.210(1). See also OAR 860-084-0060 and ORS 469A.120.

- Prudence Review – A review to determine that costs were prudently incurred must be done prior to amortization. The review should include the verification of the accounting methodology used to determine the final amortization balance.

- Sharing – This deferral is not subject to a sharing mechanism.

- Rate Spread/Design – In Docket UE 237, the Parties agreed that Schedule 137 costs be allocated to each schedule based on an equal percent of generation revenue applied on a cents per kilowatt-hour basis.

- Three Percent Test (ORS 757.259(6)) – The three percent test measures the annual overall average effect on customer rates resulting from deferral amortizations. The three percent test limits (exceptions at ORS 757.259(7) and (8)) the aggregated deferral amortizations during a 12-month period to no more than three percent of the utility's gross revenues for the preceding year. Because PGE is an electric utility, ORS 757.259(8) allows the Commission to consider up to a six percent limit. The limit for these deferrals will be determined at the time of amortization.

Staff Analysis

As PGE's application to defer is appropriately made under the statutes, and the application meets the requirements of OAR 860-027-0300, Staff recommends approval with the condition included below in the Proposed Commission Motion.

PROPOSED COMMISSION MOTION:
PGE be allowed to track its actual costs related to the Photovoltaic Volumetric Incentive Rate Pilot Program using deferred accounting pursuant to ORS 757.259(2)(e) for the 12-month period beginning May 7, 2015, subject to the following condition:

PGE will continue to maintain a balancing account for actual costs based upon the allowable costs identified in OAR 860-084-0280 through 0360, and be able to demonstrate how such costs are incremental to any costs currently included in rates.

PGE UM 1482(5) PV VIR

ITEM NO. CA8

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: August 8, 2017

REGULAR ____ **CONSENT** __X__ **EFFECTIVE DATE** ____ **May 7, 2017** ____

DATE: August 1, 2017

TO: Public Utility Commission

JC for MM

FROM: Mitchell Moore

J JC for MH

THROUGH: Jason Eisdorfer and Marc Hellman

SUBJECT: PORTLAND GENERAL ELECTRIC: (Docket No. UM 1482(7)) Requests reauthorization to defer costs associated with Solar Payment Option.

STAFF RECOMMENDATION:

Staff recommends the Commission approve Portland General Electric's (PGE or Company) request for reauthorization to defer costs associated with the Solar Payment Option (SPO) for the 12-month period beginning May 7, 2017, subject to the following condition:

- PGE will continue to maintain a balancing account for actual costs based upon the allowable costs identified in OAR 860-084-0280 through 0360, and be able to demonstrate how such costs are incremental to any costs currently included in rates.

DISCUSSION:

Issue

Whether the Commission should reauthorize deferral of costs associated with SPO.

Applicable Law

Pursuant to ORS 757.365(10) all prudently-incurred costs associated with compliance with ORS 757.365 (pilot program for small solar energy systems) are recoverable in the utility's rates. Under ORS 469A.120(1) and (3), all prudently incurred costs associated with the renewable portfolio standards are recovered through an automatic adjustment

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August 1, 2017
Page 2

clause. ORS 757.259 and OAR 860-027-0300 are the laws that concern deferrals and the automatic adjustment mechanism.

The Company makes this filing pursuant to ORS 757.365(10), 469A.120(1) and (3), or 757.259 and OAR 860-027-0300. Deferral of these OSIP costs was granted by the Commission in OPUC Order No. 11-059 and has been annually reauthorized, most recently by Order No. 15-185.

Analysis

PGE requests reauthorization to defer the costs and expenses associated with the photovoltaic feed-in tariff pilot program, including payments to owners of qualified systems for generation (i.e. a volumetric incentive rate) and costs associated with the administration of the pilot program. The Company will seek amortization of the deferred amount in a future Commission proceeding. This deferral is necessary to allow the Company to recover costs associated with compliance with ORS 757.365, as allowed by ORS 757.365(10).

The SPO was established in compliance with the rules adopted in Docket AR 538. Commission Order Nos.10-198, 10-304, 11-089, and 11-281 in Docket UM 1452 set out additional requirements. The Pilot provides payments to retail electric customers for electricity generated by permanently installed solar photovoltaic energy systems (i.e. a volumetric incentive rate) through PGE Schedules 215, 216, and 217.

Description of Utility Expense
The expense to be deferred is the prudently incurred incremental costs to administer the program and include: volumetric incentive payments and/or retail bill offsets to participants; administrative costs associated with the SPO program operations; data collection; development costs for billing and website; customer surveys; and regulatory reporting requirements. Credits to the balancing account include: deposit forfeitures; interconnection application fees; customer charges; assignment fees; and the avoided energy value. Amounts in the balancing account accrue interest at the Commission-authorized rate of return for deferred accounts.

Reason for Deferral
The incremental costs associated with compliance with ORS 757.365 are not currently included in rates. As the statute provides that prudently incurred costs associated with compliance with the statute are recoverable in rates, the deferral is necessary to accomplish that outcome. Continuation of this deferral will minimize the frequency of rate changes or fluctuations and match appropriately the costs borne by and benefits received by customers.

Proposed Accounting
PGE proposes to record the deferred amount as a regulatory asset in FERC Account 182.3, Other Regulatory Assets with a credit to FERC Account 407.4, Regulatory Credits. In the absence of a deferred accounting order from the Commission, PGE would continue to record costs associated with the Pilot to FERC Account 903 Customer Records and Collection Expenses, and FERC Account 908 Customer Assistance expenses.

Estimate of Amounts
PGE estimates incremental costs may range from $6.5 to $7 million for the 12-month deferral period, largely consisting of volumetric incentive rate (VIR) payments to participants as more systems are energized. In its 2013 regular session, the legislature enacted House Bill 2893, codified in ORS 757.365(12), adding an additional 2.5 MW capacity to the statewide program. In Docket No. UM 1673, 1.5 MW of that capacity was added to PGE's pilot program. An additional enrollment window was established for customers in 2014. Another enrollment window started May 1, 2015, to account for capacity dropouts from previous windows. More systems continue to come online and there may be additional capacity to enroll customers' systems; therefore, the payment amounts in 2017 and 2018 are expected to increase.

The deferral balance through December 2016 is approximately $91,000.

Information Related to Future Amortization

- Earnings review – Pursuant to ORS 757.259(5), amortization of this deferral does not require an earnings review as it is subject to an automatic adjustment clause under ORS 757.210(1). See also OAR 860-084-0060 and ORS 469A.120.

- Prudence Review – A review to determine that costs were prudently incurred must be done prior to amortization. The review should include the verification of the accounting methodology used to determine the final amortization balance.

- Sharing – This deferral is not subject to a sharing mechanism.

- Rate Spread/Design – In Docket UE 237, the Parties agreed that Schedule 137 costs be allocated to each schedule based on an equal percent of generation revenue applied on a cents per kilowatt-hour basis.

- Three Percent Test (ORS 757.259(6)) – The three percent test measures the annual overall average effect on customer rates resulting from deferral amortizations. The three percent test limits (exceptions at ORS 757.259(7) and (8)) the aggregated deferral amortizations during a 12-month period to no more than three percent of the utility's gross revenues for the preceding year. Because PGE is an electric utility, ORS 757.259(8) allows the Commission to consider up to a six percent limit. The limit for these deferrals will be determined at the time of amortization.

<u>Conclusion</u>

As PGE's application to defer is appropriately made under the statutes, and the application meets the requirements of OAR 860-027-0300, Staff recommends approval with the condition included below in the Proposed Commission Motion.

PROPOSED COMMISSION MOTION:

PGE be allowed to track its actual costs related to the Photovoltaic Volumetric Incentive Rate Pilot Program using deferred accounting pursuant to ORS 757.259(2)(e) for the 12-month period beginning May 7, 2017, subject to the following condition:

PGE will continue to maintain a balancing account for actual costs based upon the allowable costs identified in OAR 860-084-0280 through 0360, and be able to demonstrate how such costs are incremental to any costs currently included in rates.

ITEM NO. CA7

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: July 3, 2018

REGULAR ____ **CONSENT** X **EFFECTIVE DATE** **May 7, 2018**

DATE: June 25, 2018

TO: Public Utility Commission

FROM: Mitchell Moore MAM

THROUGH: Jason Eisdorfer and John Crider J JC

SUBJECT: PORTLAND GENERAL ELECTRIC: (Docket No. UM 1482(8)) Requests reauthorization to defer costs associated with the Photovoltaic Volumetric Incentive Rate Pilot.

STAFF RECOMMENDATION:

Staff recommends the Commission approve Portland General Electric's (PGE or Company) request for reauthorization to defer costs associated with the Photovoltaic Volumetric Incentive Rate Pilot (PV VIR) for the 12-month period beginning May 7, 2018, subject to the following condition:

- PGE will continue to maintain a balancing account for actual costs based upon the allowable costs identified in OAR 860-084-0280 through 0360, and be able to demonstrate how such costs are incremental to any costs currently included in rates.

DISCUSSION:

Issue

Whether the Commission should reauthorize deferral of costs associated with its PV VIR pilot.

Applicable Law

Pursuant to ORS 757.365(10) all prudently-incurred costs associated with compliance with ORS 757.365 (pilot program for small solar energy systems) are recoverable in the utility's rates. Under ORS 469A.120(1) and (3), all prudently incurred costs associated

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with the renewable portfolio standards are recovered through an automatic adjustment clause. ORS 757.259 and OAR 860-027-0300 are the laws that concern deferrals and the automatic adjustment mechanism.

The Company makes this filing pursuant to ORS 757.365(10), 469A.120(1) and (3), or 757.259 and OAR 860-027-0300. Deferral of these OSIP costs was granted by the Commission in OPUC Order No. 11-059 and has been annually reauthorized, most recently by Order No. 17-304.

Analysis

PGE requests reauthorization to defer the costs and expenses associated with the photovoltaic feed-in tariff pilot program, including payments to owners of qualified systems for generation (i.e. a volumetric incentive rate) and costs associated with the administration of the pilot program. The Company will seek amortization of the deferred amount in a future Commission proceeding. This deferral is necessary to allow the Company to recover costs associated with compliance with ORS 757.365, as allowed by ORS 757.365(10).

The PV VIR was established in compliance with the rules adopted in Docket AR 538. Commission Order Nos.10-198, 10-304, 11-089, and 11-281 in Docket UM 1452 set out additional requirements. The Pilot provides payments to retail electric customers for electricity generated by permanently installed solar photovoltaic energy systems (i.e. a volumetric incentive rate) through PGE Schedules 215, 216, and 217.

Description of Utility Expense:
The expense to be deferred is the prudently incurred incremental costs to administer the program and include: volumetric incentive payments and/or retail bill offsets to participants; administrative costs associated with the PV VIR program operations; data collection; development costs for billing and website; customer surveys; and regulatory reporting requirements. Credits to the balancing account include: deposit forfeitures; interconnection application fees; customer charges; assignment fees; and the avoided energy value. Amounts in the balancing account accrue interest at the Commission-authorized rate of return for deferred accounts.

Reason for Deferral:
The incremental costs associated with compliance with ORS 757.365 are not currently included in rates. As the statute provides that prudently incurred costs associated with compliance with the statute are recoverable in rates, the deferral is necessary to accomplish that outcome. Continuation of this deferral will minimize the frequency of

rate changes or fluctuations and match appropriately the costs borne by and benefits received by customers.

Proposed Accounting:
PGE proposes to record the deferred amount as a regulatory asset in FERC Account 182.3, Other Regulatory Assets with a credit to FERC Account 407.4, Regulatory Credits. In the absence of a deferred accounting order from the Commission, PGE would continue to record costs associated with the Pilot to FERC Account 903 Customer Records and Collection Expenses, and FERC Account 908 Customer Assistance expenses.

Estimate of Amounts:
PGE estimates incremental costs may range from $6.5 to $7 million for the 12-month deferral period, largely consisting of volumetric incentive rate (VIR) payments to participants as more systems are energized.

The deferral balance as of the date of filing is approximately $(57,215).

Information Related to Future Amortization:

- Earnings review – Pursuant to ORS 757.259(5), amortization of this deferral does not require an earnings review as it is subject to an automatic adjustment clause under ORS 757.210(1). See also OAR 860-084-0060 and ORS 469A.120.

- Prudence Review – A review to determine that costs were prudently incurred must be done prior to amortization. The review should include the verification of the accounting methodology used to determine the final amortization balance.

- Sharing – This deferral is not subject to a sharing mechanism.

- Rate Spread/Design – In Docket UE 237, the Parties agreed that Schedule 137 costs be allocated to each schedule based on an equal percent of generation revenue applied on a cents per kilowatt-hour basis.

- Three Percent Test (ORS 757.259(6)) – The three percent test measures the annual overall average effect on customer rates resulting from deferral amortizations. The three percent test limits (exceptions at ORS 757.259(7) and (8)) the aggregated deferral amortizations during a 12-month period to no more than three percent of the utility's gross revenues for the preceding year. Because PGE is an electric utility, ORS 757.259(8) allows the Commission to consider up to a six percent limit. The limit for these deferrals will be determined at the time of amortization.

Conclusion

As PGE's application to defer is appropriately made under the statutes, and the application meets the requirements of OAR 860-027-0300, Staff recommends approval with the condition included below in the Proposed Commission Motion.

PROPOSED COMMISSION MOTION:

PGE be allowed to track its actual costs related to the Photovoltaic Volumetric Incentive Rate Pilot Program using deferred accounting pursuant to ORS 757.259(2)(e) for the 12-month period beginning May 7, 2018, subject to the following condition:

PGE will continue to maintain a balancing account for actual costs based upon the allowable costs identified in OAR 860-084-0280 through 0360, and be able to demonstrate how such costs are incremental to any costs currently included in rates.

PGE UM 1482(8) PV VIR

ITEM NO. CA7

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: August 27, 2019

REGULAR ____ CONSENT _X_ EFFECTIVE DATE ______May 7, 2019______

DATE: August 19, 2019

TO: Public Utility Commission

FROM: Mitchell Moore

THROUGH: Jason Eisdorfer and John Crider **SIGNED**

SUBJECT: PORTLAND GENERAL ELECTRIC: (Docket No. UM 1482(9)) Requests reauthorization to defer costs associated with the Photovoltaic Volumetric Incentive Rate Pilot.

STAFF RECOMMENDATION:

Staff recommends the Commission approve Portland General Electric's (PGE or Company) request for reauthorization to defer costs associated with the Photovoltaic Volumetric Incentive Rate Pilot (PV VIR) for the 12-month period beginning May 7, 2019, subject to the following condition:

- PGE will continue to maintain a balancing account for actual costs based upon the allowable costs identified in OAR 860-084-0280 through 0360, and be able to demonstrate how such costs are incremental to any costs currently included in rates.

DISCUSSION:

Issue

Whether the Commission should reauthorize deferral of costs associated with its PV VIR pilot.

Applicable Law

Pursuant to ORS 757.365(10) all prudently-incurred costs associated with compliance with ORS 757.365 (pilot program for small solar energy systems) are recoverable in the utility's rates. Under ORS 469A.120(1) and (3), all prudently incurred costs associated with the renewable portfolio standards are recovered through an automatic adjustment clause. ORS 757.259 and OAR 860-027-0300 are the laws that concern deferrals and the automatic adjustment mechanism.

The Company makes this filing pursuant to ORS 757.365(10), 469A.120(1) and (3), or 757.259 and OAR 860-027-0300. Deferral of these OSIP costs was granted by the Commission in OPUC Order No. 11-059 and has been annually reauthorized, most recently by Order No. 18-259.

Analysis

PGE requests reauthorization to defer the costs and expenses associated with the photovoltaic feed-in tariff pilot program, including payments to owners of qualified systems for generation (i.e. a volumetric incentive rate) and costs associated with the administration of the pilot program. The Company will seek amortization of the deferred amount in a future Commission proceeding. This deferral is necessary to allow the Company to recover costs associated with compliance with ORS 757.365, as allowed by ORS 757.365(10).

The PV VIR was established in compliance with the rules adopted in Docket AR 538. Commission Order Nos.10-198, 10-304, 11-089, and 11-281 in Docket UM 1452 set out additional requirements. The Pilot provides payments to retail electric customers for electricity generated by permanently installed solar photovoltaic energy systems (i.e. a volumetric incentive rate) through PGE Schedules 215, 216, and 217.

Description of Utility Expense
The expense to be deferred is the prudently incurred incremental costs to administer the program and include: volumetric incentive payments and/or retail bill offsets to participants; administrative costs associated with the PV VIR program operations; data collection; development costs for billing and website; customer surveys; and regulatory reporting requirements. Credits to the balancing account include: deposit forfeitures; interconnection application fees; customer charges; assignment fees; and the avoided energy value. Amounts in the balancing account accrue interest at the Commission-authorized rate of return for deferred accounts.

Reason for Deferral
The incremental costs associated with compliance with ORS 757.365 are not currently included in rates. As the statute provides that prudently incurred costs associated with compliance with the statute are recoverable in rates, the deferral is necessary to accomplish that outcome. Continuation of this deferral will minimize the frequency of

rate changes or fluctuations and match appropriately the costs borne by and benefits received by customers.

Proposed Accounting
PGE proposes to record the deferred amount as a regulatory asset in FERC Account 182.3, Other Regulatory Assets with a credit to FERC Account 407.4, Regulatory Credits. In the absence of a deferred accounting order from the Commission, PGE would continue to record costs associated with the Pilot to FERC Account 903 Customer Records and Collection Expenses, and FERC Account 908 Customer Assistance expenses.

Estimate of Amounts
PGE estimates incremental costs may range from $7 to $8 million for the 12-month deferral period, largely consisting of volumetric incentive rate (VIR) payments to participants as more systems are energized.

The deferral balance as of the date of filing is approximately $(759,608).

Information Related to Future Amortization

- Earnings review – Pursuant to ORS 757.259(5), amortization of this deferral does not require an earnings review as it is subject to an automatic adjustment clause under ORS 757.210(1). See also OAR 860-084-0060 and ORS 469A.120.

- Prudence Review – A review to determine that costs were prudently incurred must be done prior to amortization. The review should include the verification of the accounting methodology used to determine the final amortization balance.

- Sharing – This deferral is not subject to a sharing mechanism.

- Rate Spread/Design – In Docket UE 237, the Parties agreed that Schedule 137 costs be allocated to each schedule based on an equal percent of generation revenue applied on a cents per kilowatt-hour basis.

- Three Percent Test (ORS 757.259(6)) – The three percent test measures the annual overall average effect on customer rates resulting from deferral amortizations. The three percent test limits (exceptions at ORS 757.259(7) and (8)) the aggregated deferral amortizations during a 12-month period to no more than three percent of the utility's gross revenues for the preceding year. Because PGE is an electric utility, ORS 757.259(8) allows the Commission to consider up to a six percent limit. The limit for these deferrals will be determined at the time of amortization.

Conclusion

As PGE's application to defer is appropriately made under the statutes, and the application meets the requirements of OAR 860-027-0300, Staff recommends approval with the condition included below in the Proposed Commission Motion.

PROPOSED COMMISSION MOTION:

PGE be allowed to track its actual costs related to the Photovoltaic Volumetric Incentive Rate Pilot Program using deferred accounting pursuant to ORS 757.259(2)(e) for the 12-month period beginning May 7, 2019, subject to the following condition:

PGE will continue to maintain a balancing account for actual costs based upon the allowable costs identified in OAR 860-084-0280 through 0360, and be able to demonstrate how such costs are incremental to any costs currently included in rates.

PGE UM 1482(9) PV VIR

ITEM NO. CA4

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: June 16, 2020

REGULAR ____ CONSENT _X_ EFFECTIVE DATE ______May 7, 2020______

DATE: June 8, 2020

TO: Public Utility Commission

FROM: Mitchell Moore

THROUGH: Bryan Conway, Michael Dougherty, John Crider, and Matt Muldoon **SIGNED**

SUBJECT: PORTLAND GENERAL ELECTRIC:
(Docket No. UM 1482(10))
Requests reauthorization to defer costs associated with the Photovoltaic Volumetric Incentive Rate Pilot.

STAFF RECOMMENDATION:

Staff recommends the Public Utility Commission of Oregon (Commission) approve Portland General Electric's (PGE or Company) request for reauthorization to defer costs associated with the Photovoltaic Volumetric Incentive Rate Pilot (PV VIR) for the 12-month period beginning May 7, 2020, subject to the following condition:

- PGE will continue to maintain a balancing account for actual costs based upon the allowable costs identified in OAR 860-084-0280 through 0360, and be able to demonstrate how such costs are incremental to any costs currently included in rates.

DISCUSSION:

Issue

Whether the Commission should reauthorize deferral of costs associated with its PV VIR pilot.

Applicable Law

Pursuant to ORS 757.365(10) all prudently-incurred costs associated with compliance with ORS 757.365 (pilot program for small solar energy systems) are recoverable in the utility's rates. Under ORS 469A.120(1) and (3), all prudently incurred costs associated with the renewable portfolio standards are recovered through an automatic adjustment clause. ORS 757.259 and OAR 860-027-0300 are the laws that concern deferrals and the automatic adjustment mechanism.

The Company makes this filing pursuant to ORS 757.365(10), 469A.120(1) and (3), or 757.259 and OAR 860-027-0300. Deferral of these OSIP costs was granted by the Commission in OPUC Order No. 11-059 and has been annually reauthorized, most recently by Order No. 19-283.

Analysis

PGE requests reauthorization to defer the costs and expenses associated with the photovoltaic feed-in tariff pilot program, including payments to owners of qualified systems for generation (i.e. a volumetric incentive rate) and costs associated with the administration of the pilot program. The Company will seek amortization of the deferred amount in a future Commission proceeding. This deferral is necessary to allow the Company to recover costs associated with compliance with ORS 757.365, as allowed by ORS 757.365(10).

The PV VIR was established in compliance with the rules adopted in Docket No. AR 538. Commission Order Nos.10-198, 10-304, 11-089, and 11-281 in Docket No. UM 1452 set out additional requirements. The Pilot provides payments to retail electric customers for electricity generated by permanently installed solar photovoltaic energy systems (i.e. a volumetric incentive rate) through PGE Schedules 215, 216, and 217.

Description of Utility Expense:
The expense to be deferred is the prudently incurred incremental costs to administer the program and include: volumetric incentive payments and/or retail bill offsets to participants; administrative costs associated with the PV VIR program operations; data collection; development costs for billing and website; customer surveys; and regulatory reporting requirements. Credits to the balancing account include: deposit forfeitures; interconnection application fees; customer charges; assignment fees; and the avoided energy value. Amounts in the balancing account accrue interest at the Commission-authorized rate of return for deferred accounts.

Reason for Deferral:
The incremental costs associated with compliance with ORS 757.365 are not currently included in rates. As the statute provides that prudently incurred costs associated with compliance with the statute are recoverable in rates, the deferral is necessary to

accomplish that outcome. Continuation of this deferral will minimize the frequency of rate changes or fluctuations and match appropriately the costs borne by and benefits received by customers.

Proposed Accounting:
PGE proposes to record the deferred amount as a regulatory asset in FERC Account 182.3, Other Regulatory Assets with a credit to FERC Account 407.4, Regulatory Credits. In the absence of a deferred accounting order from the Commission, PGE would continue to record costs associated with the Pilot to FERC Account 903 Customer Records and Collection Expenses, and FERC Account 908 Customer Assistance expenses.

Estimate of Amounts:
PGE estimates incremental costs may range from $7 to $8 million for the 12-month deferral period, largely consisting of volumetric incentive rate (VIR) payments to participants as more systems are energized.

Information Related to Future Amortization:

- Earnings review – Pursuant to ORS 757.259(5), amortization of this deferral does not require an earnings review as it is subject to an automatic adjustment clause under ORS 757.210(1). See also OAR 860-084-0060 and ORS 469A.120.

- Prudence Review – A review to determine that costs were prudently incurred must be done prior to amortization. The review should include the verification of the accounting methodology used to determine the final amortization balance.

- Sharing – This deferral is not subject to a sharing mechanism.

- Rate Spread/Design – In Docket No. UE 237, the Parties agreed that Schedule 137 costs be allocated to each schedule based on an equal percent of generation revenue applied on a cents per kilowatt-hour basis.

- Three Percent Test (ORS 757.259(6)) – The three percent test measures the annual overall average effect on customer rates resulting from deferral amortizations. The three percent test limits (exceptions at ORS 757.259(7) and (8)) the aggregated deferral amortizations during a 12-month period to no more than three percent of the utility's gross revenues for the preceding year. Because PGE is an electric utility, ORS 757.259(8) allows the Commission to consider up to a six percent limit. The limit for these deferrals will be determined at the time of amortization.

Conclusion

As PGE's application to defer is appropriately made under the statutes, and the application meets the requirements of OAR 860-027-0300, Staff recommends approval with the condition included below in the Proposed Commission Motion.

PROPOSED COMMISSION MOTION:

Allow PGE to track its actual costs related to the Photovoltaic Volumetric Incentive Rate Pilot Program using deferred accounting pursuant to ORS 757.259(2)(e) for the 12-month period beginning May 7, 2020, subject to the following condition:

- PGE will continue to maintain a balancing account for actual costs based upon the allowable costs identified in OAR 860-084-0280 through 0360, and be able to demonstrate how such costs are incremental to any costs currently included in rates.

PGE UM 1482(10) PV VIR

ITEM NO. CA1

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: June 15, 2021

REGULAR ____ **CONSENT** __X__ **EFFECTIVE DATE** ______**May 7, 2021**______

DATE: June 8, 2021

TO: Public Utility Commission

FROM: Mitchell Moore

THROUGH: Bryan Conway, John Crider, and Matt Muldoon **SIGNED**

SUBJECT: PORTLAND GENERAL ELECTRIC:
(Docket No. UM 1482(11))
Requests reauthorization to defer costs associated with the Photovoltaic Volumetric Incentive Rate Pilot.

STAFF RECOMMENDATION:

Staff recommends the Commission approve Portland General Electric's (PGE or Company) request for reauthorization to defer costs associated with the Photovoltaic Volumetric Incentive Rate Pilot (PV VIR) for the 12-month period beginning May 7, 2021, subject to the following condition:

- PGE will continue to maintain a balancing account for actual costs based upon the allowable costs identified in OAR 860-084-0280 through 0360, and be able to demonstrate how such costs are incremental to any costs currently included in rates.

DISCUSSION:

Issue

Whether the Commission should reauthorize deferral of costs associated with its PV VIR pilot.

Applicable Law

Pursuant to ORS 757.365(10), all prudently-incurred costs associated with compliance with ORS 757.365 (pilot program for small solar energy systems) are recoverable in the utility's rates. Under ORS 469A.120(1) and (3), all prudently incurred costs associated with the renewable portfolio standards are recovered through an automatic adjustment clause. ORS 757.259 and OAR 860-027-0300 are the laws that concern deferrals and the automatic adjustment mechanism.

The Company makes this filing pursuant to ORS 757.365(10), 469A.120(1) and (3), ORS 757.259, and OAR 860-027-0300. Deferral of these OSIP costs was granted by the Commission in OPUC Order No. 11-059 and has been annually reauthorized, most recently by Order No. 20-195.

Analysis

PGE requests reauthorization to defer the costs and expenses associated with the photovoltaic feed-in tariff pilot program, including payments to owners of qualified systems for generation (i.e. a volumetric incentive rate) and costs associated with the administration of the pilot program. The Company will seek amortization of the deferred amount in a future Commission proceeding. This deferral is necessary to allow the Company to recover costs associated with compliance with ORS 757.365, as allowed by ORS 757.365(10).

The PV VIR was established in compliance with the rules adopted in Docket No. AR 538. Commission Order Nos.10-198, 10-304, 11-089, and 11-281 in Docket No. UM 1452 set out additional requirements. The Pilot provides payments to retail electric customers for electricity generated by permanently installed solar photovoltaic energy systems (i.e. a volumetric incentive rate) through PGE Schedules 215, 216, and 217.

Description of Utility Expense
The expense to be deferred is the prudently incurred incremental costs to administer the program and include: volumetric incentive payments and/or retail bill offsets to participants; administrative costs associated with the PV VIR program operations; data collection; development costs for billing and website; customer surveys; and regulatory reporting requirements. Credits to the balancing account include: deposit forfeitures; interconnection application fees; customer charges; assignment fees; and the avoided energy value. Amounts in the balancing account accrue interest at the Commission-authorized rate of return for deferred accounts.

Reason for Deferral
The incremental costs associated with compliance with ORS 757.365 are not currently included in rates. As the statute provides that prudently incurred costs associated with compliance with the statute are recoverable in rates, the deferral is necessary to

accomplish that outcome. Continuation of this deferral will minimize the frequency of rate changes or fluctuations and match appropriately the costs borne by and benefits received by customers.

Proposed Accounting
PGE proposes to record the deferred amount as a regulatory asset in FERC Account 182.3, Other Regulatory Assets with a credit to FERC Account 407.4, Regulatory Credits. In the absence of a deferred accounting order from the Commission, PGE would continue to record costs associated with the Pilot to FERC Account 903 Customer Records and Collection Expenses, and FERC Account 908 Customer Assistance expenses.

Estimate of Amounts
PGE estimates incremental costs may range from $7 to $8 million for the 12-month deferral period, largely consisting of volumetric incentive rate (VIR) payments to participants as more systems are energized.

Information Related to Future Amortization

- Earnings review – Pursuant to ORS 757.259(5), amortization of this deferral does not require an earnings review as it is subject to an automatic adjustment clause under ORS 757.210(1). See also OAR 860-084-0060 and ORS 469A.120.

- Prudence Review – A review to determine that costs were prudently incurred must be done prior to amortization. The review should include the verification of the accounting methodology used to determine the final amortization balance.

- Sharing – This deferral is not subject to a sharing mechanism.

- Rate Spread/Design – In Docket No. UE 237, the Parties agreed that Schedule 137 costs be allocated to each schedule based on an equal percent of generation revenue applied on a cents per kilowatt-hour basis.

- Three Percent Test (ORS 757.259(6)) – The three percent test measures the annual overall average effect on customer rates resulting from deferral amortizations. The three percent test limits (exceptions at ORS 757.259(7) and (8)) the aggregated deferral amortizations during a 12-month period to no more than three percent of the utility's gross revenues for the preceding year. Because PGE is an electric utility, ORS 757.259(8) allows the Commission to consider up to a six percent limit. The limit for these deferrals will be determined at the time of amortization.

Conclusion

As PGE's application to defer is appropriately made under the statutes, and the application meets the requirements of OAR 860-027-0300, Staff recommends approval with the condition included below in the Proposed Commission Motion.

PROPOSED COMMISSION MOTION:

Approve Portland General Electric's request for reauthorization to defer costs associated with the Photovoltaic Volumetric Incentive Rate Pilot for the 12-month period beginning May 7, 2021, subject to the following condition:

- PGE will continue to maintain a balancing account for actual costs based upon the allowable costs identified in OAR 860-084-0280 through 0360, and be able to demonstrate how such costs are incremental to any costs currently included in rates.

ITEM NO. CA5

PUBLIC UTILITY COMMISSION OF OREGON
CONFIDENTIAL STAFF REPORT
PUBLIC MEETING DATE: November 15, 2022

REGULAR ____ **CONSENT** __X__ **EFFECTIVE DATE** __________N/A__________

DATE: November 3, 2022

TO: Public Utility Commission

FROM: Kathy Zarate

THROUGH: Bryan Conway, Marc Hellman, and Matt Muldoon **SIGNED**

SUBJECT: PORTLAND GENERAL ELECTRIC:
(Docket No. UM 1482(12))
Requests reauthorization to defer costs associated with the Photovoltaic Volumetric Incentive Rate Pilot.

STAFF RECOMMENDATION:

Staff recommends the Commission approve Portland General Electric's (PGE or Company) request for reauthorization to defer costs associated with the Photovoltaic Volumetric Incentive Rate Pilot (PV VIR) for the 12-month period beginning May 27, 2022, through May 26, 2023, subject to the following Staff recommended condition: PGE will continue to maintain a balancing account for actual costs based upon the allowable costs identified in OAR 860-084-0280 through 0360; and, be required to demonstrate how such costs are incremental to any costs currently included in rates.

DISCUSSION:

Issue

Whether the Commission should approve PGE's request reauthorize deferral of costs associated with its PV VIR pilot.

Applicable Law

Pursuant to ORS 757.365(10), all prudently-incurred costs associated with compliance with ORS 757.365 (pilot program for small solar energy systems) are recoverable in the utility's rates.

Under ORS 469A.120(1) and (3), all prudently incurred costs associated with the renewable portfolio standards are recovered through an automatic adjustment clause. ORS 757.259 and OAR 860-027-0300 are the laws that concern deferrals and the automatic adjustment mechanism.

The Company made this filing pursuant to ORS 757.365(10), 469A.120(1) and (3), ORS 757.259, and OAR 860-027-0300. Deferral of these OSIP costs was granted by the Commission in OPUC Order No. 11-059 and has been annually reauthorized—most recently by Order No. 21-196.

Analysis

Background
PGE requests reauthorization to defer the costs and expenses associated with the photovoltaic feed-in tariff pilot program, including payments to owners of qualified systems for generation (i.e., a volumetric incentive rate) and costs associated with the administration of the pilot program.

The Company will seek amortization of the deferred amount in a future Commission proceeding. This deferral is necessary to allow the Company to recover costs associated with compliance with ORS 757.365, as allowed by ORS 757.365(10).

The PV VIR was established in compliance with the rules adopted in Docket No. AR 538. Commission Order Nos.10-198, 10-304, 11-089, and 11-281 in Docket No. UM 1452 set out additional requirements. The Pilot provides payments to retail electric customers for electricity generated by permanently installed solar photovoltaic energy systems (i.e., a volumetric incentive rate) through PGE Schedules 215, 216, and 217.

This deferral, also, allows PGE to recover costs associated with the pilot, through an AAC under PGE Schedule 137, Customer Owned Solar Payment Option Cost Recovery Mechanism.

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Description of Expenses
The expense to be deferred is the prudently incurred incremental costs to administer the program and include volumetric incentive payments and/or retail bill offsets to participants; administrative costs associated with the PV VIR program operations; data collection; development costs for billing and website; customer surveys; and regulatory reporting requirements. Credits to the balancing account include deposit forfeitures; interconnection application fees; customer charges; assignment fees; and the avoided energy value. Amounts in the balancing account accrue interest at the Commission authorized rate of return for deferred accounts.

Reason for Deferral
The incremental costs associated with compliance with ORS 757.365 are not currently included in rates. As the statute provides that prudently incurred costs associated with compliance with the statute are recoverable in rates, the deferral is necessary to accomplish that outcome. Continuation of this deferral will minimize the frequency of rate changes or fluctuations and match appropriately the costs borne by and benefits received by customers

Proposed Accounting
PGE proposes to record the deferred amount as a regulatory asset in FERC Account 182.3, Other Regulatory Assets with a credit to FERC Account 407.4, Regulatory Credits. In the absence of a deferred accounting order from the Commission, PGE would continue to record costs associated with the Pilot to FERC Account 903, Customer Records and Collection Expenses, and FERC Account 908. Customer Assistance expenses.

Estimated Deferrals in Authorization for the Next 12 Months
The amounts to be deferred consist of incremental costs of the Pilot for one, VIR payments to participants including any retail electricity service bill offset amounts, and two, program costs incurred to implement and administer the requirements for the Pilot.

For both cost categories, the amounts deferred depend upon actual participation levels and PV system sizes of participants in the Pilot. PGE estimates incremental costs may range from $7 million to $8 million for the deferral period, May 27, 2022, through May 26, 2023, consisting largely of VIR payments to participants.

Information Related to Future Amortization
- Earnings review – PGE Schedule 137 recovers costs associated with the Solar Payment Option Pilot not otherwise included in rates. Because this schedule is an AAC as provided under ORS 469A.120 and defined in the

Renewable Portfolio Standards, ORS 757.210, an earnings review is not applicable to this deferral. See also PGE Schedules 215, 216, and 217.

- Prudence Review – A review to determine that costs were prudently incurred must be done prior to amortization. The review should include the verification of the accounting methodology used to determine the final amortization balance. In addition, any amounts includable in the deferral should be shown that such costs are not being recovered in current rates, meaning they are incremental costs above those collected in rates.

- Sharing – This deferral is not subject to a sharing mechanism.

- Rate Spread/Design – In Docket No. UE 237, the Parties agreed that Schedule 137 costs be allocated to each schedule based on an equal percent of generation revenue applied on a cents per kilowatt-hour basis.

- Three Percent Test (ORS 757.259(6)) – The three percent test measures the annual overall average effect on customer rates resulting from deferral amortizations. The three percent test limits (exceptions at ORS 757.259(7) and (8)) the aggregated deferral amortizations during a 12-month period to no more than three percent of the utility's gross revenues for the preceding year. Because PGE is an electric utility, ORS 757.259(8) allows the Commission to consider up to a six percent limit. The limit for these deferrals will be determined at the time of amortization.

Conclusion

As PGE's application to defer is appropriately made under the statutes, and the application meets the requirements of OAR 860-027-0300, Staff recommends approval with the condition included below in the Proposed Commission Motion.

PGE has reviewed this memo and agrees with its content.

PROPOSED COMMISSION MOTION:

Approve Portland General Electric's request for reauthorization to defer costs associated with the Photovoltaic Volumetric Incentive Rate Pilot for the 12-month period beginning May 27, 2022, through May 26, 2023, subject to Staff's recommended condition.

ITEM NO. CA7

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: January 28, 2015

REGULAR ____ CONSENT X EFFECTIVE DATE January 1, 2015

DATE: January 7, 2015

TO: Public Utility Commission

FROM: Judy Johnson JJ

THROUGH: Jason Eisdorfer and Marc Hellman

SUBJECT: PORTLAND GENERAL ELECTRIC: (Docket No. UM 1514(4)) Requests reauthorization to defer the incremental costs associated with Automated Demand Response.

STAFF RECOMMENDATION:

I recommend that Portland General Electric's application be approved for the 12-month period beginning January 1, 2015.

DISCUSSION:

Portland General Electric (PGE or Company) makes this filing pursuant to ORS 757.259 and OAR 860-027-0300, to request reauthorization to defer the incremental costs associated with its Automated Demand Response Program (ADR) for the 12-month period beginning January 1, 2015.

The deferral of incremental ADR costs, as an automatic adjustment clause, and the associated cost recovery tariff (Advice 10-29, Schedule 135) were initially authorized by Commission Order No. 11-82, as part of a two-year pilot program.

Background

PGE filed an application for deferral of incremental costs associated with ADR on December 29, 2010, seeking deferral from January 1, 2011, through December 31, 2011. This deferral and cost recovery tariff (Advice 10-29, Schedule 135) was approved in a Commission Order No. 11-182 on June 1, 2011. Subsequently, the Company filed for reauthorization for the deferral on December 23, 2011, for the period January 1, 2012, through December 13, 2012, January 1, 2013, through December 31, 2013, and January 1, 2014, through

December 31, 2014.

PGE seeks reauthorization for a deferral of incremental costs associated with the ADR Program and the new Pilot timeline for the period January 1, 2015, through December 31, 2015.

First ADR Pilot Period
PGE selected a third-party provider based on a combination of good credit, bidding summer and winter events, better technology, and a stronger marketing plan. The provider began its program marketing on September 1, 2011, but failed to meet the initial capacity milestone of 5 MW for the first winter season. The provider then began to experience financial difficulties and failed to meet additional terms of its agreement for the ADR pilot. On April 30, 2012, PGE terminated its contract with the provider.

New Proposed ADR Pilot Period
Although the first program was terminated, PGE believed that ADR pilot could still be a valuable and viable resource. Consequently, PGE selected a new provider and implemented a new pilot. PGE proposed that the new ADR pilot period run through June 2015. This will allow four operating seasons (two full years) to be evaluated for performance and cost effectiveness with the evaluation to be completed by April 2015. If the evaluation is favorable, the second period will run through 2016, which will allow a second evaluation to review the entire pilot with the evaluation to be completed by April 2016. If the second evaluation is favorable, PGE will submit the ADR as an on-going capacity resource in its Annual Power Cost Update (Schedule 125) and Power Cost Adjustment Mechanism (Schedule 126) similar to other power cost and capacity items.

Description of Amounts
Pursuant to ORS 757.259(2)(e), PGE seeks renewal of deferred accounting treatment for the incremental costs associated with an ADR. The approval of the Application will also enable the continued use of an automatic adjustment clause rate schedule which will provide for recovery of the incremental costs associated with the ADR through tariff Schedule 135.

Reasons for Deferral
Pursuant to ORS 757.259(2)(e), PGE seeks to continue a deferred accounting treatment for the incremental costs associated with the ADR (initially authorized by the Commission through Order No. 11-082 on June 1, 2011). The granting of this reauthorization application will minimize the frequency of rate changes and match appropriately the costs borne by, and benefits received by, customers.

Without reauthorization, the current authorization to defer costs will expire on December 31, 2014. PGE is filing this reauthorization application for the period commencing January 1, 2015 through December 31, 2015.

Proposed Accounting

PGE proposes to record the deferred costs in FERG account 182.3 (Regulatory Assets), with the offsetting credit recorded to FERG account 131 (Cash).

Estimate of Amounts

PGE estimates the amounts to be deferred in 2015 to be approximately $1.76 million.

Information Related to Future Amortization

- Earnings review -An earnings review does not apply to an automatic adjustment clause, pursuant to ORS 757.259(5).

- Prudence Review -A prudence review should include a verification that deferred amounts are incremental, and verification of the accounting methodology used to determine the final amortization balance.

- Sharing –If the ADR is deemed successful, then the proposal is for subsequent costs to flow through PGE's Annual Power Cost Update (Schedule 125) and Power Cost Adjustment Mechanism (PCAM) (Schedule 126). The PCAM is subject to the dead bands and sharing percent's as specified by Commission Order Nos. 07-015 and 10-478.

- Rate Spread/Design –Per Commission Order No. 11-517, tariff Schedule 135 will allocate the costs of the ADR on the basis of an equal percent of forecast generation revenues.

- Three Percent Test (ORS 757.259(6)) - The three percent test measures the annual overall average effect on customer rates resulting from deferral amortizations. The three percent test limits (exceptions at ORS 757.259(7) and (8)) the aggregated deferral amortizations during a 12-month period to no more than three percent of the utility's gross revenues for the preceding year. Because PGE is an electric utility, ORS 757.259(8) allows the Commission to consider up to a six percent limit.

Staff Analysis

The rationale for this deferral is still valid, and the Company's application meets the requirements of ORS 757.259 and OAR 860-027-0300. For these reasons, Staff recommends PGE's application be approved.

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PROPOSED COMMISSION MOTION:

PGE's application be approved for the 12-month period beginning January 1, 2015.

PGE 1514(4) ADR Program deferral

ITEM NO. CA9

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: January 26, 2016

REGULAR ____ **CONSENT** X **EFFECTIVE DATE** **January 1, 2016**

DATE: January 7, 2016

TO: Public Utility Commission

FROM: Judy Johnson JJ

THROUGH: Jason Eisdorfer and Marc Hellman

SUBJECT: PORTLAND GENERAL ELECTRIC: (Docket No. UM 1514(5)) Requests reauthorization to defer the incremental costs associated with Automated Demand Response.

STAFF RECOMMENDATION:

I recommend that Portland General Electric's (PGE or Company) application be approved for the 12-month period beginning January 1, 2016.

ISSUE:

PGE requests reauthorization to defer, with interest, the incremental costs associated with the Automated Demand Response Pilot (ADR Pilot), for later recovery in rates.

APPLICABLE RULES AND LAWS:

PGE seeks deferred accounting under ORS 757.259(2)(e), and OAR 860-027-0300(3). Previous approval of this deferral was most recently granted by Order No. 15-022.

ANALYSIS:

The deferral of incremental ADR costs, as an automatic adjustment clause, and the associated cost recovery tariff (Advice 10-29, Schedule 135) were initially authorized by Commission Order No. 11-82, as part of a two-year pilot program. The Commission has authorized PGE to defer the incremental ADR costs each year since 2011.

PGE seeks reauthorization for a deferral of incremental costs associated with the ADR Program and the new Pilot timeline for the period January 1, 2016, through December 31, 2016.

First ADR Pilot Period

PGE selected a third-party provider based on a combination of good credit, bidding summer and winter events, better technology, and a stronger marketing plan. The provider began its program marketing on September 1, 2011, but failed to meet the initial capacity milestone of 5 MW for the first winter season. The provider then began to experience financial difficulties and failed to meet additional terms of its agreement for the ADR pilot. On April 30, 2012, PGE terminated its contract with the provider.

New Proposed ADR Pilot Period

Although the first program was terminated, PGE believed that ADR pilot could still be a valuable and viable resource. Consequently, PGE selected a new provider and implemented a new pilot. PGE proposed that the new ADR pilot period run through June 2015. This will allow four operating seasons (two full years) to be evaluated for performance and cost effectiveness with the evaluation to be completed by April 2015. If the evaluation is favorable, the second period will run through 2016, which will allow a second evaluation to review the entire pilot with the evaluation to be completed by April 2016. If the second evaluation is favorable, PGE will submit the ADR as an on-going capacity resource in its Annual Power Cost Update (Schedule 125) and Power Cost Adjustment Mechanism (Schedule 126) similar to other power cost and capacity items.

Description of Amounts

Pursuant to ORS 757.259(2)(e), PGE seeks renewal of deferred accounting treatment for the incremental costs associated with an ADR. The approval of the Application will also enable the continued use of an automatic adjustment clause rate schedule which will provide for recovery of the incremental costs associated with the ADR through tariff Schedule 135.

Reasons for Deferral

Pursuant to ORS 757.259(2)(e), PGE seeks to continue a deferred accounting treatment for the incremental costs associated with the ADR (initially authorized by the Commission through Order No. 11-082 on June 1, 2011). The granting of this reauthorization application will minimize the frequency of rate changes and match appropriately the costs borne by, and benefits received by, customers.

Proposed Accounting

PGE proposes to record the deferred costs in FERC account 182.3 (Regulatory Assets), with the offsetting credit recorded to FERC account 131 (Cash).

Estimate of Amounts

PGE estimates the amounts to be deferred in 2016 to be approximately $2.3 million.

Information Related to Future Amortization

- Earnings review – An earnings review does not apply to an automatic adjustment clause, pursuant to ORS 757.259(5). If the pilot program is deemed successful, PGE proposes that subsequent costs to flow through PGE's Annual Power Cost Update (Schedule 125) and Power Cost Adjustment Mechanism (PCAM) (Schedule 126) for the year 2017, and would be subject to the earnings review contained within the PCAM.

- Prudence Review – A prudence review should include a verification that deferred amounts are incremental, and verification of the accounting methodology used to determine the final amortization balance.

- Sharing – If the ADR is deemed successful, then the proposal is for subsequent costs to flow through PGE's Annual Power Cost Update (Schedule 125) and Power Cost Adjustment Mechanism (PCAM) (Schedule 126). The PCAM is subject to the dead bands and sharing percent's as specified by Commission Order Nos. 07-015 and 10-478.

- Rate Spread/Design – Per Commission Order No. 11-517, tariff Schedule 135 will allocate the costs of the ADR on the basis of an equal percent of forecast generation revenues.

- Three Percent Test (ORS 757.259(6)) – The three percent test measures the annual overall average effect on customer rates resulting from deferral amortizations. The three percent test limits (exceptions at ORS 757.259(7) and (8)) the aggregated deferral amortizations during a 12-month period to no more than three percent of the utility's gross revenues for the preceding year. Because PGE is an electric utility, ORS 757.259(8) allows the Commission to consider up to a six percent limit.

Staff Analysis

The rationale for this deferral is still valid, and the Company's application meets the requirements of ORS 757.259 and OAR 860-027-0300. For these reasons, Staff recommends PGE's application be approved.

PROPOSED COMMISSION MOTION:

PGE's application be approved for the 12-month period beginning January 1, 2016.

ITEM NO. CA9

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: March 7, 2017

REGULAR ____ **CONSENT** __X__ **EFFECTIVE DATE** __January 1, 2017__

DATE: February 28, 2017

TO: Public Utility Commission

FROM: Mitchell Moore MPM

THROUGH: Jason Eisdorfer and Marc Hellman

SUBJECT: PORTLAND GENERAL ELECTRIC: (Docket No. UM 1514(6)) Requests reauthorization to defer the incremental costs associated with Automated Demand Response.

STAFF RECOMMENDATION:

I recommend that Portland General Electric's (PGE or Company) application for reauthorization to defer, with interest, the incremental costs associated with the Automated Demand Response Pilot (ADR Pilot), be approved for the 12-month period beginning January 1, 2017.

DISCUSSION:

Issue

Whether the Commission should approve PGE's request for reauthorization to defer, with interest, the incremental costs associated with the Automated Demand Response Pilot, for later recovery in rates.

Applicable Rule or Law

PGE submitted its deferral application on December 15, 2016, pursuant to ORS 757.259 and OAR 860-027-0300. ORS 757.259 provides the Commission with authority to authorize the deferral of utility revenues and expenses for later inclusion in rates. OAR 860-027-0300 are the Commission's rule governing the use of deferred accounting by energy and large telecommunications utilities. Previous approval of this deferral was most recently granted by Order No. 16-111.

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Analysis

Background
The deferral of incremental ADR costs and recovery through an automatic adjustment clause (Schedule 135) were initially authorized by Commission Order No. 11-182, as part of a two-year pilot program. The Commission has authorized PGE to defer the incremental ADR costs each year since 2011.

PGE seeks reauthorization to defer incremental costs associated with the ADR Program and the new Pilot timeline for the period January 1, 2017, through December 31, 2017.

First ADR Pilot Period
PGE selected a third-party provider based on a combination of good credit, bidding summer and winter events, better technology, and a stronger marketing plan. The provider began its program marketing on September 1, 2011, but failed to meet the initial capacity milestone of 5 MW for the first winter season. The provider then began to experience financial difficulties and failed to meet additional terms of its agreement for the ADR pilot. On April 30, 2012, PGE terminated its contract with the provider.

New Proposed ADR Pilot Period
As discussed in PGE's report submitted with the second ADR evaluation on April 28, 2016, the pilot in its current form has fallen short of its nomination goal of 25 MW, with 11 MW expected to be nominated for the winter of 2016-2017. Additionally, PGE's contract with EnerNOC, the program's third-party provider, expires at the end of this year. These two factors have led both PGE and EnerNOC to explore adjustments to the program that may lead to greater success. While PGE and EnerNOC have not decided on the exact changes to take place, they expect that changes will include expanding offerings to medium-sized customers, flexibility in nomination windows, and potentially reaching out to other vendors to supplement EnerNOC. Because the ADR pilot continues to be in transition, PGE proposes to continue its deferred accounting and not move it into power costs as a capacity resource until it stabilizes as a program.

Description of Amounts
Pursuant to ORS 757.259(2)(e), PGE seeks renewal of deferred accounting treatment for the incremental costs associated with the ADR pilot. The approval of the Application will also enable the continued use of an automatic adjustment clause rate schedule which will provide for recovery of the incremental costs associated with the ADR through tariff Schedule 135.

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Reasons for Deferral
Pursuant to ORS 757.259(2)(e), PGE seeks to continue deferred accounting treatment for the incremental costs associated with the ADR (initially authorized by the Commission through Order No. 11-182 on June 1, 2011). The granting of this reauthorization application will minimize the frequency of rate changes and match appropriately the costs borne by, and benefits received by, customers.

Proposed Accounting
PGE proposes to record the deferred costs in FERC account 182.3 (Regulatory Assets), with the offsetting credit recorded to FERC account 131 (Cash).

Estimate of Amounts
PGE estimates the amounts to be deferred in 2017 to be approximately $1.4 million.

Information Related to Future Amortization

- Earnings review – An earnings review does not apply to an automatic adjustment clause, pursuant to ORS 757.259(5). If the pilot program is deemed successful, PGE proposes to have costs of the ADR program flow through PGE's Annual Power Cost Update (Schedule 125) and Power Cost Adjustment Mechanism (PCAM) (Schedule 126) for the year 2018, and be subject to the earnings review contained within the PCAM.

- Prudence Review – A prudence review should include a verification that deferred amounts are incremental, and verification of the accounting methodology used to determine the final amortization balance.

- Sharing – If the ADR is deemed successful, then the proposal is for subsequent costs to flow through PGE's Annual Power Cost Update (Schedule 125) and Power Cost Adjustment Mechanism (PCAM) (Schedule 126). The PCAM is subject to the dead bands and sharing percent's as specified by Commission Order Nos. 07-015 and 10-478.

- Rate Spread/Design – Per Commission Order No. 11-517, tariff Schedule 135 will allocate the costs of the ADR on the basis of an equal percent of forecast generation revenues.

- Three Percent Test (ORS 757.259(6)) – The three percent test measures the annual overall average effect on customer rates resulting from deferral amortizations. The three percent test limits (exceptions at ORS 757.259(7) and (8)) the aggregated deferral amortizations during a 12-month period to no more than three percent of the utility's gross revenues for the preceding year. Because PGE is an electric utility, ORS 757.259(8) allows the Commission to consider up to a six percent limit.

Conclusion

The rationale for this deferral is still valid, and the Company's application meets the requirements of ORS 757.259 and OAR 860-027-0300. For these reasons, Staff recommends PGE's application be approved.

PROPOSED COMMISSION MOTION:

Approve PGE's application for reauthorization to defer the incremental costs associated with the Automated Demand Response Pilot (ADR Pilot), for the 12-month period beginning January 1, 2017.

ITEM NO. CA7

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: October 24, 2017

REGULAR ____ CONSENT X EFFECTIVE DATE January 1, 2018 (Deferral Authorization)

DATE: **October 10, 2017**

TO: Public Utility Commission

FROM: Jason R. Salmi Klotz JK

THROUGH: Jason Eisdorfer, JP Batmale, and John Crider
JBB for JE JBB JC

SUBJECT: PORTLAND GENERAL ELECTRIC: (UM 1514(7)) Application for Reauthorization of Deferral of Incremental Costs Associated with Non-Residential Demand Response and request for approval of program modifications.

STAFF RECOMMENDATION:

1) Approve pilot program modifications proposed by PGE with requirements for additional revisions and reports recommended by Staff.

2) Portland General Electric's (PGE or Company) application for reauthorization to defer, with interest, the incremental costs associated with the Automated Demand Response Pilot (ADR Pilot), be approved for the 12-month period beginning January 1, 2018.

3) Approve Portland General Electric Company's proposal to implement Non-Residential Demand Response Pilots to replace the current Auto-Demand Response pilot and PGE's Schedule 77, Firm Load Reduction Program.

DISCUSSION:

Issue

Whether the Commission should approve PGE's request for reauthorization to defer, with interest, the incremental costs associated with the Automated Demand Response Pilot, for later recovery in rates.

Additionally, whether to approve PGE's request for approval to implement the Non-Residential DR Pilots to replace the current ADR pilot and PGE's Schedule 77, Firm Load Reduction Program. The revised program proposal becomes two related programs to be formalized through the subsequent submittal of Schedule 25, Nonresidential Direct Load Control Pilot and Schedule 26, Non-residential Demand Response Pilots.

The projected estimated costs PGE seeks for deferral over three years of the pilot programs is roughly $10,793,407. PGE has submitted a cost effectiveness analysis of the program over its anticipated 5 year life showing a total resource cost of 1.03.

Applicable Rule

The deferral of incremental ADR costs and recovery through an automatic adjustment clause (Schedule 135) were initially authorized by Commission Order No. 11-182, as part of a two-year pilot program PGE submitted its deferral application on September 21, 2017, pursuant to ORS 757.259 and OAR 860-027-0300. ORS 757.259 provides the Commission with authority to authorize the deferral of utility revenues and expenses for later Inclusion in rates. OAR 860-027-0300 are the Commission's rule governing the use of deferred accounting by energy and large telecommunications utilities. Previous approval of this deferral was most recently granted by Order No. 17-105.

Analysis

Background:
The deferral of incremental ADR costs and recovery through an automatic adjustment clause (Schedule 135) were initially authorized by Commission Order No. 11-182, as part of a two-year pilot program. The Commission has authorized PGE to defer the incremental ADR costs each year since 2011. PGE seeks reauthorization to defer incremental costs associated with the ADR Program and the new Pilot timeline for the period January 1, 2018 through December 31, 2018.

Reason for Proposal of Program Revision and Deferral
Normally, Staff would review a request to modify a pilot program separately from a requested cost deferral. However, time was of the essence in this case as PGE needed the approval of the program revisions prior to the demand response season beginning in November 1. PGE was unable to submit a program revision request sooner due to the fact that EnerNoc, the entity previously under contract to administer the program, abruptly left the Pacific Northwest market this summer. To keep current customers enrolled, for program continuity, and to forgo possible additional marketing costs to re-

engage current participants, PGE needed approval of the program revision in time to implement the changes before the next winter demand response season. Given the Commission's public meeting calendar PGE needed to submit the deferral request along with program revisions. Staff has analyzed the proposed revisions and met with PGE Staff to assure Staff fully understood the implication of the requested programmatic revisions.

Description of Amounts:
Pursuant to ORS 757.259(2)(e), PGE seeks renewal of deferred accounting treatment for the incremental costs associated with the ADR pilot. The approval of the Application will also enable the continued use of an automatic adjustment clause rate schedule which will provide for recovery of the incremental costs associated with the ADR through tariff Schedule 135.

Reasons for Deferral:
Pursuant to ORS 757.259(2)(e), PGE seeks to continue deferred accounting treatment for the incremental costs associated with the ADR (initially authorized by the Commission through Order No. 11-182 on June 1, 2011). The granting of this reauthorization application will minimize the frequency of rate changes and match appropriately the costs borne by, and benefits received by, customers.

Proposed Accounting:
PGE proposes to record the deferred costs in FERC account 182.3 (Regulatory Assets), with the offsetting credit recorded to FERC account 131 (Cash).

Estimate of Amounts:
PGE estimates the amounts to be deferred in 2018 to be approximately $2,345,271. Prior deferral amounts varied from $3M a year during the first two years of the program to recently an estimated $1.4M in 2017 due in large part to lower than expected program participation. PGE has been able to demonstrate a cost effectiveness score of 1.03 with the revised program structure. The requested $2.34M seems in line with the expected participation increase as well as the additional costs of operating the program internal to PGE.

Information Related to Future Amortization:

- Earnings review-An earnings review does not apply to an automatic adjustment clause, pursuant to ORS 757.259(5). If the pilot program is deemed successful, PGE proposes to have costs of the ADR program flow through PGE's Annual Power Cost Update (Schedule 125) and Power Cost Adjustment Mechanism (PCAM) (Schedule 126) for the year 2019, and be subject to the earnings review contained within the PCAM.

- Prudence Review-A prudence review should include a verification that deferred amounts are incremental, and verification of the accounting methodology used to determine the final amortization balance.

- Sharing - If the ADR is deemed successful, then the proposal is for subsequent costs to flow through PGE's Annual Power Cost Update (Schedule 125) and Power Cost Adjustment Mechanism (PCAM) (Schedule 126). The PCAM is subject to the dead bands and sharing percentages as specified by Commission Order Nos. 07-015 and 10-478.

- Rate Spread/Design - Per Commission Order No. 11-517, tariff Schedule 135 will allocate the costs of the ADR on the basis of an equal percent of forecast generation revenues.

- Three Percent Test (ORS 757.259(6)) - The three percent test measures the annual overall average effect on customer rates resulting from deferral amortizations. The three percent test limits (exceptions at ORS 757.259(7) and (8)) the aggregated deferral amortizations during a 12-month period to no more than three percent of the utility's gross revenues for the preceding year. Because PGE is an electric utility, ORS 757.259(8) allows the Commission to consider up to a six percent limit.

First ADR Pilot Period:
PGE selected a third-party provider based on a combination of good credit, bidding summer and winter events, better technology, and a stronger marketing plan. The provider began its program marketing on September 1, 2011, but failed to meet the initial capacity milestone of 5 MW for the first winter season. The provider then began to experience financial difficulties and failed to meet additional terms of its agreement for the ADR pilot. On April 30, 2012, PGE terminated its contract with the provider.

New Proposed ADR Pilot Period:
As discussed in PGE's report submitted with the second ADR evaluation on April 28, 2016, the pilot in its current form has fallen short of its nomination goal of 25 MW, with 11 MW nominated for the winter of 2016-2017. Additionally, PGE's contract with EnerNOC, the program's third-party provider has expired. In addition, PGE's EnerNOC informed PGE earlier this year that they were leaving the Pacific Northwest market and that as of September 30, 2017, they would be terminating their contract to provide the aggregator demand response (DR) services under the ADR pilot.

Program Revisions for 2017 - 2020:

PGE has taken this opportunity to review the existing ADR pilot along with Schedule 77 and revised them so as to create two pilots able to meet PGE's goals of greater than 27 MW of peak load reduction by 2021 across all nonresidential segments and products.

The new pilots are based upon the results of the Energy Partner evaluations conducted by Itron (provided previously under Docket No. UM 1514), market research from Hansa customer interviews, focus groups, and Navigant report. Across that research, some common themes emerged:

- No one offer will suffice for all customers. Thus, PGE needs to provide a variety of offerings.
- There needs to be more flexibility in programs:
    - Important segments of our customer base (particularly in the commercial sector) are underserved;
    - There are opportunities for additional demand response from direct access customers who are not eligible for this program; and
    - Offerings need to better address customer business needs.

PGE believes that conducting these revisions to its ADR pilot program including a commercial sector component, memorialized in a subsequent filing of Schedule 25 and Schedule 26, will enable the pilot to be successful and will help PGE meet the capacity deficient identified in their 2016 IRP as well as making progress toward meeting their demand response acquisition goals.

Staff agrees that the alterations made to the ADR program to better leverage the prospects of industrial demand response and explore the demand response capacity available in the commercial sector are reasonable and structured such that success can reasonably be expected.

In contrast to the previous ADR program, the proposed pilots will be administered directly by PGE to its customers, with support from a program implementer and a technology integrator/demand response management system (DRMS) provider. Staff has come to understand through discussion with PGE technical and project management staff the DRMS investment made here will augment this program, should success materialize, and be utilized for additional demand response programs. Additionally, the provider of the DRMS technology is the same company constructing the DRMS for PGE's smart water heater pilot program.

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Because PGE will now be administering the program, it gives PGE and its implementer the ability to better bundle and/or cross-market the program with other offerings, such as energy efficiency, renewables, storage, and dispatchable standby generation.

The new program design and its accompanying tariffs will open up new opportunities to expand the market. Existing and new customers that were previously averse to the long availability windows (10 hours under EnerNOC) and/or short notification window (10 minutes previously) will be able to have increased capacity commitments under less onerous conditions. Small and medium-sized businesses will be able to participate through either a turnkey thermostat offering or through the curtailable tariff with the flexibility that meets their needs. Campuses, a historically underserved market segment, will be able to aggregate their meters to participate without having to incur significant up-front costs across numerous smaller sites.

Program Evaluations:
PGE will submit two pilot evaluations to the Commission and stakeholders:

- The first evaluation will be submitted during the third quarter of 2019, after the first three operating seasons. This will allow for adequate time and events to provide meaningful results.
- A final evaluation will be submitted in the second quarter of 2021, after the next three operating seasons and the planned end of the pilots.

The evaluations will include various metrics on customer participation, demand response capacity, and data gaps that emerge from the program. In order to ensure that we have results to evaluate, even during seasons with mild weather or minimal need for DR curtailment, PGE will call a minimum of one event per agreement year. PGE will call a minimum of one event per agreement year.

Recommended Revisions and Reporting Requirements:
Staff recommends the following revisions to the program and recommends the utility submit the following updates to Commission Staff:

Updates required before submittal of Schedules 25 and 26 for Commission approval:

- In order to be successful Staff expects PGE's program outreach, marketing and contracting efforts with customers will include much more detailed information about how the program operates particularly around event call, event durations, incentive and participation requirements. To this end Staff requests PGE submit draft copies of the marketing material and customer engagement protocols to be used by PGE and its program implementers.

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- A detailed discussion of the baseline methodology to be used in the program, and thorough discussion elucidating how PGE defines and will use “the last typical operational days” in their baseline calculation methodology, complete with demonstrative examples.

Updates required subsequent to program roll-out:

- PGE must keep on file, and be ready to submit copies of, all contracts signed by participating customers;
- Each quarter PGE will submit to Staff an informational filing containing a spreadsheet of each participating customers nominated load and event performance. PGE may redact identifying information if necessary or file as confidential.

Updates required within one year of program approval:

- Staff suspects that PGE may be overly conservative in the application of their de-rate factor when calculating program cost effectiveness and believe that such a conservative approach may be hindering PGE’s willingness to invest in resources to bring about additional demand response program proposals. While clear direction on calculating demand response has not been given to PGE it is important that PGE, the Commission, and stakeholders continue to iterate until such time as the Commission has the capacity to comprehensively address demand response cost effectiveness. Therefore, Staff recommends PGE do run their loss of load probability, Renewable Energy Capacity Planning (RECAP), model with the demand response parameters. In response to the Commission Order in this docket, in order to more accurately identify a directly applicable de-rate factor, PGE should submit a timeline for the recommended modeling run. If PGE finds that the modeling run cannot take place within one year’s time, PGE must submit an informational filing to the Commission delineating in detail an alternative methodology for calculating the de-rate factor.
- Staff would like to open an exploratory discussion with PGE about the feasibility and possible design of a Critical Peak Pricing Program for large industrial customers. Staff currently believes that rate design is a more elegant and cost effective approach to demand response and ultimately would like to see more customers transitioned to dynamic rates as our collective understanding and experience with demand response evolves.

Relation to the Demand Response Test Bed:
In Docket LC 66, PGE’s 2016 Integrated Resource Plan this Commission approved the Staff’s proposal for the creation of a Demand Response Test Bed. While discussions with PGE and Staff and the formation of the Demand Response Review Committee have, at this early date, not taken place, Staff does not envision these

programs proposed here to be formally Test Bed pilots. Depending on the placement of PGE's Test Bed or Beds customers participating in the programs proposed here may be present and thus factor into any high penetration or saturation scenarios and thus inform performance, programmatic and saturation studies. However, because we have yet to detail the Demand Response Test Bed with PGE and others, Staff does not view these programs as currently or explicitly part of the Test Bed. One of the reasons for the development of Demand Response Test Bed was to accelerate PGE's pilot to program timeline and PGE's demand response resource acquisition. At present Staff believes the pilot period contemplated for these two programs is reasonable and can reasonably envision successful transfer to a full program after the pilot period.

Conclusion

The rationale for this deferral is still valid, and the Company's application meets the requirements of ORS 757.259 and OAR 860-027-0300. For these reasons, Staff recommends PGE's application be approved. Staff also recommends the Commission adopt Staff's recommendations regarding additional program revisions and reporting requirements found herein.

PROPOSED COMMISSION MOTION:

Recommend that Portland General Electric's (PGE or Company) application for reauthorization to defer, with interest, the incremental costs associated with the Automated Demand Response Pilot (ADR Pilot), be approved for the 12-month period beginning January 1, 2017.

Recommend approval of Portland General Electric Company's proposal to implement Non-Residential Demand Response Pilots to replace the current Auto-Demand Response pilot and PGE's Schedule 77, Firm Load Reduction Program.

Approve program pilot program proposed by PGE with requirements for additional revision and reports recommended by Staff.

ITEM NO. CA4

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: April 23, 2019

REGULAR ____ **CONSENT** __X__ **EFFECTIVE DATE** __**January 1, 2019**__

DATE: April 16, 2019

TO: Public Utility Commission

MDM JPB for TF

FROM: Mitchell Moore and Thomas Familia

EPh JPB

THROUGH: Jason Eisdorfer and JP Batmale

SUBJECT: PORTLAND GENERAL ELECTRIC: (UM 1514(8)) Application for Reauthorization of Deferral of Incremental Costs Associated with Non-Residential Demand Response Pilots.

STAFF RECOMMENDATION:

Approve Portland General's (PGE or Company) application for reauthorization to defer, with interest, the incremental costs associated with the Automated Demand Response Pilot (ADR Pilot) for the 12-month period beginning January 1, 2019.

DISCUSSION:

Issue

Whether the Public Utility Commission of Oregon (OPUC or Commission) should approve PGE's request for reauthorization to defer, with interest, the incremental costs associated with the Automated Demand Response (ADR) Pilot, for later recovery in rates.

Applicable Law

The deferral of incremental ADR costs and recovery through an automatic adjustment clause (Schedule 135) were initially authorized by Commission Order No. 11-182, as part of a two-year pilot program. PGE submitted its deferral application on December 20, 2018, pursuant to ORS 757.259 and OAR 860-027-0300. ORS 757.259 provides the Commission with authority to authorize the deferral of utility revenues and expenses for later Inclusion in rates. OAR 860-027-0300 are the Commission's rule governing the

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use of deferred accounting by energy and large telecommunications utilities. Previous approval of this deferral was most recently granted by Order No. 17-429.

Analysis

Background
The deferral of incremental ADR costs and recovery through an automatic adjustment clause (Schedule 135) were initially authorized by Commission Order No. 11-182, as part of a two-year pilot program. The Commission has authorized PGE to defer these each year since 2011. PGE seeks reauthorization with this filing for the period January 1, 2019 through December 31, 2019.

Description of Amounts
Amounts requested for deferral include administration, vendor and equipment costs related to the pilot, as well as incentive payments to program participants.

Reasons for Deferral
Pursuant to ORS 757.259(2)(e), PGE seeks to continue deferred accounting treatment for the incremental costs associated with the ADR pilot. The granting of this reauthorization application will minimize the frequency of rate changes and match appropriately the costs borne by, and benefits received by, customers.

Proposed Accounting
PGE proposes to record the deferred costs in FERC account 182.3 (Regulatory Assets), with the offsetting credit recorded to FERC account 131 (Cash).

Estimate of Amounts
PGE estimates the amounts to be deferred in 2019 to be approximately \$3.1 million. Prior deferral amounts varied from \$3M a year during the first two years of the program, an estimated \$1.4M in 2017 - due in large part to lower than expected program participation - to an estimated \$2.7M in 2018.

Information Related to Future Amortization

- Earnings review - An earnings review does not apply to an automatic adjustment clause, pursuant to ORS 757.259(5). If the pilot program is deemed successful, PGE proposes to have costs of the ADR program flow through PGE's Annual

Power Cost Update (Schedule 125) and Power Cost Adjustment Mechanism (PCAM) (Schedule 126), and be subject to the earnings reviewed contained within the PCAM.

- Prudence Review - A prudence review should include a verification that deferred amounts are incremental, and verification of the accounting methodology used to determine the final amortization balance.

- Sharing - if the ADR is deemed successful, then the proposal is for subsequent costs to flow through PGE's Annual Power Cost Update (Schedule 125) and Power Cost Adjustment Mechanism (PCAM) (Schedule 126). The PCAM is subject to the dead bands and sharing percentages as specified by Commission Order Nos. 07-015 and 10-478.

- Rate Spread/Design - Per Commission Order No. 11-517, tariff Schedule 135 will allocate the costs of the ADR on the basis of an equal percent of forecast generation revenues.

- Three Percent Test (ORS 757.259(6)) - The three percent test measures the annual overall average effect on customer rates resulting from deferral amortizations. The three percent test limits (exceptions at ORS 757.259(7) and (8)) the aggregated deferral amortizations during a 12-month period to no more than three percent of the utility's gross revenues for the preceding year. Because PGE is an electric utility, ORS 757.259(8) allows the Commission to consider up to a six percent limit.

First ADR Pilot Period
PGE selected a third-party provider based on a combination of good credit, bidding summer and winter events, better technology, and a stronger marketing plan. The provider began its program marketing on September 1, 2011, but failed to meet the initial capacity milestone of 5 MW for the first winter season. The provider then began to experience financial difficulties and failed to meet additional terms of its agreement for the ADR pilot. On April 30, 2012, PGE terminated its contract with the provider.

Second ADR Pilot Period
As discussed in PGE's report submitted with the second ADR evaluation on April 28, 2016, the pilot in its second form fell short of its nomination goal of 25 MW, with 11 MW nominated for the winter of 2016-2017. Additionally, PGE's contract with EnerNOC, the program's third-party provider expired. EnerNOC informed PGE that they were leaving the Pacific Northwest market and they would be terminating their contract to provide the

aggregator demand response (DR) services under the ADR pilot as of September 30, 2017.

Current ADR Pilot Period (2017 - 2020)
In contrast to the first two stages of the ADR program, PGE's current pilots are administered directly by the Company to its customers, with support from a program implementer and a technology integrator/demand response management system (DRMS) provider.

PGE revised the ADR pilot, along with Schedule 77, to create two pilots towards meeting PGE's goals of greater than 27 MW of peak load reduction by 2021 across all nonresidential segments and products. The Non-Residential Direct Load Control (DLC) Pilot, Schedule 25, provides Commercial customers with a more easily deployed DLC program. The Non-Residential Pricing Pilot, Schedule 26, resembles Schedule 77 but offers customers a larger variety of offerings based upon the results of the Energy Partner evaluations conducted by Itron (provided previously under Docket No. UM 1514), market research from Hansa customer interviews, focus groups, and Navigant report.

As provided in the table below, PGE called one winter and six summer non-residential DR events in 2018. As a whole, event performance came in above PGE nominations in the summer and below the nomination in the winter.

Table 1: 2018 PGE Non-Residential Demand Response Events

2018 PGE Non-Residential Demand Response Events		
	Nomination (MW)	Event Performance (MW)
Winter Event	3.4	2.7
Summer Event #1	11.6	13.6
Summer Event #2	11.6	13.2
Summer Event #3	9.9	10.9
Summer Event #4	9.9	11.4
Summer Event #5	9.9	9.4
Summer Event #6	9.9	8.6

Program Evaluations
PGE will submit two pilot evaluations to the Commission and stakeholders:

- The first evaluation will be submitted during the third quarter of 2019, after the first three operating seasons. This will allow for adequate time and events to provide meaningful results.

- A final evaluation will be submitted in the second quarter of 2021, after the next three operating seasons and the anticipated end of the pilots.

The evaluations will include various metrics on customer participation, demand response capacity, and data gaps that emerge from the program. In order to ensure that we have results to evaluate, even during seasons with mild weather or minimal need for DR curtailment, PGE will call a minimum of one event per agreement year.

Staff would note that the most recent results from the two ADR pilots appear to be very promising. After nearly a decade of testing approaches to DR for non-residential customers, this set of DR pilots are maturing into successful programs that are competently executed and well-received by customers (i.e., response rates to events). To this end, PGE will receive a full evaluation of the pilots' first three operating seasons in the fall of 2019. The time would seem to be ripe to discuss how we transition successful DR pilots into full-fledged programs that could be folded into rate base.

Conducting such a transition soon will be important for several reasons. First, PGE has a large portfolio of DR pilots and is making a substantial investment in its innovative DR Testbed. We need to work together to develop a regulatory pathway for successful pilots to become normalized programs. Second, state law requires that PGE treat cost effective DR as a resource to be acquired prior to new generation. The sooner DR is "normalized" and moved beyond the pilot/deferral process, the sooner DR can be equally treated as a resource option. . Lastly, PGE's long-term planning calls for ever increasing amounts of DR. From the draft 2019 IRP and its 200 MW of summer DR to the 2018 decarbonization pathway study which highlighted the need very large amounts of flexible end-use load by 2035, PGE needs DR to become a normal part of business and planning process, much as energy efficiency has become.

Recommended Revisions and Reporting Requirements
Staff recommends the following revisions to the program and recommends the utility submit the following updates to Commission Staff:

- PGE must keep on file, and be ready to submit copies of, all contracts signed by participating customers;

- Each quarter PGE will submit to Staff an informational filing containing a spreadsheet of each participating customers nominated load and event performance. PGE may redact identifying information if necessary or file as confidential.

- PGE will run their loss of load probability, Renewable Energy Capacity Planning (RECAP), model with demand response parameters.[1]
    - Staff suspects that PGE may be overly conservative in the application of their derate factor when calculating program cost effectiveness and believes that such a conservative approach may be hindering PGE's willingness to invest in resources to bring about additional demand response program proposals. To note, as can be seen in Table 1 above, participants outperformed PGE's nominations in two-thirds of 2018 DR events. While clear direction on calculating demand response has not been given to PGE it is important that PGE, the Commission, and stakeholders continue to iterate until such time as the Commission has the capacity to comprehensively address demand response cost effectiveness.
    - On February 13, 2019, in response to Commission Order No. 17-429 in this docket, PGE submitted an informational filing stating that the Company plans to run RECAP in support of its 2019 IRP, with results available by August 8, 2019 as part of its IRP filing. Unfortunately, the timing of the IRP release has changed since PGE's February filing in UM 1514. PGE now plans to release the IRP in June, not August. Staff requests that PGE inform Staff if the RECAP run has already occurred and shared with the IRP team. If so, Staff would like to see the results. If not, Staff would request that the RECAP run take place as soon as possible so as to help inform its 2019 IRP filing.

- Improved communication with Staff relating to this pilot's deliverables, as well as the level of detail provided therein.
    - As an example, while Staff appreciates that PGE has committed to run RECAP in support of its 2019 IRP, the Company's submittal of the informational filing to the Commission delineating the details as such was 1) not provided within the one year timeline as set forth in Commission Order No. 17-429 and 2) as the 2019 IRP results fall outside of the one year timeline, did not provide an alternative methodology for calculating the de-rate factor during the interim.

- By November 1st, 2019 PGE to hold a workshop with Staff and stakeholders to present and discuss the findings of the pilot evaluation and outline a plan for how this nearly decade old pilot could be transitioned into full program.

[1] For a description of the methodology see UM 1708, PGE's Compliance to Order No. 15-203 (April 28, 2016): Navigant - A Proposed Cost-Effectiveness Approach for Demand Response.

Conclusion

Staff reviewed PGE's application and supporting program work papers. In previous deferral applications, PGE has demonstrated a cost effectiveness score of 1.03 with the revised program structure now internal to the Company.[2] In addition, the requested $3.1M for 2019 appears consistent with the expected participation and costs of operating the program internal to PGE.

The rationale for this deferral is still valid, and the Company's application meets the requirements of ORS 757.259 and OAR 860-027-0300. For these reasons, Staff recommends PGE's application be approved.

PROPOSED COMMISSION MOTION:

Approve Portland General Electric's (PGE or Company) application for reauthorization to defer, with interest, the incremental costs associated with the Automated Demand Response Pilot (ADR Pilot), be approved for the 12-month period beginning January 1, 2019.

PGE UM 1514 Deferral

[2] See UM 1514, PGE's Supplemental Application, Attachment C, Dated 9/21/2017

ITEM NO. CA6

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: August 11, 2020

REGULAR ____ CONSENT _X_ EFFECTIVE DATE January 1, 2020

DATE: August 3, 2020

TO: Public Utility Commission

FROM: Mitchell Moore and Nick Sayen

THROUGH: Bryan Conway, John Crider, and Matt Muldoon **SIGNED**

SUBJECT: PORTLAND GENERAL ELECTRIC:
(UM 1514(9))
Application for Reauthorization of Deferral of Incremental Costs Associated with Non-Residential Demand Response Pilots.

STAFF RECOMMENDATION:

Approve Portland General Electric's (PGE or Company) application for reauthorization to defer, with interest, the incremental costs associated with the Automated Demand Response Pilot (ADR Pilot) for the 12-month period beginning January 1, 2020.

DISCUSSION:

Issue

Whether the Public Utility Commission of Oregon (OPUC or Commission) should approve PGE's request for reauthorization to defer, with interest, the incremental costs associated with the Automated Demand Response Pilot, for later recovery in rates.

Applicable Law

The deferral of incremental ADR costs and recovery through an automatic adjustment clause (Schedule 135) were initially authorized by Commission Order No. 11-182, as part of a two-year pilot program. PGE submitted its deferral application on December 20, 2018, pursuant to ORS 757.259 and OAR 860-027-0300.
ORS 757.259 provides the Commission with authority to authorize the deferral of utility revenues and expenses for later Inclusion in rates. OAR 860-027-0300 are the Commission's rule governing the use of deferred accounting by energy and large

telecommunications utilities. Previous approval of this deferral was most recently granted by Order No. 19-151.

Analysis

Background
The deferral of incremental ADR costs and recovery through an automatic adjustment clause (Schedule 135) were initially authorized by Commission Order No. 11-182, as part of a two-year pilot program. The Commission has authorized PGE to defer these each year since 2011. PGE seeks reauthorization with this filing for the period January 1, 2020 through December 31, 2020.

Description of Amounts
Amounts requested for deferral include administration, vendor and equipment costs related to the pilot, as well as incentive payments to program participants.

Reasons for Deferral
Pursuant to ORS 757.259(2)(e), PGE seeks to continue deferred accounting treatment for the incremental costs associated with the ADR pilot. The granting of this reauthorization application will minimize the frequency of rate changes and match appropriately the costs borne by, and benefits received by, customers.

Proposed Accounting
PGE proposes to record the deferred costs in FERC account 182.3 (Regulatory Assets), with the offsetting credit recorded to FERC account 131 (Cash).

Estimate of Amounts
PGE estimates the amounts to be deferred in 2020 to be approximately $3.7 million. Prior deferral amounts varied from $3M a year during the first two years of the program, an estimated $1.4M in 2017 – due in large part to lower than expected program participation - to an estimated $3.1M in 2019.

Information Related to Future Amortization:

- Earnings review – An earnings review does not apply to an automatic adjustment clause, pursuant to ORS 757.259(5). If the pilot program is deemed successful, PGE proposes to have costs of the ADR program flow through PGE's Annual

Power Cost Update (Schedule 125) and Power Cost Adjustment Mechanism (PCAM) (Schedule 126), and be subject to the earnings reviewed contained within the PCAM.

- Prudence Review – A prudence review should include a verification that deferred amounts are incremental, and verification of the accounting methodology used to determine the final amortization balance.

- Sharing – if the ADR is deemed successful, then the proposal is for subsequent costs to flow through PGE's Annual Power Cost Update (Schedule 125) and Power Cost Adjustment Mechanism (PCAM) (Schedule 126). The PCAM is subject to the dead bands and sharing percentages as specified by Commission Order Nos. 07-015 and 10-478.

- Rate Spread/Design – Per Commission Order No. 11-517, tariff Schedule 135 will allocate the costs of the ADR on the basis of an equal percent of forecast generation revenues.

- Three Percent Test (ORS 757.259(6)) – The three percent test measures the annual overall average effect on customer rates resulting from deferral amortizations. The three percent test limits (exceptions at ORS 757.259(7) and (8)) the aggregated deferral amortizations during a 12-month period to no more than three percent of the utility's gross revenues for the preceding year. Because PGE is an electric utility, ORS 757.259(8) allows the Commission to consider up to a six percent limit.

Current ADR Pilot Period (2017 - 2020):
In contrast to the first two stages of the ADR program, PGE's current pilots are administered directly by the Company to its customers, with support from a program implementer and a technology integrator/demand response management system (DRMS) provider.

PGE revised the ADR pilot, along with Schedule 77, to create two pilots towards meeting PGE's goals of greater than 27 MW of peak load reduction by 2021 across all nonresidential segments and products. The Non-Residential Direct Load Control (DLC) Pilot, Schedule 25, provides Commercial customers with a more easily deployed DLC program. The Non-Residential Pricing Pilot, Schedule 26, resembles Schedule 77 but offers customers a larger variety of offerings based upon the results of the Energy Partner evaluations conducted by Itron (provided previously under Docket No. UM 1514), market research from Hansa customer interviews, focus groups, and Navigant report.

Recommended Revisions and Reporting Requirements:
Staff recommends the utility continue to submit the following updates to Commission Staff:

- PGE must keep on file, and be ready to submit copies of, all contracts signed by participating customers;
- Each quarter PGE will submit to Staff an informational filing containing a spreadsheet of each participating customers nominated load and event performance. PGE may redact identifying information if necessary and file as confidential the unredacted filing.
- PGE will run their loss of load probability, Renewable Energy Capacity Planning (RECAP), model with demand response parameters.[1]
    - o Staff suspects that PGE may be overly conservative in the application of their de-rate factor when calculating program cost effectiveness and believes that such a conservative approach may be hindering PGE's willingness to invest in resources to bring about additional demand response program proposals. While clear direction on calculating demand response has not been given to PGE it is important that PGE, the Commission, and stakeholders continue to iterate until such time as the Commission has the capacity to comprehensively address demand response cost effectiveness.
- A final evaluation will be submitted in the second quarter of 2021, after the next three operating seasons and the planned end of the Pilots.

Conclusion

Staff reviewed PGE's application and supporting program work papers. In previous deferral applications, PGE has demonstrated a cost effectiveness score of 1.03 with the revised program structure now internal to the Company.[2] In addition, the requested $3.7M for 2020 appears consistent with the expected participation and costs of operating the program internal to PGE.

The rationale for this deferral is still valid, and the Company's application meets the requirements of ORS 757.259 and OAR 860-027-0300. For these reasons, Staff recommends PGE's application be approved.

[1] For a description of the methodology see UM 1708, PGE's Compliance to Order No. 15-203 (April 28, 2016): Navigant - A Proposed Cost-Effectiveness Approach for Demand Response.
[2] See UM 1514, PGE's Supplemental Application, Attachment C, Dated 9/21/2017.

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PROPOSED COMMISSION MOTION:

Approve Portland General Electric's application for reauthorization to defer, with interest, the incremental costs associated with the Automated Demand Response Pilot (ADR Pilot), be approved for the 12-month period beginning January 1, 2020.

PGE UM 1514 (9) PGE ADR Deferral

ITEM NO. CA11

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: December 15, 2020

REGULAR ____ CONSENT X EFFECTIVE DATE January 1, 2021

DATE: December 7, 2020

TO: Public Utility Commission

FROM: Mitchell Moore and Kacia Brockman

THROUGH: Bryan Conway, John Crider, and Matt Muldoon **SIGNED**

SUBJECT: PORTLAND GENERAL ELECTRIC:
(Docket No. UM 1514(10))
Application for reauthorization of deferral of incremental costs associated with Non-Residential Demand Response Pilots.

STAFF RECOMMENDATION:

Approve Portland General's (PGE or Company) application for reauthorization to defer, with interest, the incremental costs associated with the Automated Demand Response Pilot (ADR Pilot) for the 12-month period beginning January 1, 2021.

DISCUSSION:

Issue

Whether the Public Utility Commission of Oregon (OPUC or Commission) should approve PGE's request for reauthorization to defer, with interest, the incremental costs associated with the Automated Demand Response Pilot, for later recovery in rates.

Applicable Law

The deferral of incremental ADR costs and recovery through an automatic adjustment clause (Schedule 135) were initially authorized by Commission Order No. 11-182, as part of a two-year pilot program. PGE submitted its deferral application on December 20, 2018, pursuant to ORS 757.259 and OAR 860-027-0300. ORS 757.259 provides the Commission with authority to authorize the deferral of utility revenues and expenses for later Inclusion in rates. OAR 860-027-0300 is the Commission's rule governing the use of deferred accounting by energy and large telecommunications utilities. Previous approval of this deferral was most recently granted by Order No. 20-259.

Background
The deferral of incremental ADR costs and recovery through an automatic adjustment clause (Schedule 135) were initially authorized by Commission Order No. 11-182, as part of a two-year pilot program. The Commission has authorized PGE to defer these each year since 2011. PGE seeks reauthorization with this filing for the period January 1, 2021 through December 31, 2021. In order to align the deferral periods with the pilot tariff terms, PGE intends to file for a re-authorization for the 12-month period beginning June 1, 2021.

Description of Amounts
Amounts requested for deferral include administration, vendor and equipment costs related to the pilot, as well as incentive payments to program participants.

Reasons for Deferral
Pursuant to ORS 757.259(2)(e), PGE seeks to continue deferred accounting treatment for the incremental costs associated with the ADR pilot. The granting of this reauthorization application will minimize the frequency of rate changes and match appropriately the costs borne by, and benefits received by, customers.

Proposed Accounting
PGE proposes to record the deferred costs in FERC account 182.3 (Regulatory Assets), with the offsetting credit recorded to FERC account 131 (Cash).

Estimate of Amounts
PGE estimates the amounts to be deferred during the first five months of 2021 to be approximately $2.1 million. PGE will file another deferral re-authorization request with an effective date of June 1, 2021 to align the deferral period with the tariff term period.

Information Related to Future Amortization

- Earnings review – An earnings review does not apply to an automatic adjustment clause, pursuant to ORS 757.259(5). If the pilot program is deemed successful, PGE proposes to have costs of the ADR program flow through PGE's Annual Power Cost Update (Schedule 125) and Power Cost Adjustment Mechanism

(PCAM) (Schedule 126), and be subject to the earnings reviewed contained within the PCAM.

- Prudence Review – A prudence review should include a verification that deferred amounts are incremental, and verification of the accounting methodology used to determine the final amortization balance.

- Sharing – if the ADR is deemed successful, then the proposal is for subsequent costs to flow through PGE's Annual Power Cost Update (Schedule 125) and Power Cost Adjustment Mechanism (PCAM) (Schedule 126). The PCAM is subject to the dead bands and sharing percentages as specified by Commission Order Nos. 07-015 and 10-478.

- Rate Spread/Design – Per Commission Order No. 11-517, tariff Schedule 135 will allocate the costs of the ADR on the basis of an equal percent of forecast generation revenues.

- Three Percent Test (ORS 757.259(6)) – The three percent test measures the annual overall average effect on customer rates resulting from deferral amortizations. The three percent test limits (exceptions at ORS 757.259(7) and (8)) the aggregated deferral amortizations during a 12-month period to no more than three percent of the utility's gross revenues for the preceding year. Because PGE is an electric utility, ORS 757.259(8) allows the Commission to consider up to a six percent limit.

Current ADR Pilot Period (2017 - 2021)
In contrast to the first two stages of the ADR program, PGE’s current pilots are administered directly by the Company to its customers, with support from a program implementer and a technology integrator/demand response management system (DRMS) provider.

PGE revised the ADR pilot to create two pilots towards meeting PGE's nonresidential demand response goals of greater than 27 MW of peak load reduction by 2021. The Non-Residential Direct Load Control (DLC) Pilot, Schedule 25, provides incentives to commercial customers that enroll DLC thermostats and participate in demand response events. The pilot began in 2019 and summer 2020 was the first event season with a statistically significant sample size, with 1,141 thermostats enrolled. The Non-Residential Pricing Pilot, Schedule 26, offers customers a range of incentives for curtailing load based on season, amount of advanced notification required, and number of event hours. There are 71 customers with 146 sites enrolled in this pilot. As of

October 2020, the pilots achieved 20.1 MW of summer peak load reduction and 15.4 MW of winter peak load reduction.

Recommended Revisions and Reporting Requirements
Staff recommends the utility continue to submit the following updates to Commission Staff:

- PGE must keep on file, and be ready to submit copies of, all contracts signed by participating customers;
- Each quarter PGE will submit to Staff an informational filing containing a spreadsheet of each participating customers nominated load and event performance. PGE may redact identifying information if necessary or file as confidential.

Conclusion

Staff reviewed PGE's application and supporting program work papers. In previous deferral applications, PGE has demonstrated a cost effectiveness score of 1.03 with the revised program structure now internal to the Company.[1] In addition, the requested $2.1M for the first half of 2021 appears consistent with the expected participation and costs of operating the program internal to PGE.

The rationale for this deferral is still valid, and the Company's application meets the requirements of ORS 757.259 and OAR 860-027-0300. For these reasons, Staff recommends PGE's application be approved.

PROPOSED COMMISSION MOTION:

Approve Portland General Electric's application for reauthorization to defer, with interest, the incremental costs associated with the Automated Demand Response Pilot for the 12-month period beginning January 1, 2021.

[1] See UM 1514, PGE's Supplemental Application, Attachment C, Dated 9/21/2017.

ITEM NO. CA15

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: December 13, 2022

REGULAR ____ **CONSENT** __X__ **EFFECTIVE DATE** __________N/A__________

DATE: December 5, 2022

TO: Public Utility Commission

FROM: Kathy Zarate

THROUGH: Bryan Conway, Marc Hellman, and Matt Muldoon **SIGNED**

SUBJECT: PORTLAND GENERAL ELECTRIC:
(Docket No. UM 1514 (12))
Requests for reauthorization to Deferral of Incremental Costs Associated with non-Residential Demand Response Pilots.

STAFF RECOMMENDATION:

Staff recommends the Commission approve Portland General Electric Company's (PGE or Company) application for reauthorization to defer, with interest, the incremental costs associated with its non-residential Direct Load Control (DLC) pilot for the 12-month period beginning June 1, 2022.

DISCUSSION:

Issue

Whether the Commission should approve PGE's request for reauthorization to defer, with interest, the incremental costs associated with its non-residential Direct Load Control pilot for later recovery in rates.

Applicable Law

ORS 757.259 provides the Commission with authority to authorize the deferral of utility revenues and expenses for later inclusion in rates. OAR 860-027-0300 are the Commission's rule governing the use of deferred accounting by energy and large telecommunications utilities.

Previous approval of this deferral was most recently granted by Order No. 21-421.

Analysis

Background
Schedule 25, PGE's non-residential direct load control pilot ("Non-Res DLC Pilot"), became effective December 1, 2017, as a complement to Schedule 26, the nonresidential demand response pilot. The Schedule 25 pilot is known to customers as the Energy Partner Smart Thermostat (EPST) Pilot. The EPST Pilot (aka Non-Res DLC Pilot) provides participants smart thermostats and installation, at a highly reduced cost. The Pilot also provides a seasonal per-participating-thermostat incentive to allow PGE to adjust the temperature setpoint of thermostats, curtailing load from electric HVAC systems during demand response events.

On January 26, 2022, the Commission issued Order No. 22-023 regarding PGE's request to approve its Flexible Load Multi-Year Plan. Pursuant to Order No. 22-023, the budget for PGE's Non-Res DLC Pilot was not approved. Instead, the Order adopted Staff's recommendation to wait to take action regarding the Pilot until PGE provided a detailed pilot proposal and justification to extend the program when requesting deferral reauthorization and a tariff revision.

On April 15, 2022, PGE filed Advice No. 22-07 to revise its Non-Res DLC Pilot. The Commission approved the advice filing on May 31, 2022.

In this filing, PGE seeks reauthorization to defer incremental costs associated with the Non-Res DLC Pilot for the period beginning June 1, 2022, through May 31, 2023.

Current Program
PGE proposes to continue the Non-Res DLC Pilot. On May 31, 2022, the Commission approved Advice No. 22-07 (revisions to PGE's Schedule 25) extending the Pilot through May 31, 2025. The Pilot will continue to be administered directly by PGE to its customers, with support from third-party vendors. PGE took this approach primarily to manage the customer's experience while providing PGE the flexibility to offer a variety of products and potentially adjust those products in the future.

Over the last deferral period (June 1, 2021 to May 31, 2022), PGE has connected 427 new thermostats, bringing the cumulative program total to 2,216 thermostats. Through April 30, 2022, program participants have accomplished energy curtailment nominations of up to 1.26 MW in the summer season and 1.17 MW in the winter season. PGE made the strategic decision to slow pilot growth throughout the last deferral period to build a foundation for future program stability, cost effective growth, and reliable measurement of demand response capacity values during direct load control events.

In addition, PGE addresses the UM 1514 Evaluations of PGE's Schedule 25 Energy Partner Direct Load Control Pilot for the Summer 2021 and Winter 2021/2022 Seasons. The evaluation provides pilot impact estimates and process recommendations for Summer 2021 and Winter 2021/22. This memo summarizes Schedule 25 evaluation outcomes from Summer 2021 and Winter 2021/22 and provides a summary of next steps for pilot evaluation. Staff reviewed the evaluation submitted by PGE on October 11, 2022, and did not find anything of concern.

Description of Amounts
PGE seeks renewal of deferred accounting treatment for the incremental costs associated with its Non-Res DLC Pilot.

Reasons for Deferral
Pursuant to ORS 757.259(2)(e), for the reasons discussed above, PGE seeks to continue deferred accounting treatment for the incremental costs associated with the Non-Res DLC Pilot. The granting of this reauthorization application will minimize the frequency of rate changes and match appropriately the costs borne by and benefits received by customers.

Proposed Accounting
PGE proposes to record the deferral as a regulatory asset in FERC Account 182.3 (Other Regulatory Assets) and credit the appropriate FERC expense accounts. When specific identification of the particular source of the regulatory asset cannot be reasonably made, then FERC Account 407.4 (Regulatory Credits) will be credited. In the absence of a deferred accounting order, the costs would be debited to the appropriate cost accounts.

Estimate of Amounts
PGE estimates the amount to be deferred during the reauthorization period to be approximately $1.3 million.

Information Related to Future Amortization

- Earnings review – Schedule 135 does not include an earnings review prior to amortization of the deferred costs of the Non-Res DLC Pilot.
- Prudence Review – A prudence review should include a verification that deferred amounts are incremental, and verification of the accounting methodology used to determine the final amortization balance.

- Sharing – There is no sharing mechanism with this deferral.
- Rate Spread/Design – Per Commission Order No. 11-517, tariff Schedule 135 will allocate the costs of the pilots on the basis of an equal percent of forecasted generation revenues.
- Three Percent Test (ORS 757.259(6)) – The amortization of the Pilot's deferred costs will be subject to the three percent test in accordance with ORS 757.259(6) and (8), which limits aggregated deferral amortizations during a twelve-month period to no more than three percent of the utility's gross revenues for the preceding year.

Conclusion

Staff reviewed PGE's application and supporting program work papers. Reauthorization of this deferral supports continuation of the non-residential DLC pilot as approved by the Commission in May 2022.

The rationale for this deferral is still valid, and the Company's application meets the requirements of ORS 757.259 and OAR 860-027-0300. For these reasons, Staff recommends PGE's application be approved.

The Company has reviewed this memo and agrees with Staff's recommendation.

PROPOSED COMMISSION MOTION:

Approve PGE's application for reauthorization to defer, with interest, the incremental costs associated with the non-residential Direct Load Control pilot for the 12-month period beginning June 1, 2022.

ITEM NO. CA 7

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: March 21, 2017

REGULAR ____ **CONSENT** __X__ **EFFECTIVE DATE** __January 1, 2017__

DATE: February 28, 2017

TO: Public Utility Commission

FROM: Mitchell Moore mpm

THROUGH: Jason Eisdorfer and Marc Hellman

SUBJECT: PORTLAND GENERAL ELECTRIC: (Docket No. UM 1514(6)) Requests reauthorization to defer the incremental costs associated with Automated Demand Response.

STAFF RECOMMENDATION:

I recommend that Portland General Electric's (PGE or Company) application for reauthorization to defer, with interest, the incremental costs associated with the Automated Demand Response Pilot (ADR Pilot), be approved for the 12-month period beginning January 1, 2017.

DISCUSSION:

Issue

Whether the Commission should approve PGE's request for reauthorization to defer, with interest, the incremental costs associated with the Automated Demand Response Pilot, for later recovery in rates.

Applicable Rule or Law

PGE submitted its deferral application on December 15, 2016, pursuant to ORS 757.259 and OAR 860-027-0300. ORS 757.259 provides the Commission with authority to authorize the deferral of utility revenues and expenses for later inclusion in rates. OAR 860-027-0300 are the Commission's rule governing the use of deferred accounting by energy and large telecommunications utilities. Previous approval of this deferral was most recently granted by Order No. 16-111.

Analysis

Background
The deferral of incremental ADR costs and recovery through an automatic adjustment clause (Schedule 135) were initially authorized by Commission Order No. 11-182, as part of a two-year pilot program. The Commission has authorized PGE to defer the incremental ADR costs each year since 2011.

PGE seeks reauthorization to defer incremental costs associated with the ADR Program and the new Pilot timeline for the period January 1, 2017, through December 31, 2017.

First ADR Pilot Period
PGE selected a third-party provider based on a combination of good credit, bidding summer and winter events, better technology, and a stronger marketing plan. The provider began its program marketing on September 1, 2011, but failed to meet the initial capacity milestone of 5 MW for the first winter season. The provider then began to experience financial difficulties and failed to meet additional terms of its agreement for the ADR pilot. On April 30, 2012, PGE terminated its contract with the provider.

New Proposed ADR Pilot Period
As discussed in PGE's report submitted with the second ADR evaluation on April 28, 2016, the pilot in its current form has fallen short of its nomination goal of 25 MW, with 11 MW expected to be nominated for the winter of 2016-2017. Additionally, PGE's contract with EnerNOC, the program's third-party provider, expires at the end of this year. These two factors have led both PGE and EnerNOC to explore adjustments to the program that may lead to greater success. While PGE and EnerNOC have not decided on the exact changes to take place, they expect that changes will include expanding offerings to medium-sized customers, flexibility in nomination windows, and potentially reaching out to other vendors to supplement EnerNOC. Because the ADR pilot continues to be in transition, PGE proposes to continue its deferred accounting and not move it into power costs as a capacity resource until it stabilizes as a program.

Description of Amounts
Pursuant to ORS 757.259(2)(e), PGE seeks renewal of deferred accounting treatment for the incremental costs associated with the ADR pilot. The approval of the Application will also enable the continued use of an automatic adjustment clause rate schedule which will provide for recovery of the incremental costs associated with the ADR through tariff Schedule 135.

Reasons for Deferral
Pursuant to ORS 757.259(2)(e), PGE seeks to continue deferred accounting treatment for the incremental costs associated with the ADR (initially authorized by the Commission through Order No. 11-182 on June 1, 2011). The granting of this reauthorization application will minimize the frequency of rate changes and match appropriately the costs borne by, and benefits received by, customers.

Proposed Accounting
PGE proposes to record the deferred costs in FERC account 182.3 (Regulatory Assets), with the offsetting credit recorded to FERC account 131 (Cash).

Estimate of Amounts
PGE estimates the amounts to be deferred in 2017 to be approximately $1.4 million.

Information Related to Future Amortization

- Earnings review – An earnings review does not apply to an automatic adjustment clause, pursuant to ORS 757.259(5). If the pilot program is deemed successful, PGE proposes to have costs of the ADR program flow through PGE's Annual Power Cost Update (Schedule 125) and Power Cost Adjustment Mechanism (PCAM) (Schedule 126) for the year 2018, and be subject to the earnings review contained within the PCAM.

- Prudence Review – A prudence review should include a verification that deferred amounts are incremental, and verification of the accounting methodology used to determine the final amortization balance.

- Sharing – If the ADR is deemed successful, then the proposal is for subsequent costs to flow through PGE's Annual Power Cost Update (Schedule 125) and Power Cost Adjustment Mechanism (PCAM) (Schedule 126). The PCAM is subject to the dead bands and sharing percent's as specified by Commission Order Nos. 07-015 and 10-478.

- Rate Spread/Design – Per Commission Order No. 11-517, tariff Schedule 135 will allocate the costs of the ADR on the basis of an equal percent of forecast generation revenues.

- Three Percent Test (ORS 757.259(6)) – The three percent test measures the annual overall average effect on customer rates resulting from deferral amortizations. The three percent test limits (exceptions at ORS 757.259(7) and (8)) the aggregated deferral amortizations during a 12-month period to no more than three percent of the utility's gross revenues for the preceding year. Because PGE is an electric utility, ORS 757.259(8) allows the Commission to consider up to a six percent limit.

Conclusion

The rationale for this deferral is still valid, and the Company's application meets the requirements of ORS 757.259 and OAR 860-027-0300. For these reasons, Staff recommends PGE's application be approved.

PROPOSED COMMISSION MOTION:

Approve PGE's application for reauthorization to defer the incremental costs associated with the Automated Demand Response Pilot (ADR Pilot), for the 12-month period beginning January 1, 2017.

PGE 1514(6) ADR Program deferral

ITEM NO. CA9

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: November 16, 2021

REGULAR ____ **CONSENT** __X__ **EFFECTIVE DATE** ______June 1, 2021______

DATE: November 8, 2021

TO: Public Utility Commission

FROM: Mitchell Moore and Kacia Brockman

THROUGH: Bryan Conway, John Crider, and Matt Muldoon **SIGNED**

SUBJECT: PORTLAND GENERAL ELECTRIC:
(Docket No. UM 1514(11))
Application for Reauthorization of Deferral of Incremental Costs
Associated with Non-Residential Demand Response Pilots.

STAFF RECOMMENDATION:

Approve Portland General's (PGE or Company) application for reauthorization to defer, with interest, the incremental costs associated with the non-residential Demand Response (DR) pilot, and the non-residential Direct Load Control (DLC) pilot for the 12-month period beginning June 1, 2021.

Approve PGE's request to modify its program evaluation for the DR and DLC pilots: 1) to submit the evaluations in Q3 of 2021, instead of Q2 in 2021, and; 2) to provide two comprehensive evaluations for each pilot, instead of a single evaluation combining both pilots.

DISCUSSION:

Issue

Whether the Public Utility Commission of Oregon (OPUC or Commission) should approve PGE's request for reauthorization to defer, with interest, the incremental costs associated with its non-residential Demand Response and Direct Load Control pilots, (collectively referred to as "Energy Partner") for later recovery in rates.

Applicable Law

The deferral of incremental Energy Partner costs and recovery through an automatic adjustment clause (Schedule 135) were initially authorized by Commission Order No. 11-182, as part of a two-year pilot program. PGE submitted its deferral application on December 20, 2018, pursuant to ORS 757.259 and OAR 860-027-0300. ORS 757.259 provides the Commission with authority to authorize the deferral of utility revenues and expenses for later Inclusion in rates. OAR 860-027-0300 are the Commission's rule governing the use of deferred accounting by energy and large telecommunications utilities. Previous approval of this deferral was most recently granted by Order No. 20-479.

Analysis

Background
The deferral of incremental Energy Partner costs and recovery through an automatic adjustment clause (Schedule 135) were initially authorized by Commission Order No. 11-182, as part of a two-year pilot program. The Commission has authorized PGE to defer these each year since 2011. In order to align the deferral periods with the pilot tariff terms, PGE seeks to modify this reauthorization for the period June 1, 2021 through May 31, 2022. (The previous deferral authorization period was January 1, 2021 through December 31, 2021.)

The non-residential DLC pilot is defined by Schedule 26. The program provides nonresidential customers with a turnkey, direct load control program. The pilot offers incentives to allow PGE to control up to 3,800 qualified thermostats during direct load control events, while enabling the customer to override the control. Through April 30, 2021 PGE has enrolled 1,710 thermostats and curtailment nominations of 1.06 MW of energy in the summer and 0.81 MW of energy in the winter season.

The non-residential DR pilot provides a variety of participation levels in DR events, allowing customers to select availability periods, notification times, and maximum event hours, and whether to participate in winter or summer or both seasons. PGE reports as of April 30, 2021 DR customer nominations of 20.77 MW of energy in the summer season, and 14.6 MW of energy in the winter season.

PGE plans to begin reporting on an evaluating the two Energy Partner pilot elements independently beginning in 2022. On November 3, 2021, PGE filed its Flexible Load Multi-Year Plan in Docket No. UM 2141. The Multi-Year Plan includes a proposal to transition the non-residential DR pilot to an ongoing program. PGE plans to file an update to Schedule 26 in 2022 to reflect the ongoing program offerings. The Multi-Year

Plan also describes PGE's plan to continue the non-residential DLC pilot as a stand-alone pilot with new goals that are informed by a market potential study performed in the summer of 2021. PGE is also developing a new delivery strategy based on an internal pilot review, as reported to Staff at the Q3 2021 Demand Response Advisory Group meeting.

PGE proposes a new cost recovery mechanism in its Multi-Year Plan that would incorporate all of its demand response programs into a single recovery mechanism. If approved by the Commission, that new mechanism may replace this deferral authorization.

Pilot Evaluation
On June 11, 2021, PGE filed a request to extend the timeframe for the Energy Partners pilot evaluation from Q2 to Q3 2021, and to evaluate the non-residential DR (Schedule 26) and non-residential DLC (Schedule 25) pilots separately instead of jointly. In conversations with PGE, Staff expressed support for PGE's proposed evaluation strategy and timeline. Accordingly, PGE conducted an evaluation of the non-residential DR pilot to determine the pilot's readiness to transition to an ongoing program and filed it in on September 30, 2021. Staff appreciates that PGE used Staff's Pilot-to-Program guidance as a basis for that evaluation. The non-residential DLC pilot is still nascent and being redesigned by PGE. The DLC pilot will be evaluated as a standalone pilot in the future after PGE has established the pilot's new goals and learning objectives and gained operational experience with the pilot.

Description of Amounts
Amounts requested for deferral include administration, vendor and equipment costs related to the pilot, as well as incentive payments to program participants.

Reasons for Deferral
Pursuant to ORS 757.259(2)(e), PGE seeks to continue deferred accounting treatment for the incremental costs associated with the Energy Partner pilots. The granting of this reauthorization application will minimize the frequency of rate changes and match appropriately the costs borne by, and benefits received by, customers.

Proposed Accounting
PGE proposes to record the deferred costs in FERC account 182.3 (Regulatory Assets), with the offsetting credit recorded to FERC account 131 (Cash).

Estimate of Amounts
PGE estimates the amount to be deferred during the reauthorization period to be approximately $4.2 million.

Information Related to Future Amortization

- Earnings review - An earnings review does not apply to an automatic adjustment clause, pursuant to ORS 757.259(5).
- Prudence Review - A prudence review should include a verification that deferred amounts are incremental, and verification of the accounting methodology used to determine the final amortization balance.
- Sharing – There is no sharing mechanism with this deferral, however if the Energy Partner programs are deemed successful, then the proposal is for subsequent costs to flow through PGE's Annual Power Cost Update (Schedule 125) and Power Cost Adjustment Mechanism (PCAM) (Schedule 126). The PCAM is subject to the dead bands and sharing percentages as specified by Commission Order Nos. 07-015 and 10-478.
- Rate Spread/Design - Per Commission Order No. 11-517, tariff Schedule 135 will allocate the costs of the pilots on the basis of an equal percent of forecast generation revenues.
- Three Percent Test (ORS 757.259(6)) - The three percent test measures the annual overall average effect on customer rates resulting from deferral amortizations. The three percent test limits (exceptions at ORS 757.259(7) and (8)) the aggregated deferral amortizations during a 12-month period to no more than three percent of the utility's gross revenues for the preceding year. Because PGE is an electric utility, ORS 757.259(8) allows the Commission to consider up to a six percent limit.

Conclusion

Staff reviewed PGE’s application and supporting program work papers. Reauthorization of this deferral allows for the transition of the successful non-residential DR pilot to an ongoing program offering, and for the redesign of the non-residential DLC pilot into a standalone pilot with its own goals and learning objectives.

The rationale for this deferral is still valid, and the Company's application meets the requirements of ORS 757.259 and OAR 860-027-0300. For these reasons, Staff recommends PGE's application be approved.

PROPOSED COMMISSION MOTION:

Approve PGE's application for reauthorization to defer, with interest, the incremental costs associated with the non-residential Demand Response pilot, and the non-residential Direct Load Control pilot for the 12-month period beginning June 1, 2021.

Approve PGE's request to modify its program evaluation for the DR and DLC pilots: 1) to submit the evaluations in Q3 of 2021, instead of Q2 in 2021, and; 2) to provide two comprehensive evaluations for each pilot, instead of a single evaluation combining both pilots.

PGE UM 1514 11 Non Res DR Pilot Deferral

ITEM NO. CA14

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: June 19, 2018

REGULAR ____ **CONSENT** X **EFFECTIVE DATE** **April 18, 2018**

DATE: June 12, 2018

TO: Public Utility Commission

FROM: Mitchell Moore MPn

THROUGH: Jason Eisdorfer, and John Crider JCfor JE JC

SUBJECT: PORTLAND GENERAL ELECTRIC: (Docket No. UM 1827(1)) Requests reauthorization to defer costs associated with the PGE Demand Response Water Heater Pilot.

STAFF RECOMMENDATION:

Staff recommends the Commission approve Portland General Electric Company's (PGE or Company) request for reauthorization to defer costs associated with its Demand Response Water Heater Pilot for the 12-month period beginning April 18, 2018.

DISCUSSION:

Issue

Whether the Commission should grant PGE's request, reauthorizing deferral, for later ratemaking treatment, of the costs associated with its Demand Response Water Heater pilot program.

Applicable Law

757.259 provides the Commission with authority to authorize the deferral of utility revenues and expenses for later inclusion in rates. Specific amounts eligible for deferred accounting treatment with interest authorized by the Commission include:

> Identifiable utility expenses or revenues, the recovery or refund of which the commission finds should be deferred in order to minimize the frequency of rate changes or the fluctuation of rate levels or to match appropriately the costs borne by and benefits received by ratepayers.

ORS 757.259(2)(e).

OAR 860-027-0300 is the Commission's rule governing the use of deferred accounting by energy and large telecommunications utilities. In OAR 860-027-0300(3) the Commission has set forth the requirements for the contents of deferred accounting applications. Applications for reauthorization must include that information along with a description and explanation of the entries in the deferred account to the date of the application for reauthorization and the reason for continuation of deferred accounting. OAR 860-027-0300(4). Notice of the application must be provided pursuant to OAR 860-027-0300(6).

In Order No. 05-1070, Docket No. UM 1147, the Commission determined that interest may accrue interest on deferred accounts at the authorized rate of return until amortization. Subsequent orders in Docket No. UM 1147 establish the rate during amortization. See Order Nos. 08-263, 10-279.

Analysis

Background

On June 28, 2017, with Order No. 17-224, the Commission approved the original deferral filing for PGE's Demand Response Water Heater Pilot. That order provided that the automatic adjustment clause found in PGE's Schedule 135 entails deferring the incremental costs incurred for a Demand Response Water Heater Pilot for the summer of 2017 through 2019. As such, costs associated with the deferral are amortlzed through PGE's Schedule 135, Demand Response Cost Recovery Mechanism.

The purpose of the program is to retrofit existing water heaters in multifamily residences (MFRs) with demand response technology in order to help inform an effective design for a water heater demand response program, quantify energy consumption that can be shifted to different times, determine appropriate incentive levels for customers, integrate and test different technologies, and implement different demand response dispatch strategies.

PGE's 2016 Integrated Resource Plan (IRP) discussed various types of demand response, including those that utilize smart water heaters. Smart water heaters (installed with digital controls and the ability to readily attach communications equipment) are an important demand resource for PGE and present a wide array of use cases such as load shedding, load shifting and providing ancillary services.

The program targets MFR housing because of its high concentration of electric water heaters. The pilot, in addition to installing demand response-enabled technology on existing water heaters, also provides a monetary incentive to MFR property managers to replace aging water heaters with demand response capable water heaters (i.e., smart water heaters).

MFR demand response water heaters address a hard-to-reach segment of the residential market where few demand response technologies are currently feasible. Water heater demand response also supports PGE's mid-term demand-side management initiatives by allowing the researching of synergies between water heater demand response and smart thermostat programs. Further, water heaters represent a distributed resource, which supports PGE's long-term smart grid initiatives, as each water heater can be controlled to meet specific demand response needs. Finally, water heater demand response is a more flexible resource compared to other forms of demand response because it requires no notification, is a year-round resource, and has minimal customer comfort impact.

As of this filing, PGE has selected both a vendor for implementation and a Demand Response Management System (DRMS) vendor. PGE is currently in the process of testing integration between the water heater retrofit switch and the DRMS, and expects that it would be able to control water heaters with the switch as of the end of May 2018.

Description of Expense
Expenses for this deferral include: the cost of implementing the communication interface; managing defaults or repairs; and managing new participant enrollment; software licensing; data plan subscription; and PGE marketing.

Reason for Deferral
The use of deferred accounting for this pilot will minimize the frequency of rate changes and match appropriately the costs borne by and benefits received by customers.

Proposed Accounting
PGE proposes to record the deferred amount as a regulatory asset in FERC account 182.3, Other Regulatory Assets, with a credit to FERC account 456, Other Revenue.

PGE UM 1827(1)
June 12, 2018
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Estimate of Amounts
PGE estimates the incremental costs of the pilot will be approximately $5.1 million through the end of 2019, as illustrated in the following table:

Year	2017 Actual	2018	2019	Total
Pilot Cost	$65,273	$2,051,000	$3,011,277	$5,127,500

Information Related to Future Amortization

- Earnings review – An earnings review is generally required prior to amortization of deferrals, pursuant to ORS 757.259(5). However, because this is associated with the Schedule 135 automatic adjustment clause, an earnings review will not be performed.

- Prudence Review – A prudence review is required prior to amortization and should include the verification of the accounting methodology used to determine the final amortization balance. In addition, PGE will submit a pilot evaluation report that will provide detailed cost summaries, estimated kW shifting and the result of customer surveys.

- Sharing – There is no sharing under the filed mechanisms.

- Rate Spread/Design – The demand response pilot amortizations will be spread as specified in Schedule 135.

- Three Percent Test (ORS 757.259(6)) – The three percent test measures the annual overall average effect on customer rates resulting from deferral amortizations. The three percent test limits (exceptions at ORS 757.259(7) and (8)) the aggregated deferral amortizations during a 12-month period to no more than three percent of the utility's gross revenues for the preceding year. Because PGE is an electric utility, ORS 757.259(8) allows the Commission to consider up to a six percent limit. The limit for these deferrals will be determined at the time of amortization.

Conclusion

The proposed multifamily residential demand response pilot is a cost effective investment in a necessary demand side resource and associated long term communication infrastructure. The program is expected to produce net benefits to ratepayers while advancing PGE's demand response capabilities. Staff recommends approval of the request for reauthorization of incremental program costs.

PROPOSED COMMISSION MOTION:

Approve PGE's application for reauthorization to defer the costs associated with the Demand Response Water pilot program, for the 12-month period beginning April 18, 2018.

PGE UM 1827(1) – DR Water Heater pilot

ITEM NO. CA13

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: December 15, 2020

REGULAR ____ CONSENT ____ EFFECTIVE DATE April 18, 2020

DATE: December 7, 2020

TO: Public Utility Commission

FROM: Mitchell Moore and Kacia Brockman

THROUGH: Bryan Conway, John Crider, and Matt Muldoon **SIGNED**

SUBJECT: PORTLAND GENERAL ELECTRIC:
(Docket No. UM 1827(3))
Requests reauthorization to defer costs associated with the PGE Demand Response Water Heater Pilot.

STAFF RECOMMENDATION:

Approve Portland General Electric's (PGE or Company) request for reauthorization to defer costs associated with its Demand Response Water Heater Pilot for the 12-month period beginning April 18, 2020.

DISCUSSION:

Issue

Whether the Public Utility Commission of Oregon (Commission) should reauthorize PGE's request to defer for later ratemaking treatment the costs associated with its Demand Response Water Heater pilot program.

Applicable Law

PGE submitted its deferral application on April 15, 2020, pursuant to ORS 757.259 and OAR 860-027-0300. ORS 757.259 provides the Commission with authority to authorize the deferral of utility revenues and expenses for later inclusion in rates.
OAR 860-027-0300 is the Commission's rule governing the use of deferred accounting by energy and large telecommunications utilities.

PGE Docket No. UM 1827(3)
December 7, 2020
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Analysis

Background

On June 28, 2017, the Commission approved the original deferral filing for PGE's Demand Response Water Heater Pilot. The purpose of the program is to retrofit existing water heaters in multifamily residences (MFRs) with demand response technology in order to help inform an effective design for a water heater demand response program, quantify energy consumption that can be shifted to different times, determine appropriate incentive levels for customers, integrate and test different technologies, and implement different demand response dispatch strategies.

PGE's 2016 and 2019 Integrated Resource Plans (IRPs) find smart water heaters (installed with digital controls and the ability to readily attach communications equipment) are an important demand resource for PGE and present a wide array of use cases such as load shedding, load shifting and providing ancillary services.

The program targets MFR housing because of its high concentration of electric water heaters. The pilot, in addition to installing demand response-enabled technology on existing water heaters, also provides a monetary incentive to MFR property managers to replace aging water heaters with demand response capable water heaters (i.e., smart water heaters).

MFR demand response water heaters address a hard-to-reach segment of the residential market where few demand response technologies are currently feasible. Water heater demand response also supports PGE's mid-term demand-side management (DSM) initiatives by allowing the researching of synergies between water heater demand response and smart thermostat programs. Further, water heaters represent a distributed resource, which supports PGE's long-term smart grid initiatives, as each water heater can be controlled to meet specific demand response needs. Finally, water heater demand response is a more flexible resource compared to other forms of demand response because it requires no notification, is a year-round resource, and has minimal customer comfort impact.

In 2018, PGE selected both a vendor for implementation and a Demand Response Management System (DRMS) vendor. Since May 2018, PGE has been successfully testing integration between the water heater retrofit switch and the DRMS.

PGE states in its filing that the pilot is on track and approximately 8,300 water heater retrofit switches have been installed in 74 distinct properties as of the end of March 2020. PGE expects to have installed a total of 10,000 retrofit-switched by end of January 2021.

PGE Docket No. UM 1827(3)
December 7, 2020
Page 3

PGE met with Staff twice in November 2020 to discuss future plans for the pilot in 2021. Those plans will be detailed in the Company's upcoming request to extend the pilot beyond its current term date of January 31, 2021.

Description of Expense
Expenses for this deferral include: the cost of implementing the communication interface, managing defaults or repairs, managing new participant enrollment, software licensing, data plan subscription, and PGE marketing.

Reason for Deferral
The use of deferred accounting for this pilot will minimize the frequency of rate changes and match appropriately the costs borne by and benefits received by customers.

Proposed Accounting
PGE proposes to record the deferred amount as a regulatory asset in FERC account 182.3, Other Regulatory Assets, with a credit to FERC account 456, Other Revenue.

Estimate of Amounts
PGE estimates the incremental costs of the pilot will be approximately $3.5 million through the end of 2019, as illustrated in the following table:

Year	**2018 Actual**	**2019 Actual**	**2020 Forecast**	**2021 Forecast**	**Total**
Pilot Cost	$1,592,378	$2,999,211	$3,556,223	$4,149,283	$11,838,923

Information Related to Future Amortization

- Earnings review – An earnings review is generally required prior to amortization of deferrals, pursuant to ORS 757.259(5). However, because this is associated with the Schedule 135 automatic adjustment clause, an earnings review will not be performed.

- Prudence Review – A prudence review is required prior to amortization and should include the verification of the accounting methodology used to determine the final amortization balance. In addition, PGE will submit a pilot evaluation report that will provide detailed cost summaries, estimated kW shifting and the result of customer surveys.

- Sharing – There is no sharing under the filed mechanisms.

- Rate Spread/Design – The demand response pilot amortizations will be spread as specified in Schedule 135.

- Three Percent Test (ORS 757.259(6)) – The three percent test measures the annual overall average effect on customer rates resulting from deferral amortizations. The three percent test limits (exceptions at ORS 757.259(7) and (8)) the aggregated deferral amortizations during a 12-month period to no more than three percent of the utility's gross revenues for the preceding year. Because PGE is an electric utility, ORS 757.259(8) allows the Commission to consider up to a six percent limit. The limit for these deferrals will be determined at the time of amortization.

Conclusion

The proposed multifamily residential demand response pilot is a cost effective investment in a necessary demand side resource and associated long-term communication infrastructure. The program is expected to produce net benefits to ratepayers while advancing PGE's demand response capabilities. Staff recommends approval of the request for reauthorization of incremental program costs.

PROPOSED COMMISSION MOTION:

Approve PGE's application to defer the costs associated with the Demand Response Water pilot program, for the 12-month period beginning April 18, 2020.

ITEM NO. CA4

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: July 13, 2021

REGULAR ____ CONSENT ____ EFFECTIVE DATE ______ April 18, 2021 ______

DATE: July 5, 2021

TO: Public Utility Commission

FROM: Mitchell Moore and Kacia Brockman

THROUGH: Bryan Conway, John Crider, and Matt Muldoon **SIGNED**

SUBJECT: PORTLAND GENERAL ELECTRIC:
(Docket No. UM 1827(4))
Requests reauthorization to defer costs associated with the PGE Demand Response Water Heater Pilot.

STAFF RECOMMENDATION:

Staff recommends the Commission approve Portland General Electric's (PGE, or Company) request for reauthorization to defer costs associated with its Demand Response Water Heater Pilot for the 12-month period beginning April 18, 2021.

DISCUSSION:

Issue

Whether the Commission should reauthorize PGE's request to defer for later ratemaking treatment the costs associated with its Demand Response Water Heater pilot program.

Applicable Law

PGE submitted its deferral application on April 12, 2021, pursuant to ORS 757.259 and OAR 860-027-0300. ORS 757.259 provides the Commission with authority to authorize the deferral of utility revenues and expenses for later inclusion in rates. OAR 860-027-0300 is the Commission's rule governing the use of deferred accounting by energy and large telecommunications utilities.

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July 5, 2021
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Analysis

Background

On June 28, 2017, the Commission approved the original deferral filing for PGE's Demand Response Water Heater Pilot. The purpose of the pilot is to retrofit existing water heaters in multifamily residences (MFRs) with demand response technology in order to help inform an effective design for a water heater demand response program, quantify energy consumption that can be shifted to different times, determine appropriate incentive levels for customers, integrate and test different technologies, and implement different demand response dispatch strategies.

PGE's 2016 Integrated Resource Plan (IRP) discussed various types of demand response, including those that utilize smart water heaters. Smart water heaters (installed with digital controls and the ability to readily attach communications equipment) are an important demand resource for PGE and present a wide array of use cases such as load shedding, load shifting and providing ancillary services.

The pilot targets MFR housing because of its high concentration of electric water heaters. The pilot, in addition to installing demand response-enabled technology on existing water heaters, also provides a monetary incentive to MFR property managers to replace aging water heaters with demand response capable water heaters (i.e., smart water heaters).

MFR demand response water heaters address a hard-to-reach segment of the residential market where few demand response technologies are currently feasible. Water heater demand response also supports PGE's mid-term demand-side management initiatives by allowing the researching of synergies between water heater demand response and smart thermostat programs. Further, water heaters represent a distributed resource, which supports PGE's long-term smart grid initiatives, as each water heater can be controlled to meet specific demand response needs. Finally, water heater demand response is a more flexible resource compared to other forms of demand response because it requires no notification, is a year-round resource, and has minimal customer comfort impact.

In 2018, PGE selected both a vendor for implementation and a Demand Response Management System (DRMS) vendor. Since May 2018, PGE has been successfully testing integration between the water heater retrofit switch and the DRMS.

PGE states in its filing that as of March 2021, the pilot has deployed 10,035 water heater retrofit switches across 29 property management companies representing 99 distinct sites. In addition to these 10,035, PGE has 16 contracted properties with approximately 925 switches scheduled to be installed by year-end 2021. The Pilot has two types of retrofit switches in the field, those connected via Wi-Fi and those connected via cellular signal. Evaluation data has identified that cell-enabled switches have a higher connectivity rate (94% season average) than Wi-Fi connected switches (89% season average). PGE intends to test a second cell-enabled switch vendor to verify connectivity rates.

PGE met with Staff twice in November 2020 to discuss plans for the pilot in 2021. In January 2021, the Commission approved a 30-month pilot extension, through July 31, 2023, and an expansion from 10,000 to 18,000 participating water heaters with an incremental budget of $4.96 million.[1] PGE will use the extension to try to achieve cost-effectiveness for the pilot by implementing strategies to lower the per-unit cost and increase the per-unit performance. The pilot's current cost-effectiveness is 0.82 using the Total Resource Cost method.

Description of Expense
Expenses for this deferral include: the cost of implementing the communication interface; managing defaults or repairs; and managing new participant enrollment; software licensing; data plan subscription; and PGE marketing.

Reason for Deferral
The use of deferred accounting for this pilot will minimize the frequency of rate changes and match appropriately the costs borne by and benefits received by customers.

Proposed Accounting
PGE proposes to record the deferred amount as a regulatory asset in FERC Account 182.3, Other Regulatory Assets, with a credit to FERC Account 456, Other Revenue.

Estimate of Amounts
PGE estimates the incremental costs of the pilot will be approximately $2.1 million through the end of 2021, as illustrated in the following table:[2]

Year	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	Total
Pilot Cost	$1,073,623	$2,028,199	$2,658,525	$2,057,455	$7,878,385

[1] See Docket No. ADV 1097, PGE Advice No. 20-46, approved by the Commission at the January 26, 2021 public meeting.
[2] 2019 and 2020 actuals shown here reflect PGE corrections in work papers accompanying this filing.

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July 5, 2021
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Information Related to Future Amortization

- Earnings review – An earnings review is generally required prior to amortization of deferrals, pursuant to ORS 757.259(5). However, because this is associated with the Schedule 135 automatic adjustment clause, an earnings review will not be performed.

- Prudence Review – A prudence review is required prior to amortization and should include the verification of the accounting methodology used to determine the final amortization balance. In addition, PGE will submit a pilot evaluation report in August of 2021 that will provide detailed cost summaries, estimated kW shifting and the result of customer surveys.

- Sharing – There is no sharing under the filed mechanisms.

- Rate Spread/Design – The demand response pilot amortizations will be spread as specified in Schedule 135.

- Three Percent Test (ORS 757.259(6)) – The three percent test measures the annual overall average effect on customer rates resulting from deferral amortizations. The three percent test limits (exceptions at ORS 757.259(7) and (8)) the aggregated deferral amortizations during a 12-month period to no more than three percent of the utility's gross revenues for the preceding year. Because PGE is an electric utility, ORS 757.259(8) allows the Commission to consider up to a six percent limit. The limit for these deferrals will be determined at the time of amortization.

<u>Conclusion</u>

The proposed multifamily residential demand response pilot is testing a path to cost-effectiveness for necessary demand side resource and associated communication infrastructure. The pilot is expected to produce benefits to ratepayers while advancing PGE's long term demand response capabilities. Staff recommends approval of the request for reauthorization of incremental program costs.

PROPOSED COMMISSION MOTION:

Approve PGE's request for reauthorization to defer costs associated with its Demand Response Water Heater Pilot for the 12-month period beginning April 18, 2021.

ITEM NO. CA8

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: June 27, 2017

REGULAR ____ **CONSENT** X **EFFECTIVE DATE** **June 28, 2017**

DATE: June 1, 2017

TO: Public Utility Commission

NM for JSK NM

FROM: Jason R. Salmi Klotz and Nolan Moser

JE JC

THROUGH: Jason Eisdorfer and John Crider

SUBJECT: PORTLAND GENERAL ELECTRIC: (Docket No. UM 1827) PGE's Application for Deferred Accounting of Costs Associated with the PGE Demand Response Water Heater Pilot and related Advice Filing No.17-09, New Schedule 4 Multifamily Residential Demand Response Water Heater Pilot Rider.

STAFF RECOMMENDATION:

Staff recommends that the Commission approve Portland General Electric Company's (PGE or Company) request for an approval of program cost deferral of $5.1 million through 2019 for the Company's new multifamily water heater demand response program (Phase 1). Further, Staff recommends that the Commission approve PGE's related Advice Filing No. 17-09, New Schedule 4 Multifamily Residential Demand Response Water Heater Pilot Rider.

DISCUSSION:

Issue

Whether to approve PGE's request to defer for later ratemaking treatment the costs associated with a new water heater demand response program for the 12-month period beginning April 18, 2017; and also whether to approve PGE's related Advice filing No. 17-09, New Schedule 4 Multifamily Water Heater Pilot Rider, with an effective date of July 1, 2017.

Applicable Rule or Law

PGE submitted its deferral application on April 18, 2017, pursuant to ORS 757.259 and OAR 860-027-0300. ORS 757.259 provides the Commission with authority to authorize the deferral of utility revenues and expenses for later inclusion in rates.
OAR 860-027-0300 is the Commission's rule governing the use of deferred accounting by energy and large telecommunications utilities.

ORS 757.210 concerns the use of an "automatic adjustment clause" (AAC) in a utility's rate schedule. If an ACC is permitted by the Commission, it provides for rate increases or decreases or both, without a prior hearing, reflecting, in relevant part, increases or decreases or both in incurred costs. An ACC is subject to Commission review at least once every two years.

Analysis

Background
In November 2016, PGE filed its proposed 2016 Integrated Resource Plan (IRP). The IRP is currently being processed in Docket No. LC 66. The IRP discussed various types of demand response programs, including those that utilize smart water heaters. Smart water heaters (installed with digital controls and the ability to readily attach communications equipment) are an important demand resource for PGE and present a wide array of use cases such as load shedding, load shifting and providing ancillary services.

The current proposal is for Phase 1 of the smart water heater program. The smart water heater program is different from a pilot in the respect that it is expected to continue to a Phase 2 roll-out. Thus, additional customers, capacity and capability are added to the smart water heater program as a growing demand response resource. Additionally, PGE has submitted through Advice No. 17-09 Schedule 4, a Multifamily Residential Demand Response Water Heater Phase 1 program. Customers participating in the program will remain on Schedule 7 while electing to participate in the Schedule 4 a Multifamily Residential Demand Response Water Heater Pilot Rider. Schedule 4 acts as a rider in conjunction with Schedule 7 thereby allowing participants to assent to terms of service while participating in the program. All other parts of service will remain as in Schedule 7.

The proposed program will target multifamily residential (MFR) housing because of its high concentration of electric water heaters. The pilot will: 1) retrofit existing water heaters with demand response enabled technology, and 2) provide a monetary incentive to MFR property managers to replace aging water heaters with demand response capable water heaters (i.e., smart water heaters).

MFR demand response water heaters address a hard-to-reach segment of the residential market where few demand response technologies are currently feasible. Water heater demand response also supports PGE's mid-term demand-side management initiatives by allowing the researching of synergies between water heater demand response and smart thermostat programs. Further, water heaters represent a distributed resource, which supports PGE's long-term smart grid initiatives, as each water heater can be controlled to meet specific demand response needs. Finally, water heater demand response is a more flexible resource compared to other forms of demand response because it requires no notification, is a year-round resource, and has minimal customer comfort impact.

PGE will provide incentives to MFR property managers and tenants for the costs of retrofitting existing water heaters with demand response technology and replacing aging water heaters with demand response capable water heaters. By installing communication interfaces to receive a demand response signal, PGE can signal the water heater and shift load at peak times. When established, PGE envisions that curtailment could shift up to 4 MW during peak load times during this pilot. No advance notification of load shifting events will need to be provided to customers, and there will be no limit to the number of direct load control events, similar to the structure of the recently approved PGE/BPA demand response water heater pilot.[1]

Description of Expense
PGE estimates that this pilot will achieve a net positive benefit based on a Total Resource Cost Test, which measures the net benefits of a program for all stakeholders involved. The primary benefit from this pilot is reduced need for capacity through reduced demand. PGE anticipates that each residential customer will be able to realize a 0.5 kW reduction in demand, and a 50 kWh reduction in energy annually.

PGE estimates that approximately 50 percent of costs from this pilot will consist of: implementing the communication interface; managing defaults or repairs; and managing new participant enrollment. PGE expects other costs from this pilot to include: software licensing; data plan subscription for communication; and PGE marketing.

Staff understand the roughly $2.5M communication interface costs will be more broadly applicable as a demand response management system or DRMS which can be utilized by subsequent PGE demand response programs. This communication infrastructure investment is made possible through this program because of cost effective nature of

[1] Docket No. ADV 507, Advice No. 17-02.

the current program structure. The investment in DRMS is in addition to PGE's Advanced Meter Infrastructure and Customer Information System. Staff has engaged in discussion subsequent to PGE's initial filing with PGE on the details of the DRMS investment. PGE has provided a supplemental filing in this docket outlining DRMS investment details. Staff supports PGE's request to make the DRMS investment.

Although additional to other communication infrastructure, the DRMS will enable a more flexible and responsive demand response resource build-out and utilization that would not otherwise be feasible. This includes capabilities to operate demand response assets unobtrusively, such that participants will likely not notice any change in their electric or hot water services. Additionally, investment in the DRMS will enable future demand response capabilities, such as ancillary services from disparate demand side, customer owned, distributed energy resources. The DRMS and the overall program structure is highly scalable and is anticipated to provide net benefits to customers. Staff believes that the investments made here are necessary to move PGE from the pilot phase to full demand response resource development.

The Company has requested authorization to defer for later ratemaking treatment costs associated with its demand response water heater pilot. The automatic adjustment clause found in PGE's Schedule 135 entails deferring the incremental costs incurred for a Demand Response Water Heater Pilot for the summer of 2017 through 2019. As such, costs associated with this deferral will be amortized through PGE's Schedule 135, Demand Response Cost Recovery Mechanism.

PGE has proposed tariff sheets associated with Tariff P.U.C. No. 18 with an effective date of July 1, 2017.

Reason for Deferral
The use of deferred accounting for this pilot will minimize the frequency of rate changes and match appropriately the costs borne by and benefits received by customers.

Proposed Accounting
PGE proposes to record the deferred amount as a regulatory asset in FERC account 182.3, Other Regulatory Assets, with a credit to FERC account 456, Other Revenue. In the absence of a deferred accounting order from the Commission, PGE state that it would not proceed with the pilot at this time.

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June 1, 2017
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Estimate of Amounts
PGE estimates the incremental costs of the pilot will be approximately $5.1 million through the end of 2019, as illustrated in the following table:

Year	2017	2018	2019	Total
Pilot Cost	$769,125	$1,794,625	$2,563,750	$5,127,500

Information Related to Future Amortization

- Earnings review – An earnings review is generally required prior to amortization of deferrals, pursuant to ORS 757.259(5). In accordance with ORS 757.259(5), because this is associated with the Schedule 135 automatic adjustment clause, an earnings review will not be performed.

- Prudence Review – A prudence review is required prior to amortization and should include the verification of the accounting methodology used to determine the final amortization balance. In addition, PGE will submit a pilot evaluation report that will provide detailed cost summaries, estimated kW shifting and the result of customer surveys.

- Sharing – There is no sharing under the filed mechanisms.

- Rate Spread/Design – The demand response pilot amortizations will be spread as specified in Schedule 135.

- Three Percent Test (ORS 757.259(6)) – The three percent test measures the annual overall average effect on customer rates resulting from deferral amortizations. The three percent test limits (exceptions at ORS 757.259(7) and (8)) the aggregated deferral amortizations during a 12-month period to no more than three percent of the utility's gross revenues for the preceding year. Because PGE is an electric utility, ORS 757.259(8) allows the Commission to consider up to a six percent limit. The limit for these deferrals will be determined at the time of amortization.

<u>Conclusion</u>

The proposed multifamily residential demand response pilot is a cost effective investment in a necessary demand side resource and associated long term communication infrastructure. The program is expected to produce net benefits to ratepayers while advancing PGE's demand response capabilities. Staff recommends approval of the request for program cost deferral and program development.

PROPOSED COMMISSION MOTION:

Approve PGE's application to defer the costs associated with the proposed demand response program, for the 12-month period beginning April 18, 2017; and approve Schedule 4 a Multifamily Residential Demand Response Water Heater Pilot Rider effective July 1, 2017

doc name

ITEM NO. CA7

PUBLIC UTILITY COMMISSION OF OREGON
CONFIDENTIAL STAFF REPORT
PUBLIC MEETING DATE: September 20, 2022

REGULAR ____ CONSENT X EFFECTIVE DATE N/A

DATE: August 29, 2022

TO: Public Utility Commission

FROM: Kathy Zarate and Nick Sayen

THROUGH: Bryan Conway, Marc Hellman, and Matt Muldoon **SIGNED**

SUBJECT: PORTLAND GENERAL ELECTRIC:
(Docket No. UM 1827(5))
Requests authorization to defer costs associated with the PGE demand response Water Heater Pilot.

STAFF RECOMMENDATION:

Staff recommends the Commission approve Portland General Electric's (PGE, or Company) request for reauthorization to defer costs associated with its Demand Response Water Heater Pilot for the 12-month period beginning April 18, 2022, through April 17, 2023.

DISCUSSION:

Issue

Whether the Commission should reauthorize PGE's request to defer for later ratemaking treatment the costs associated with its Demand Response Water Heater Pilot (Pilot).

Applicable Law

PGE submitted its deferral application on April 12, 2022, pursuant to ORS 757.259 and OAR 860-027-0300. ORS 757.259 provides the Commission with authority to authorize the deferral of utility revenues and expenses for later inclusion in rates.
OAR 860-027-0300 is the Commission's rule governing the use of deferred accounting by energy and large telecommunications utilities.

Analysis

Background

On June 28, 2017, the Commission approved the original deferral filing for PGE's Demand Response Water Heater Pilot. The purpose of the Pilot is to retrofit existing water heaters in multifamily residences (MFRs) with demand response technology in order to help inform an effective design for a water heater demand response program. Program objectives include quantifying energy consumption that could be shifted to different times, determining appropriate incentive levels for customers, integrating and testing different technologies, and implementing different demand response dispatch strategies.

PGE's 2016 Integrated Resource Plan (IRP) discussed various types of demand response, including those that utilize smart water heaters. Smart water heaters (installed with digital controls and the ability to readily attach communications equipment) are an important demand resource for PGE as it provides system benefits by reducing peak demand.

The Pilot targets MFR housing because of its high concentration of electric water heaters. The Pilot, in addition to installing demand response-enabled technology on existing water heaters, may provide a monetary incentive to MFR property managers to replace aging water heaters with smart water heaters.

MFR demand response water heaters address a hard-to-reach segment of the residential market where few demand response technologies are currently feasible. Water heaters represent a distributed resource, which supports PGE's long-term smart grid initiatives, as each water heater can be controlled to meet specific demand response needs. Water heater demand response is a more flexible resource compared to other forms of demand response because it requires no notification, is a year-round resource, and has minimal customer comfort impact.

In 2018, a vendor for implementation and a Demand Response Management System (DRMS) was selected. Since May 2018, PGE has been successfully testing integration between water heater retrofit switches (a second vendor offering cell-enabled connectivity was selected in October 2019) and the DRMS to control water heaters with the switch.

As of February 2022, the Pilot has deployed 11,703 water heater retrofit switches and 39 new Smart water heaters (which communicate through built-in CTA-2045 enabled devices rather than retrofit switches) across 32 property management companies representing 102 distinct sites.

The Pilot has two types of retrofit switches in the field: Wi-Fi connected, which were the original switches utilized by the Pilot, and cellular-signal connected, which PGE began to deploy in late 2019. Evaluation data has identified that cell-enabled switches have a consistently higher connectivity rate[1] (79 percent season average, in the Company's current filing) than Wi-Fi connected switches. Wi-Fi connectivity has varied over time, improving substantially from early stages of the Pilot to reach over 70 percent, nearly equivalent to cell-enabled switches.[2] However, as noted in the Company's current filing, Wi-Fi connectivity has dropped significantly (50 percent season average).

Staff understands from discussions with the Company this is due to the fact Wi-Fi connected switches require occasional maintenance (such as router rebooting), without which, they are prone to signal degradation. Due to these issues, PGE stopped retrofitting water heaters with Wi-Fi connected devices in October 2019. However, there are several thousand Wi-Fi connected switches deployed in the field, and the Company has communicated to Staff it is evaluating the most cost-effective approach to handling connectivity issues. Staff is eager to hear the outcomes from the Company's evaluation.

The deferred amounts will be recovered in a manner approved by the Commission and consistent with the terms of Schedule 4 and Schedule 135.

Description of Expense
Expenses for this deferral include: the cost of implementing the communication interface; managing defaults or repairs; managing new participant enrollment; software licensing; data plan subscription; customer and property manager incentives; and PGE marketing.

Reason for Deferral
The use of deferred accounting for this Pilot will minimize the frequency of rate changes and match appropriately the costs borne by, and benefits received by customers.

Additionally, PGE seeks reauthorization to defer the expenses associated with its Demand Response Water Heater Pilot. Without reauthorization, this deferral will expire on April 18, 2022. The continuation of the deferral will minimize the frequency of rate changes and match appropriately the costs borne by, and benefits received by customers. The reauthorization will continue to support the use of an automatic adjustment clause rate schedule, which will provide for changes in prices reflecting incremental costs associated with the Pilot.

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[1] Connectivity rate is the percentage of time that a water heater is connected online and is reachable by the DRMS.

[2] See various prior Pilot evaluations filed in UM 1827.

Proposed Accounting
PGE proposes to record the deferred amount as a regulatory asset in FERC Account 182.3, Other Regulatory Assets, with a credit to FERC Account 407.4, Regulatory Credits.

Estimate of Amounts
PGE estimates the incremental costs of the Pilot to be approximately $2.7 million through the end of 2022, as shown in Table 1 below.

Table 1
Pilot Cost By Year ($)

Year	2017 (4 mo.) Actuals	2018 Actuals	2019 Actuals	2020 Actuals	2021 Actuals	2022 Forecast	Total
Pilot Cost	$60,583	1,073,623	2,999,211	1,687,512	2,039,560	2,709,878	10,570,367

Information Related to Future Amortization:
- Earnings review – An earnings review is generally required prior to amortization of deferrals, pursuant to ORS 757.259(5). However, given the types of costs being deferred for a pilot conservation program, an earnings review will not be performed.
- Prudence Review – A prudence review should be performed by the Commission Staff as part of their review of this deferral's annual reauthorization filing or application to update Schedule 135.
- Sharing – There is no sharing under the filed mechanisms.
- Rate Spread/Design – The deferred costs for this Pilot as recovered through Schedule 135 will be allocated to each schedule using the applicable schedule's forecasted energy based on an equal percent of generation revenue applied on a cent per kWh basis to each applicable rate schedule or in a manner approved by the Commission.[3]
- Three Percent Test (ORS 757.259(6)) – The three percent test measures the annual overall average effect on customer rates resulting from deferral amortizations. The three percent test limits (exceptions at ORS 757.259(7) and (8)) the aggregated deferral amortizations during a 12-month period to no more than three percent of the utility's gross revenues for the preceding year. Because PGE is an electric utility, ORS 757.259(8) allows the Commission to consider up to a six percent limit. The limit for these deferrals will be determined at the time of amortization.

[3] Special Condition 1 of schedule 135.

Conclusion

The proposed multifamily residential Demand Response Pilot is testing a path to cost-effectiveness for necessary demand side resource and associated communication infrastructure. The pilot is expected to produce benefits to ratepayers while advancing PGE's long-term demand response capabilities. Staff recommends approval of the request for reauthorization of incremental program costs.

PGE has reviewed this memo and agrees with its contents.

PROPOSED COMMISSION MOTION:

Approve PGE's request for reauthorization to defer costs associated with its Demand Response Water Heater Pilot for the 12-month period beginning April 18, 2022.

PGE UM 1827(5) DR Water Heater Deferral

ITEM NO. CA6

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: August 27, 2019

REGULAR ____ CONSENT _X_ EFFECTIVE DATE ______ April 18, 2019 ______

DATE: August 19, 2019

TO: Public Utility Commission

FROM: Mitchell Moore

THROUGH: Jason Eisdorfer and John Crider **SIGNED**

SUBJECT: PORTLAND GENERAL ELECTRIC: (Docket No. UM 1827(2)) Requests reauthorization to defer costs associated with the PGE Demand Response Water Heater Pilot.

STAFF RECOMMENDATION:

Staff recommends the Commission approve Portland General Electric's (PGE, or Company) request for reauthorization to defer costs associated with its Demand Response Water Heater Pilot for the 12-month period beginning April 18, 2019.

DISCUSSION:

Issue

Whether the Commission should reauthorize PGE's request to defer for later ratemaking treatment the costs associated with its Demand Response Water Heater pilot program.

Applicable Law

PGE submitted its deferral application on April 17, 2019, pursuant to ORS 757.259 and OAR 860-027-0300. ORS 757.259 provides the Commission with authority to authorize the deferral of utility revenues and expenses for later inclusion in rates. OAR 860-027-0300 is the Commission's rule governing the use of deferred accounting by energy and large telecommunications utilities.

Analysis

Background
On June 28, 2017, the Commission approved the original deferral filing for PGE's Demand Response Water Heater Pilot. The purpose of the program is to retrofit existing water heaters in multifamily residences (MFRs) with demand response technology in order to help inform an effective design for a water heater demand response program, quantify energy consumption that can be shifted to different times, determine appropriate incentive levels for customers, integrate and test different technologies, and implement different demand response dispatch strategies.

PGE's 2016 Integrated Resource Plan (IRP) discussed various types of demand response, including those that utilize smart water heaters. Smart water heaters (installed with digital controls and the ability to readily attach communications equipment) are an important demand resource for PGE and present a wide array of use cases such as load shedding, load shifting and providing ancillary services.

The program targets MFR housing because of its high concentration of electric water heaters. The pilot, in addition to installing demand response-enabled technology on existing water heaters, also provides a monetary incentive to MFR property managers to replace aging water heaters with demand response capable water heaters (i.e., smart water heaters).

MFR demand response water heaters address a hard-to-reach segment of the residential market where few demand response technologies are currently feasible. Water heater demand response also supports PGE's mid-term demand-side management initiatives by allowing the researching of synergies between water heater demand response and smart thermostat programs. Further, water heaters represent a distributed resource, which supports PGE's long-term smart grid initiatives, as each water heater can be controlled to meet specific demand response needs. Finally, water heater demand response is a more flexible resource compared to other forms of demand response because it requires no notification, is a year-round resource, and has minimal customer comfort impact.

In 2018 PGE selected both a vendor for implementation and a Demand Response Management System (DRMS) vendor. Since May 2018, PGE has been successfully testing integration between the water heater retrofit switch and the DRMS.

PGE states in its filing that the pilot is on track and approximately 2,500 water heater retrofit switches have been installed in 14 distinct properties since the end of March 2019. PGE expects to have a total of 5,300 water heaters online by the end of 2019.

PGE UM 1827(2)
August 19, 2019
Page 3

Description of Expense
Expenses for this deferral include: the cost of implementing the communication interface; managing defaults or repairs; and managing new participant enrollment; software licensing; data plan subscription; and PGE marketing.

Reason for Deferral
The use of deferred accounting for this pilot will minimize the frequency of rate changes and match appropriately the costs borne by and benefits received by customers.

Proposed Accounting
PGE proposes to record the deferred amount as a regulatory asset in FERC account 182.3, Other Regulatory Assets, with a credit to FERC account 456, Other Revenue.

Estimate of Amounts
PGE estimates the incremental costs of the pilot will be approximately $3.5 million through the end of 2019, as illustrated in the following table:

Year	2017 Actual	2018 Actual	2019 Forecast	2020 Forecast	Total
Pilot Cost	$93,970	$1,592,378	$3,494,260	$3,555,770	$8,536,378

Information Related to Future Amortization

- Earnings review – An earnings review is generally required prior to amortization of deferrals, pursuant to ORS 757.259(5). However, because this is associated with the Schedule 135 automatic adjustment clause, an earnings review will not be performed.

- Prudence Review – A prudence review is required prior to amortization and should include the verification of the accounting methodology used to determine the final amortization balance. In addition, PGE will submit a pilot evaluation report that will provide detailed cost summaries, estimated kW shifting and the result of customer surveys.

- Sharing – There is no sharing under the filed mechanisms.

- Rate Spread/Design – The demand response pilot amortizations will be spread as specified in Schedule 135.

- Three Percent Test (ORS 757.259(6)) – The three percent test measures the annual overall average effect on customer rates resulting from deferral amortizations. The three percent test limits (exceptions at ORS 757.259(7) and (8)) the aggregated deferral amortizations during a 12-month period to no more than three percent of the utility's gross revenues for the preceding year. Because PGE is an electric utility, ORS 757.259(8) allows the Commission to consider up to a six percent limit. The limit for these deferrals will be determined at the time of amortization.

Conclusion

The proposed multifamily residential demand response pilot is a cost effective investment in a necessary demand side resource and associated long term communication infrastructure. The program is expected to produce net benefits to ratepayers while advancing PGE's demand response capabilities. Staff recommends approval of the request for reauthorization of incremental program costs.

PROPOSED COMMISSION MOTION:

Approve PGE's application to defer the costs associated with the Demand Response Water pilot program, for the 12-month period beginning April 18, 2019.

ITEM NO. CA2

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: January 28, 2020

REGULAR ____ **CONSENT** __X__ **EFFECTIVE DATE** **February 1, 2020**

DATE: January 14, 2020

TO: Public Utility Commission

FROM: John Fox

THROUGH: Michael Dougherty and Marianne Gardner **SIGNED**

SUBJECT: PORTLAND GENERAL ELECTRIC:
(Docket Nos. UM 2037 and UE 368/Advice No. 19-25)
Oregon Corporate Activity Tax - Application for Deferral, Balancing Account, New Tariff, and Automatic Adjustment Clause.

STAFF RECOMMENDATION:

Approve Portland General Electric's (PGE or Company) application requesting authorization for a deferred account beginning on January 1, 2020, and a new tariff, Schedule 131, implementing a rate schedule, balancing account, and automatic adjustment clause for the Oregon Corporate Activity Tax (OCAT or CAT) with the condition that the tariff will terminate and the tax will be included in base rates at a future date to be agreed upon by the parties.

DISCUSSION:

Issue

Whether the Commission should approve PGE's application for deferred accounting and a new tariff Schedule 131 – Oregon Corporate Activity Tax Recovery as filed.

Applicable Rule or Law

Beginning with the date of the Application, the Commission may approve the deferral of identifiable utility expenses or revenues, the recovery or refund of which the Commission finds should be deferred in order to minimize the frequency of rate changes for the fluctuation of rate levels or to match appropriately the costs borne by and benefits received by ratepayers. ORS 757.269(2)(e) and (4). Unless subject to an automatic adjustment clause under ORS 757.210(1), amounts deferred are allowed in rates to the extent authorized by the Commission in a proceeding under ORS 757.210 to change rates and upon review of the utility's earnings at the time of application to amortize the deferral. ORS 757.259(4); OAR 860-027-0300(9). The Commission's final determination on the amount of deferrals allowable in the rates of the utility is subject to a finding by the Commission that the amount was prudently incurred by the utility. ORS 757.259(5).

Under ORS 757.205(1), a public utility must file schedules showing all rates, tolls, and charges for service that have been established and are in force at the time. The Commission may approve tariff changes if they are deemed to be fair, just, and reasonable. ORS 757.210. Tariff revisions or corrections may be made by filing revised sheets with the information required under the Commission's administrative rules, including OAR 860-022-0005 and OAR 860-022-0025. Filings that make any change in rates, tolls, charges, rules, or regulations must be filed with the Commission at least 30 days before the effective date of the changes. ORS 757.220.

OAR 860-022-0025(2) specifically requires that each energy utility changing existing tariffs or schedules must include in its filing a statement plainly indicating the increase, decrease, or other change made with the filing; the number of customers affected by the proposed change and the resulting change in annual revenue; and the reasons or grounds relied upon in support of the proposed change.

Unless subject to an automatic adjustment clause under ORS 757.210(1), amounts deferred are allowed in rates to the extent authorized by the Commission in a proceeding under ORS 757.210 to change rates and upon review of the utility's earnings at the time of application to amortize the deferral. ORS 757.259(4); OAR 860-027-0300(9).

<u>Analysis</u>

Background
The 2019 Oregon Legislative Assembly approved a new Corporate Activities Tax effective January 1, 2020.[1]

[1] See Oregon Laws 2019 Chapter 122, Sections 58-79 and Chapter 579, Sections 50-60.

The tax is imposed on the privilege of doing business in Oregon and is not a transactional tax nor an income tax.[2] However, apportionment and tax administration will occur pursuant to existing income tax statues.[3]

The tax is in addition to any other taxes or fees imposed by the State of Oregon[4] and will be imposed at a rate of $250 plus 0.57 percent of taxable commercial activity in excess of $1 million each year.[5] Taxable commercial activity is defined as commercial activity sourced in this state less a deduction for 35 percent of the greater of "cost inputs" or "labor costs."

PGE's Initial and Revised Filings
On November 12, 2019, the Company filed an application for deferral that will support an automatic adjustment clause rate schedule with an associated balancing account (UM 2037) and another application, Advice No. 19-25 Schedule 131 – Oregon Corporate Activity Tax Recovery (UE 368), effective January 1, 2020.

On December 4, 2019, the Company filed replacement tariff sheets changing the effective date to February 1, 2020, to provide additional time for review.

The Company requests that the applications be considered simultaneously.[6]

The Company's application states:

> The proposed Schedule 131 prices are applied on a percentage basis of customers' bills with the exceptions outlined in the proposed tariff, similar to PGE Schedule 106 Multnomah County Business Income Tax for customers in Multnomah County.

And states:

> PGE's estimate of the CAT for 2020 is $7.4 million. However, given that this is a new tax and the ultimate tax amount remains uncertain the actual tax amount may differ. PGE's proposed balancing account and automatic adjustment clause will allow PGE to true up the differences between PGE's estimated CAT collected under Schedule 131 and its actual CAT expense. These differences will be

[2] Chapter 122, Section 63.
[3] Chapter 122, Section 64 and 74.
[4] Id.
[5] Chapter 122, Section 64.
[6] UM 2037/UE 368 – PGE's applications at 1.

credited or charged to customers through an annual update of Schedule 131 prices.

In Staff's view, the new OCAT is fundamentally different from the MCBIT in that it is a statewide tax that does not need to be isolated and recovered from a specific subset of the Company's customer base as is required for the MCBIT under OAR 860-022-0045. Also, as noted above, the tax is in addition to any other taxes or fees imposed by the State of Oregon. In other words, from a ratemaking perspective, the OCAT is simply an increase in the overall state tax burden. Accordingly, Staff's position is the OCAT ought to be estimated and rolled into base rates as soon as practicable.

Administrative Uncertainty
The Oregon Department of Revenue has issued limited taxpayer guidance for the OCAT and expects to release draft administrative rules through the spring of 2020.

Because the law is new and complex, the precise amount of PGE's OCAT expenses are not yet clear. Accordingly, the preliminary calculations provided with this filing reflect high level estimates that will likely differ from the actual amount of OCAT expense incurred.

All Party Workshop
On December 13, 2019, Portland General Electric (PGE) hosted a workshop to discuss the OCAT filings which was attended by PGE, PacifiCorp, Staff, Oregon Citizens' Utility Board (CUB), and Alliance of Western Energy Consumers (AWEC).

Notwithstanding mention of MCBIT in the various filings, both Companies expressed a willingness to roll the OCAT into base rates when appropriate, the utilities will work in good faith to make that determination, and the utilities will continue to file deferrals for taxes each year until rolled into base rates. In particular, PGE and PacifiCorp cited the following significant uncertainties which need to be resolved prior to inclusion of the OCAT in base rates:

- How the numerous exclusions from the definition of commercial activity[7] will apply to the Companies' various revenue streams.
- The specifics of what will be allowable with regard to calculating the deduction for 35 percent of the greater of "cost inputs" or "labor costs".

Staff, CUB, and AWEC expressed a willingness to support the proposed rate recovery mechanism with the understanding the OCAT will be rolled into base rates as soon as practicable and a willingness to work in good faith to make that determination.

[7] See Chapter 122, Section 58 as amended by Chapter 579, Section 50.

PGE UM 2037 and UE 368/Advice No. 19-25
January 14, 2020
Page 5

Deferral Amount and Proposed Tariff
PGE's estimate of the CAT for 2020 is $7.4 million. The proposed OCAT recovery rate for 2020 based on this amount is 0.395 percent of the total billed amount to the Customer excluding the RPA Credit (Schedule 102), Public Purpose Charge (Schedule 108), Energy Efficiency Funding Adjustment (Schedule 109), Low Income Assistance Charge (Schedule 115) and all other separately stated taxes.

The Company also states that the proposed Schedule 131 rate change will result in a 0.4 percent overall rate increase for approximately 900,000 Customers. A typical Schedule 7 Residential Customer consuming 800 kWh monthly will see a bill increase of approximately $0.38.

Staff notes that the 0.395 percent tariff rate is less than the 0.57 percent incremental OCAT tax rate, with the difference being attributable mostly to the deduction for 35 percent of the greater of “cost inputs” or “labor costs”. Staff has reviewed the Company’s calculations underlying the proposed tariff and considers them to be a reasonable estimate given the uncertainties discussed above.

The OCAT is new and, in Staff’s view, an extenuating circumstance that was not foreseen in the Company’s most recent general rate case, therefore a lower standard of material harm should be applied when evaluating the deferral.[8] Also, the circumstances are similar to the recent deferral of Tax Cut and Jobs Act benefits where the Company agreed to forgo the review of the utility’s earnings at the time of application to amortize the deferral in favor of customers.[9]

Staff believes approval of the requested relief is a reasonable outcome under the circumstances and will result in fair, just, and reasonable rates.

Staff also notes that, as a result of the delayed effective date, the initial tariff will be set to recover $7.4 million over the 11-month period beginning February 1, 2020, rather than 12 months as originally filed. Subsequent years will recover 12 months of taxes over the calendar year.

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[8] See *In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Application for the Deferral of Storm-Related Restoration Costs,* Docket No. UM 1817, Order No. 19-274, at 3.
[9] See *In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Application for Authorization to Defer Benefits Associated with the US Tax Reconciliation Act,* Docket No. UM 1920, Order No. 18-459, at 5.

Conclusion

For the reasons stated above, Staff recommends the Commission approve the Company's application to establish a new tariff Schedule 131 – Oregon Corporate Activity Tax Recovery effective February 1, 2020, and the associated deferral, balancing account, and automatic adjustment clause with the condition that the tariff will terminate and the tax will be included in base rates at a future date to be agreed upon by the parties.

PROPOSED COMMISSION MOTION:

Approve Portland General Electric's application requesting authorization for deferred accounting beginning on January 1, 2020, and a new tariff, Schedule 131, implementing a rate schedule, balancing account, and automatic adjustment clause for the Oregon Corporate Activity Tax with the condition that the tariff will terminate and the tax will be included in base rates at a future date to be agreed upon by the parties.

CA2 UM 2037 UE 368 PGE OCAT.docx

ITEM NO. CA6

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: January 26, 2021

REGULAR ____ CONSENT _X_ EFFECTIVE DATE ___January 1, 2021___

DATE: January 12, 2021

TO: Public Utility Commission

FROM: John Fox

THROUGH: Bryan Conway and John Crider **SIGNED**

SUBJECT: PORTLAND GENERAL ELECTRIC:
(Docket No. UM 2037(1))
Application for Reauthorization to Defer Costs Associated with the Oregon Corporate Activities Tax.

STAFF RECOMMENDATION:

Approve Portland General Electric's (PGE or Company) application for reauthorization to defer costs for the Oregon Corporate Activities Tax (CAT), estimated to be approximately $7.5 million, beginning January 1, 2021, through December 31, 2021.

DISCUSSION:

Issue

Whether the Commission should approve PGE's application for reauthorization to defer costs for the Oregon Corporate Activities Tax, estimated to be approximately $7.5 million in 2021.[1]

Applicable Rule or Law

Beginning with the date of the Application, the Commission may approve the deferral of identifiable utility expenses or revenues, the recovery or refund of which the Commission finds should be deferred in order to minimize the frequency of rate changes for the fluctuation of rate levels or to match appropriately the costs borne by and benefits received by ratepayers. ORS 757.259(2)(e) and (4). Unless subject to an automatic adjustment clause under ORS 757.210(1), amounts deferred are allowed in

[1] Application at 4.

rates to the extent authorized by the Commission in a proceeding under ORS 757.210 to change rates and upon review of the utility's earnings at the time of application to amortize the deferral. ORS 757.259(4); OAR 860-027-0300(9). The Commission's final determination on the amount of deferrals allowable in the rates of the utility is subject to a finding by the Commission that the amount was prudently incurred by the utility. ORS 757.259(5).

Analysis

Background

The 2019 Oregon Legislative Assembly approved a new Corporate Activity Tax effective January 1, 2020.

The tax is imposed on the privilege of doing business in Oregon, based on Oregon-sourced commercial activities and is not a transactional tax nor an income tax—it is a modified gross-receipts tax. However, apportionment and tax administration will occur pursuant to existing income tax statues.

The tax is in addition to any other taxes or fees imposed by the State of Oregon and will be imposed at a rate of $250 plus 0.57 percent of taxable commercial activity in excess of $1 million each year. Taxable commercial activity is defined as commercial activity sourced in this state less a subtraction for 35 percent of the greater of "cost inputs" or "labor costs."[2]

In Order No. 20-029, the Commission approved PGE's application requesting authorization for deferred accounting beginning on January 1, 2020, and a new tariff, Schedule 131, implementing a rate schedule, balancing account, and automatic adjustment clause for the Oregon Corporate Activity Tax with the condition that the tariff will terminate and the tax will be included in base rates at a future date to be agreed upon by the parties.

Description of Expense and Reason for Deferral

The Company states:

> This deferral would continue the use of an automatic adjustment clause and be subject to annual renewals until the Oregon CAT is included in base rates at a future date. In accordance with Commission authorized accounting, amounts in the Oregon CAT balancing account will continue to roll forward and can have either positive or negative (i.e., debit or credit) balances.[3]

[2] ORS 317A.125 and 317A.119.
[3] Application at 3.

And further states:

> [T]he imposition of this tax was unforeseen and unpredictable, thus PGE was unable to include this in a prior forecast or include within a prior rate proceeding. The continuation of the deferral will minimize the frequency of rate changes and match appropriately the costs borne by and benefits received by customers. Approving the Application will support continued use of an automatic adjustment clause associated with PGE Schedule 131.

Proposed Accounting
PGE proposes to continue to defer the tax payments as debits to FERC Account 242 (Current Regulatory Liability) and credits to FERC Account 407.4 (Regulatory Credit). Amortization through Schedule 131 is credited to FERC Account 242 and debited to FERC Account 407.4. Interest is accrued on the balance at the approved modified blended treasury rate.[4]

Estimated Deferral in Authorization Period
PGE estimates the amount to be deferred during the 12-month period beginning January 1, 2021, to be approximately $7.5 million dollars.

Information Related to Future Amortization

- Earnings Review – Cost recovery associated with this deferral will be subject to an automatic adjustment clause, PGE Schedule 131, and would not be subject to an earnings review under ORS 757.259.
- Prudence Review – A prudence review should be performed by the Commission Staff as part of their review of PGE's payment of CAT expenses and cost recovery.
- Sharing – All prudently incurred costs are to be recoverable by PGE with no sharing mechanism.
- Rate Spread/Design – The rate spread/rate design will be performed in accordance with Schedule 131 as a percentage of revenues with some exclusions.

<u>Conclusion</u>

Staff concludes that approval of this deferral for the period January 1, 2021, through December 31, 2021, is consistent with the resolution of the CAT previously approved in Order No. 20-029 and that deferral of these amounts will match costs borne by and benefits received by ratepayers.

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[4] Application at 4.

Additionally, in Staff's view, the amount of ongoing CAT expense is now reasonably estimable and should be rolled into base rates in the Company's next general rate case, consistent with the Commission's treatment of the CAT for other regulated utilities.

PROPOSED COMMISSION MOTION:

Approve PGE's application for reauthorization to defer for later ratemaking treatment costs for the Oregon Corporate Activities Tax, estimated to be approximately $7.5 million beginning January 1, 2021, through December 31, 2021.

UM 2037(1) PGE OCAT 2021 OCAT Deferral.docx

ITEM NO. CA4

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: February 22, 2022

REGULAR ____ **CONSENT** __X__ **EFFECTIVE DATE** ____**January 1, 2022**____

DATE: February 8, 2022

TO: Public Utility Commission

FROM: John Fox

THROUGH: Bryan Conway, Marc Hellman, and Matt Muldoon **SIGNED**

SUBJECT: PORTLAND GENERAL ELECTRIC:
(Docket No. UM 2037(2))
Application for Reauthorization to Defer Costs Associated with the Oregon Corporate Activities Tax.

STAFF RECOMMENDATION:

Approve Portland General Electric's (PGE or Company) application for reauthorization to defer costs for the Oregon Corporate Activities Tax (OCAT), estimated to be approximately $2.8 million, beginning January 1, 2022 through December 31, 2022.

DISCUSSION:

Issue

Whether the Commission should approve PGE's application for reauthorization to defer costs for the Oregon Corporate Activities Tax, estimated to be approximately $2.8 million until the rate effective date of the Company's pending general rate revision.[1]

Applicable Rule or Law

Beginning with the date of the Application, the Commission may approve the deferral of identifiable utility expenses or revenues, the recovery or refund of which the Commission finds should be deferred in order to minimize the frequency of rate changes for the fluctuation of rate levels or to match appropriately the costs borne by and benefits received by ratepayers. ORS 757.259(2)(e) and (4). Unless subject to an automatic adjustment clause under ORS 757.210(1), amounts deferred are allowed in

1 Application at 4.

rates to the extent authorized by the Commission in a proceeding under ORS 757.210 to change rates and upon review of the utility's earnings at the time of application to amortize the deferral. ORS 757.259(4); OAR 860-027-0300(9). The Commission's final determination on the amount of deferrals allowable in the rates of the utility is subject to a finding by the Commission that the amount was prudently incurred by the utility. ORS 757.259(5).

Analysis

Background
The 2019 Oregon Legislative Assembly approved a new Corporate Activity Tax effective January 1, 2020.

The tax is imposed on the privilege of doing business in Oregon, based on Oregon-sourced commercial activities, and is not a transactional tax nor an income tax—it is a modified gross-receipts tax. However, apportionment and tax administration will occur pursuant to existing income tax statues.

The tax is in addition to any other taxes or fees imposed by the State of Oregon and will be imposed at a rate of $250 plus 0.57 percent of taxable commercial activity in excess of $1 million each year. Taxable commercial activity is defined as commercial activity sourced in this state less a subtraction for 35 percent of the greater of "cost inputs" or "labor costs."[2]

In Order No. 20-029, the Commission approved PGE's application requesting authorization for deferred accounting beginning on January 1, 2020, and a new tariff, Schedule 131, implementing a rate schedule, balancing account, and automatic adjustment clause for the Oregon Corporate Activity Tax with the condition that the tariff will terminate and the tax will be included in base rates at a future date to be agreed upon by the parties.

A stipulation has been filed in the Company's pending general rate case wherein the stipulating parties agree to move the OCAT to base rates in an amount of $8,375,000 annually.[3] As stated above, PGE expects to defer approximately $2.8 million between January 1, 2022 and the anticipated effective date of the general rate revision on May 9, 2022.

[2] ORS 317A.125 and 317A.119.
[3] UE 394– December 2, 2021 Partial Stipulation at 4.

PGE Docket No. UM 2037(2)
February 8, 2022
Page 3

Description of Expense and Reason for Deferral
The Company states:

> This deferral would continue the use of an automatic adjustment clause until the OCAT is included in base rates as specified above.[4]

And further states:

> PGE seeks reauthorization to continue to defer costs associated with the OCAT until it is moved into base rates. As mentioned above, the imposition of this tax was unforeseen and unpredictable, thus PGE was unable to include this in a prior forecast or include it within a prior rate proceeding. The continuation of the deferral will minimize the frequency of rate changes and match appropriately the costs borne by and benefits received by customers. Approving the Application will support the continued use of an automatic adjustment clause associated with PGE Schedule 131.[5]

Proposed Accounting
PGE proposes to continue to defer the tax payments as debits to FERC Account 242 (Current Regulatory Liability) and credits to FERC Account 407.4 (Regulatory Credit). Amortization through Schedule 131 is credited to FERC Account 242 and debited to FERC Account 407.4. Interest is accrued on the balance at the approved modified blended treasury rate.[6]

Estimated Deferral in Authorization Period
PGE estimates the amount to be deferred during the 12-month period beginning January 1, 2022, to be approximately $2.8 million dollars.

Information Related to Future Amortization
- Earnings Review – Cost recovery associated with this deferral will be subject to an automatic adjustment clause, PGE Schedule 131, and would not be subject to an earnings review under ORS 757.259.
- Prudence Review – A prudence review should be performed by the Commission Staff as part of their review of PGE's payment of OCAT expenses and cost recovery.
- Sharing – All prudently incurred costs are to be recoverable by PGE with no sharing mechanism.

[4] Application at 3.
[5] Id.
[6] Application at 4.

- Rate Spread/Design – The rate spread/rate design will be performed in accordance with Schedule 131 as a percentage of revenues with some exclusions.

Conclusion

Staff concludes that approval of this deferral for the period January 1, 2022 through December 31, 2022, is consistent with the Commission's prior decisions related to OCAT and that deferral of these amounts will match costs borne by and benefits received by ratepayers.

The Company has reviewed a draft of this memo and has not noted any concerns.

PROPOSED COMMISSION MOTION:

Approve PGE's application for reauthorization to defer for later ratemaking treatment costs for the Oregon Corporate Activities Tax, estimated to be approximately $2.8 million beginning January 1, 2022 through December 31, 2022.

PGE UM 2037(2) OCAT Deferral.docx

ITEM NO. CA5

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: January 26, 2021

REGULAR ____ CONSENT _X_ EFFECTIVE DATE _____January 1, 2021_____

DATE: January 12, 2021

TO: Public Utility Commission

FROM: John Fox

THROUGH: Bryan Conway and John Crider **SIGNED**

SUBJECT: PORTLAND GENERAL ELECTRIC:
(Docket Nos. UM 2131 and ADV 1221/Advice No. 20-48)
Application for Deferral of Costs and Revenues Associated with the Metro Supportive Housing Services Tax, New Tariff, and Automatic Adjustment Clause.

STAFF RECOMMENDATION:

Approve Portland General Electric's (PGE or Company) application requesting authorization for a deferred account for the 12-month period beginning on January 1, 2021.

Approve PGE's Advice No. 20-48, creating Schedule 103, for the collection of the Metro Supportive Housing Services Tax from customers that reside within the Metro jurisdiction.

DISCUSSION:

Issue

Whether the Commission should approve PGE's application for deferred accounting for the 12-month period beginning January 1, 2021, related to the Metro Supportive Housing Services Tax.

Whether the Commission should approve PGE's proposed Schedule 103 – Metro Supportive Housing Services Business Income Tax Recovery – which seeks to recover via an Automatic Adjustment Clause the annual forecast amount of the Metro

Supporting Housing Services Tax and a true-up of the previous year's over- or under-recovery of tax relative to the Company's actual tax liability.

Applicable Rule or Law

Beginning with the date of the Application, the Commission may approve the deferral of identifiable utility expenses or revenues, the recovery or refund of which the Commission finds should be deferred in order to minimize the frequency of rate changes for the fluctuation of rate levels or to match appropriately the costs borne by and benefits received by ratepayers. ORS 757.259(2)(e) and (4). Unless subject to an automatic adjustment clause under ORS 757.210(1), amounts deferred are allowed in rates to the extent authorized by the Commission in a proceeding under ORS 757.210 to change rates and upon review of the utility's earnings at the time of application to amortize the deferral. ORS 757.259(4); OAR 860-027-0300(9). The Commission's final determination on the amount of deferrals allowable in the rates of the utility is subject to a finding by the Commission that the amount was prudently incurred by the utility. ORS 757.259(5).

Under ORS 757.205(1), a public utility must file schedules showing all rates, tolls, and charges for service that have been established and are in force at the time. The Commission may approve tariff changes if they are deemed to be fair, just, and reasonable. ORS 757.210. Tariff revisions or corrections may be made by filing revised sheets with the information required under the Commission's administrative rules, including OAR 860-022-0005 and OAR 860-022-0025. Filings that make any change in rates, tolls, charges, rules, or regulations must be filed with the Commission at least 30 days before the effective date of the changes. ORS 757.220.

ORS 757.210(1)(b) defines "automatic adjustment clause" as "a provision of a rate schedule that provides for rate increases or decreases or both, without prior hearing, reflecting increases or decreases or both in costs incurred, taxes paid to units of government or revenues earned by a utility and that is subject to review by the commission at least once every two years."

ORS 757.269(1) states that "the Public Utility Commission shall act to balance the interests of the customers of the utility and the utility's investors by setting fair, just and reasonable rates that include amounts for income taxes" and "amounts for income taxes included in rates are fair, just and reasonable if the rates include current and deferred income taxes and other related tax items that are based on estimated revenues derived from the regulated operations of the utility."

ORS 757.269(2)(e)(c) furthermore states that hearings to establish new rate schedules "reflect all known changes to tax and accounting laws or policy that would affect the calculated taxes."

OAR 860-022-0025(2) requires that each energy utility changing existing tariffs or schedules must include in its filing a statement plainly indicating the increase, decrease, or other change made with the filing; the number of customers affected by the proposed change and the resulting change in annual revenue; and the reasons or grounds relied upon in support of the proposed change.

OAR 860-022-0045 states that, in part, if any county in Oregon imposes or increases taxes or licensing, franchise, or operating permit fees, the utility required to pay such taxes or fees shall collect the amount from its customers within the county imposing such taxes or fees.

Analysis

Background

In May 2020, voters in Multnomah County, Washington County, and Clackamas County approved a measure to raise money for supportive housing services for people experiencing homelessness or at risk of experiencing homelessness in the greater Portland area. The program is administered by the Portland Area Metropolitan Service District (Metro) and funded by a 1 percent tax on taxable income of more than $125,000 for individuals and $200,000 for couples filing jointly, and a 1 percent tax on profits from businesses with gross receipts of more than $5 million. The taxes are effective for tax years beginning on and after January 1, 2021.

Metro is organized under the provisions of Oregon Revised Statutes Chapter 268 and the Metro Charter. The Metro Council is the governing body of Metro. On December 17, 2020, the council adopted ordinances necessary to implement the new tax.[1] However, administrative rules are still pending and are expected to be issued in early 2021.

PGE Filings

The Company requests that the Commission consider the advice filing and application for deferred accounting simultaneously.

On November 13, 2020, the Company filed an application (docketed at UM 2131) requesting:

[1] Ordinance Nos. 20-1452, 20-1453, and 20-154.

PGE Docket Nos. UM 2131 and ADV 1221/Advice No. 20-48
January 12, 2020
Page 4

> An accounting order authorizing PGE to defer for later rate-making treatment costs and revenues associated with the Metro Supportive Housing Services (MSHS) Tax pursuant to Metro Measure 26-210. In addition, this filing is being made to initiate a deferral that will support an automatic adjustment clause rate schedule with an associated balancing account mechanism to track the ongoing costs and recovery amounts related to the MSHS Tax. PGE requests that this deferral be effective as of January 1, 2021, the date the MSHS tax goes into effect.

And which further states:

> To address the cost and recovery associated with the MSHS Tax, PGE proposes to establish a balancing account and mechanism similar to that used for the Multnomah County Business Income Tax (MCBIT – see Docket No. UM 1986 and PGE Schedule 106). Specifically, PGE proposes to defer both the MSHS Tax expense along with the revenues collected from a MCBIT-type tariff. The separate tariff is necessary to collect the MSHS Tax only from the Metro customers to which it applies.

On December 29, 2020, the Company filed Advice No. 20-48, Schedule 103, Metro Supportive Housing Services Business Income Tax (docketed as ADV 1221) to be effective April 1, 2021. The application states the following:

> PGE used the same methodology for estimating the MSHS Business Income Tax that is used to calculate Schedule 106, the Multnomah County Business Income Tax. PGE's estimate of the MSHS for 2021 is $1.5 million. However, given that this is a new tax and the ultimate tax amount remains uncertain the actual tax amount may differ. PGE's proposed balancing account and automatic adjustment clause, will allow PGE to true up the differences between PGE's estimated MSHS collected under Schedule 103 and its actual MSHS expense. These differences will be credited or charged to customers through an annual update of Schedule 103 prices.
>
> The proposed Schedule 103 price is applied on a percentage basis of customers' bills with the exceptions outlined in the proposed tariff, similar to PGE's Schedule 106 Multnomah County Business Income Tax for customers in Multnomah County. PGE is proposing an effective date of April 1, 2021, to allow PGE to update its billing system, so only customers who live within Metro's jurisdiction in Clackamas, Multnomah and Washington Counties will receive the Schedule 103 charge.

> The proposed Schedule 103 price included in this filing was calculated based on revenues received from all customers who live within Clackamas, Multnomah and Washington counties. However, not all customers in those counties are within Metro and PGE is working to identify Customers within Metro. Prior to the April 1, 2021 effective date, PGE will supplement this filing with an updated Schedule 103 price which will only include revenues from customers residing in those counties within Metro's jurisdiction.

To satisfy the requirements of OAR 860-022-0025(2) and 860-22-0030, the Company provides the following information:

> The proposed Schedule 103 rate change will result in a 0.095% overall rate increase for approximately 740,000 Clackamas, Multnomah and Washington County Customers within Metro's jurisdiction. A typical Schedule 7 Residential Customer consuming 800 kWh monthly will see a bill increase of approximately $0.09.

Proposed Accounting
PGE states that tax payments will be debited to FERC Account 242 Current Regulatory Liability and credited to FERC Account 407.4 Regulatory Credit. Tariff revenues will be credited to FERC Account 242 and debited to FERC account 407.4.

Estimated Deferral in Authorization Period
Using PGE's 2019 income tax filing as proxy, PGE estimates the MSHS Tax amount to be deferred during 2021 to be $1.5 million dollars.

Information Related to Future Amortization
- Earnings Review – The MSHS Tax deferral will be subject to an automatic adjustment clause rate schedule, where all associated costs and revenues will flow through the established balancing account, and would not be subject to an earnings review under ORS 757.259.
- Prudence Review – A prudence review should be performed by the Commission Staff as part of their review of PGE's general rate case filings.
- Sharing – All prudently incurred costs are to be recoverable by PGE with no sharing mechanism.
- Rate Spread/Design – The MSHS Tax costs will be allocated among all of PGE's Metro customers on an equal cents per kilowatt-hour basis.

Discussion
Staff concurs with the Company's proposal to structure recovery of the MSHS tax using a mechanism identical to the MCBIT. OAR 860-022-0040 and OAR 860-022-0045

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January 12, 2020
Page 6

pertain to tax recoveries of cities and counties, respectively. While Metro is a unique entity, the tax itself is based on net income rather than a franchise arrangement. In fact, the staff reports associated with the Metro ordinances indicate the Metro Council's intent to adopt an income apportionment method consistent with that used by Multnomah County and the use of the MCBIT as a guide for implementing the MSHS tax.[2]

The Commission recently considered the relationship of Multnomah Business Income Tax (MCBIT) balancing accounts and Automatic Adjustment Clauses (AAC) in Order No. 18-126.[3] In that case, the Commission reaffirmed that a cost of service AAC requires ongoing annual deferrals in conjunction with a balancing account if rates are to be adjusted based on over -or under -collected amounts.[4] As such, ongoing annual deferrals will be necessary for this docket.

PGE has confirmed via informal inquiry that the Company intends to file annual deferral reauthorizations.

The Company's UM 2131 application also indicates that a prudence review will occur in the Company's next general rate case filing. However, the Commission is charged with ensuring that rates are fair, just, and reasonable prior to authorization. As such, with each proposed annual rate change, Staff will review and verify forecast annual amounts to be collected in rates, actual taxes paid the previous year, and the over- or under-collection proposed to be included in rates from the subsequent year.

Conclusion

For the reasons stated above, Staff recommends the Commission approve PGE's request for authorization of a deferred account for the 12-month period beginning on January 1, 2021, and a new tariff, Schedule 103, implementing a rate schedule to recover from customers the Metro Supportive Housing Services Tax subject to the supplemental filing to only include revenues from customers residing in those counties within Metro's jurisdiction as noted in the Company's deferral application.

[2] See Metro Council Meeting Agenda, Ordinance 20-1454 Staff Report, December 17, 2020: https://oregonmetro.legistar.com/View.ashx?M=AO&ID=96448&GUID=f1dd486a-112e-4435-a791-7727520b9f7d&N=TWVldGluZyBQYWNrZXQ%3d accessed December 30, 2020.
[3] See *In the MATTER OF PACIFICORP, dba PACIFIC POWER, Advice No. 18-001 (ADV 726), updates Schedule 103, Multnomah County Business Tax (MCBIT) Rate for 2018*, Docket No. UE 338, Order No. 18-126, Apr 12, 2018.
[4] *Id* at 4.

PROPOSED COMMISSION MOTION:

Approve Portland General Electric's application requesting authorization for a deferred account for the 12-month period beginning on January 1, 2021.

Approve PGE's Advice No. 20-48, implementing Schedule 103, used to collect the Metro Supportive Housing Services Tax from customers residing within the Metro jurisdiction.

UM 2131 ADV 1221 PGE Metro Supportive Housing Services Tax.docx

ITEM NO. CA2

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: March 8, 2022

REGULAR ____ CONSENT X EFFECTIVE DATE January 1, 2022

DATE: February 22, 2022

TO: Public Utility Commission

FROM: John Fox

THROUGH: Bryan Conway, Marc Hellman, and Matt Muldoon **SIGNED**

SUBJECT: PORTLAND GENERAL ELECTRIC COMPANY:
(Docket No. UM 2131(1))
Application for Reauthorization of Deferral of Costs and Revenues Associated with the Metro Supportive Housing Services Tax.

STAFF RECOMMENDATION:

Approve Portland General Electric's (PGE or Company) application requesting authorization for a deferred account for costs and revenues associated with the Metro Supportive Housing Services (MSHS) Tax for the 12-month period beginning on January 1, 2022.

DISCUSSION:

Issue

Whether the Commission should approve PGE's application for deferred accounting for the 12-month period beginning January 1, 2022, related to the Metro Supportive Housing Services (MSHS) Tax.

Applicable Rule or Law

Beginning with the date of the Application, the Commission may approve the deferral of identifiable utility expenses or revenues, the recovery or refund of which the Commission finds should be deferred in order to minimize the frequency of rate changes for the fluctuation of rate levels or to match appropriately the costs borne by and benefits received by ratepayers. ORS 757.259(2)(e) and (4). Unless subject to an automatic adjustment clause under ORS 757.210(1), amounts deferred are allowed in

rates to the extent authorized by the Commission in a proceeding under ORS 757.210 to change rates and upon review of the utility's earnings at the time of application to amortize the deferral. ORS 757.259(4); OAR 860-027-0300(9). The Commission's final determination on the amount of deferrals allowable in the rates of the utility is subject to a finding by the Commission that the amount was prudently incurred by the utility. ORS 757.259(5).

ORS 757.269(1) states that "the Public Utility Commission shall act to balance the interests of the customers of the utility and the utility's investors by setting fair, just and reasonable rates that include amounts for income taxes" and "amounts for income taxes included in rates are fair, just and reasonable if the rates include current and deferred income taxes and other related tax items that are based on estimated revenues derived from the regulated operations of the utility."

OAR 860-022-0045 states that, in part, if any county in Oregon imposes or increases taxes or licensing, franchise, or operating permit fees, the utility required to pay such taxes or fees shall collect the amount from its customers within the county imposing such taxes or fees.

Analysis

Background

In May 2020, voters in Multnomah County, Washington County, and Clackamas County approved a measure to raise money for supportive housing services for people experiencing homelessness or at risk of experiencing homelessness in the greater Portland area. The program is administered by the Portland Area Metropolitan Service District (Metro) and funded by a 1 percent tax on taxable income of more than $125,000 for individuals and $200,000 for couples filing jointly, and a 1 percent tax on profits from businesses with gross receipts of more than $5 million. The taxes are effective for tax years beginning on and after January 1, 2021.

Metro is organized under the provisions of Oregon Revised Statutes Chapter 268 and the Metro Charter. The Metro Council is the governing body of Metro. Beginning in December 2020, the Council has adopted various ordinances and administrative rules necessary to implement the new tax.[1]

[1] https://www.oregonmetro.gov/public-projects/supportive-housing-services-tax/codes-and-rules.

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PGE's Filing
PGE requests an accounting order authorizing PGE to defer for later rate making treatment costs and revenues associated with the Metro Supportive Housing Services (MSHS) Tax pursuant to Metro Measure 26-210. PGE requests that this deferral be subject to an automatic adjustment clause through PGE Schedule 103, and be effective January 1, 2022, through December 31, 2022.[2]

Proposed Accounting
PGE proposes the following MSHS Tax accounting treatment: the balancing account will be recorded in FERC account 242 (Current Regulatory Liability). MSHS payments (i.e., payments to the taxing authority) will be debited to FERC Account 242 and credited to FERC Account 407.4 (Regulatory Credit). MSHS amortization (i.e., revenues collected from PGE's Metro customers via the MSHS Tax tariff) will be credited to FERC Account 242 and debited to FERC Account 407.4. Interest will accrue on the balance at the approved blended treasury rate.

Estimated Deferrals in Authorization Period
PGE estimates the MSHS Tax amount to defer during 2022 to be approximately $0.5 million dollars.

Discussion
OAR 860-022-0040 and OAR 860-022-0045 pertain to tax recoveries of cities and counties, respectively. While Metro is a unique entity, the tax itself is based on net income rather than a franchise arrangement. In fact, its staff reports associated with the Metro ordinances indicate the Metro Council's intent to adopt an income apportionment method consistent with that used by Multnomah County and the use of the Multnomah County Business Income Tax (MCBIT) as a guide for implementing the MSHS tax.[3]

In Order No. 21-029, the Commission approved PGE's Advice No. 20-48, implementing Schedule 103, used to collect the Metro Supportive Housing Services Tax from customers residing within the Metro jurisdiction. The Commission's Order included an automatic adjustment clause and also stated that ongoing annual deferrals will be necessary for this docket.

On November 30, 2021, the Commission approved PGE's Advice No. 21-33, revising the Schedule 103 rate to zero for the collection of the MSHS Tax from customers that reside within the Metro jurisdiction effective for service on or after January 1, 2022. At

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2 Application at 1.
3 See Metro Council Meeting Agenda, Ordinance 20-1454 Staff Report, December 17, 2020: https://oregonmetro.legistar.com/View.ashx?M=AO&ID=96448&GUID=f1dd486a-112e-4435-a791-7727520b9f7d&N=TWVldGluZyBQYWNrZXQ%3d accessed December 30, 2020.

that time, the Company reported a significant carryforward balance in favor of ratepayers due to tariff collections exceeding the amount of tax due in 2021 and estimated the 2022 tax to be $446 thousand which is commensurate with this filing.

Information Related to Future Amortization

- Earnings Review – The MSHS Tax deferral will be subject to an automatic adjustment clause rate schedule, where all associated costs and revenues will flow through the established balancing account and would not be subject to an earnings review under ORS 757.259.
- Prudence Review – A prudence review should be performed by the Commission Staff as part of their review of this deferral's annual reauthorization filings or applications to update Schedule 103.
- Sharing – No sharing mechanism applies to the MSHS tax costs or revenues.
- Rate Spread/Design – The MSHS Tax costs will be charged to customers as a percentage with certain exclusions.
- Three Percent Test (ORS 757.259(6)) – The three percent test measures the annual overall average effect on customer rates resulting from deferral amortizations. The three percent test limits (exceptions at ORS 757.259(7) and (8)) the aggregated deferral amortizations during a 12-month period to no more than three percent of the utility's gross revenues for the preceding year.

<u>Conclusion</u>

For the reasons stated above, Staff recommends the Commission approve PGE's request for reauthorization of a deferred account related to the MSMH Tax for the 12-month period beginning on January 1, 2022.

The Company has had the opportunity to review this memo.

PROPOSED COMMISSION MOTION:

Approve PGE's application requesting authorization for a deferred account for costs and revenues associated with MSHS Tax for the 12-month period beginning on January 1, 2022.

ITEM NO. CA8

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: May 31, 2022

REGULAR ____ **CONSENT** __X__ **EFFECTIVE DATE** ____January 1, 2022____

DATE: May 16, 2022

TO: Public Utility Commission

FROM: Curtis Dlouhy

THROUGH: Bryan Conway, Caroline Moore, and Scott Gibbens **SIGNED**

SUBJECT: PORTLAND GENERAL ELECTRIC:
(Docket No. UM 2218)
Application for Deferred Accounting for Costs and Revenues Associated with the Transportation Electrification Charge.

STAFF RECOMMENDATION:

Approve Portland General Electric's (PGE or Company) application to defer costs and revenues associated with the Transportation Electrification (TE) Charge in House Bill (HB) 2165.

DISCUSSION:

Issue

Whether the Commission should approve PGE's application to defer costs and revenues associated with the TE Charge in HB 2165.

Applicable Rule

PGE makes this filing in accordance with ORS 757.259, OAR 860-027-0300, and HB 2165. ORS 757.259 authorizes the Commission to allow a utility to defer, for later recovery in rates, expenses or revenues in order to minimize frequency of rate changes or to match appropriately the costs borne by and benefits received by customers. OAR 860-027-0300 sets forth several requirements for application to defer.

HB 2165(2)(2) states:

> An electric company that makes sales of electricity to 25,000 or more retail electricity consumers in this state shall collect, through monthly meter charges, an amount from each retail electricity consumer served through the distribution system owned and operated by the electric company. The total amounts collected under this section must be set to one quarter of one percent of the total revenues collected by the electric company from all retail electricity consumers.

HB 2165(2)(3) states:

> Funds collected under subsection (2) of this section must be expended by the electric company to support and integrate transportation electrification and must be consistent with a budget approved by the Public Utility Commission for use of funds collected under this section. Expenditures made by an electric company pursuant to this subsection must be made on elements contained within the electric company's transportation plan accepted by the commission pursuant to ORS 757.357.

Under HB 2165(4)(3)(a), utilities are required to submit a plan that integrates the Company's TE actions to the Commission for acceptance.

<u>Analysis</u>

Background
On May 17, 2021, the Transportation Electrification Rebates and Cost Recovery (HB 2165) was passed. As a result of the passage of this law, electric companies with more than 25,000 Oregon customers are required to collect an amount from their retail customers to support TE investments. The Companies are required to submit their TE investment plans to the Commission for acceptance under HB 2165(4)(3)(a).

HB 2165(2)(2) states that the revenues used to fund these expenditures must come through monthly meter charges through the distribution system and be set at 0.25 percent of the company's revenue from retail electric customers. HB 2165 went into effect on January 1, 2022.

In accordance with HB 2165, ORS 757.259, and OAR 860-027-0300, PGE requested an order authorizing the use of a deferral to track the costs and revenues associated with the TE Charge on December 30, 2021, and an effective date of January 1, 2022.[1] PGE states that this deferral will support a balancing account mechanism to track the

[1] Application, page 2.

ongoing revenues brought in from the monthly meter charge and the costs incurred through TE investments. The deferral will be recovered through Schedule 150 as requested in PGE Advice Filing No. 21-26, which was approved at the December 28, 2021, public meeting.

Relationship to other TE Deferrals
Staff met with the Company on April 18, 2022 to clarify this deferral, particularly how it relates to the two other PGE deferrals regarding transportation electrifications and electric vehicles in UM 1938 and UM 2003. PGE noted that it does not intend to cover the costs of these deferrals with the revenues acquired by the TE charge. There is nothing that requires the utility to use funds collected through the TE charge on existing programs. However, Staff suggested this as an option at the November 30, 2021 Special Public Meeting.[2]

Reason for Deferral
In its application, PGE states that granting this deferral will minimize the frequency of rate changes and match appropriately the costs and benefits received by customers.[3]

Proposed Accounting
PGE intends to record the balancing account in FERC Account 242 (Current Regulatory Liabilities). The TE Charge payments, i.e. the money spent to invest in TE programs, will be debited to FERC Account 242 and credited to FERC Account 407.4 (Regulatory Credit). TE Charge amortization, i.e. revenues collected from PGE customers to support TE investments, will be credited to FERC Account 242 and debited to FERC Account 407.4.[4]

Estimate of Amounts
PGE expects that approximately $5.2 million will be collected from customers through the TE charge in 2022. The money spent on TE programs is not known at this time, and will be approved in a separate, forthcoming docket where PGE will submit its TE budget.

Information Related to Future Amortization

- Earnings review – No earnings review is applicable due to the AAC.

- Prudence Review – A prudence review will be performed when updating the amounts for amortization as part of the AAC.

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2 See Page 7 of Item No. RA2 Staff Report at the November 30, 2021, Special Public Meeting.
3 Application, page 3.
4 *Id.*

- Sharing – All prudently incurred costs are recoverable by PGE with no sharing mechanism.

- Rate Spread/Design – Costs will be allocated to each schedule using the applicable schedule's forecasted energy on the basis of an equal percent of revenue applied on a cents-per-kWh basis.

- Three Percent Test (ORS 757.259(6)) – Future amortization will be subject to the three percent test in accordance with ORS 757.259 (7) and (8).

<u>Conclusion</u>

Approval of this deferral is consistent with HB 2165 and past Commission activities regarding transportation electrification. Staff recommends that the Commission approve PGE's application to defer costs and revenues associated with the TE charge in HB 2165.

PROPOSED COMMISSION MOTION:

Approve PGE's application to defer costs and revenues associated with the TE Charge in HB 2165.

ITEM NO. CA3

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: August 8, 2023

REGULAR ____ **CONSENT** __X__ **EFFECTIVE DATE** __________N/A__________

DATE: July 28, 2023

TO: Public Utility Commission

FROM: Kathy Zarate

THROUGH: Bryan Conway and Marc Hellman **SIGNED**

SUBJECT: PORTLAND GENERAL ELECTRIC:
(Docket No. UM 2218(1))
Application for Deferred Accounting for Costs and Revenues Associated with the Transportation Electrification Charge.

STAFF RECOMMENDATION:

Staff recommends the Commission approve Portland General Electric's (PGE or Company) application to defer costs and revenues associated with the Monthly Meter Charge (MMC) required by House Bill (HB) 2165 beginning January 1, 2023, through December 31, 2023.

DISCUSSION:

Issue

Whether the Commission should approve PGE's application to defer costs and revenues associated with the MMC required by HB 2165.

Applicable Rule or Law

PGE makes this filing in accordance with ORS 757.259, OAR 860-027-0300, and HB 2165. ORS 757.259(2)(e) authorizes the Commission to allow a utility to defer identifiable utility expenses or revenues for later recovery in rates to minimize the frequency of rate changes or to match appropriately the costs borne by and benefits received by ratepayers.

OAR 860-027-0300(3) sets forth the requirements for application to defer, which include:

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July 28, 2023
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> (a) A description of the utility expense or revenue for which deferred accounting is requested;
>
> (b) The reason(s) deferred accounting is being requested and a reference to the section(s) of ORS 757.259 or 759.200 under which deferral may be authorized;
>
> (c) The account proposed for recording of the amounts to be deferred and the account which would be used for recording the amounts in the absence of approval of deferred accounting;
>
> (d) An estimate of the amounts to be recorded in the deferred account for the 12-month period subsequent to the application; and
>
> (e) A copy of the notice of application for deferred accounting and list of persons served with the notice.

HB 2165(2)(2)[1] states:

> An electric company that makes sales of electricity to 25,000 or more retail electricity consumers in this state shall collect, through monthly meter charges, an amount from each retail electricity consumer served through the distribution system owned and operated by the electric company. The total amounts collected under this section must be set to one quarter of one percent of the total revenues collected by the electric company from all retail electricity consumers.

HB 2165(2)(3)[2] states:

> Funds collected under subsection (2) of this section must be expended by the electric company to support and integrate transportation electrification and must be consistent with a budget approved by the Public Utility Commission for use of funds collected under this section. Expenditures made by an electric company pursuant to this subsection must be made on elements contained within the electric company's transportation plan accepted by the commission pursuant to ORS 757.357.

ORS 757.357(3)(a) requires utilities to develop a plan that integrates the Company's TE actions and submit such plan to the Commission for acceptance.

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[1] Oregon Laws 2021, chapter 95, section 2, *complied as a note after* ORS 757.357 (2021).
[2] Oregon Laws 2021, chapter 95, section 3, *complied as a note after* ORS 757.357 (2021).

Analysis

Background
On May 26, 2021, the Governor of Oregon signed into law House Bill (HB) 2165 requiring electric companies with more than 25,000 electricity consumers to collect an amount to support transportation electrification. The law went into effect on January 1, 2022. The total amounts collected under this law must be set to one quarter of one percent of the total revenues collected by the electric company from all retail electricity consumers.

Funds collected must be expended by the electric company to support and integrate transportation electrification, consistent with a budget approved by the Commission. The Commission approved PGE's application for the deferral of costs and revenues associated with the MMC for the period of January 1, 2022, through December 31, 2022, in Order No. 22-200.

> PGE is not including any forecast or estimate of the MMC in customer prices through a general rate case or any other proceeding in order to clearly show the collection and use of the funds collected under the MMC. The Commission approved PGE's 2022 MMC budget on October 20, 2022 in Order No. 22-381[3] and PGE's 2023 MMC budget on April 21, 2023, in Order No. 23-147.[4]

To continue to meet HB 2165 requirements, PGE requests reauthorization to continue to defer incremental costs and revenues associated with the MMC.

Reason for Deferral
PGE seeks to reauthorize deferred accounting treatment for costs and revenues associated with the MMC because it will minimize the frequency of rate changes and match appropriately the costs borne and benefits received by customers.

Proposed Accounting
PGE proposes the following MMC accounting treatment: the balancing account will be recorded in FERC Account 242 (Current Regulatory Liability). MMC payments (i.e., payments to support and integrate transportation electrification) will be debited to FERC Account 242 and credited to FERC Account 407.4 (Regulatory Credit). MMC amortization (i.e., revenues collected from PGE's customers via Schedule 150) will be

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[3] *In the Matter of Portland General Electric Company, Approval of 2022 Monthly Meter Charge Budget for Transportation Electrification*, Docket No. 2033, Order No. 22-381 (October 20, 2022).
[4] *In the Matter of Portland General Electric Company, Approval of 2023 Monthly Meter Charge Budget for Transportation Electrification*, Docket No. 2033, Order No. 23-147 (April 21, 2023).

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July 28, 2023
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credited to FERC Account 242 and debited to FERC Account 407.4. Interest will accrue on the balance at the approved modified blended treasury rate.

Estimate of Amounts to Be Recorded for the Next 12 Months
PGE forecasts collection of approximately $5.9 million of MMC revenues in 2023. This is consistent with PGE's approved 2023 MMC budget in Order No. 23-147.[5]

For the amount collected in 2022, PGE incurred costs of approximately $158,000 in 2022, per the Budget approved by the OPUC in Order No. 22-381. As the time of this filing, PGE expects to incur O&M costs of approximately $5,042,000 in 2023, as shown on the next page.

Monthly Meter Charge Budget and Expected Costs (in $ '000s)

Activity	Approved Budget[1]	2022 Actual	2023 Forecast
Business EV Charging Rebates	1,950	-	1,950
Residential Panel Upgrade Rebates	608	-	608
Trade Ally Network	130	-	130
Affordable Housing EV-Ready Funding	1,000	-	1,000
Municipal Charging Collaborations Pilot	500	-	500
Education and Outreach	555	106	449
TE Plan Enablement	457	52	405
Total	**5,200**	**158**	**5,042**

Information Related to Future Amortization

- <u>Earnings review</u> – While an earnings review is required, Staff does not recommend an earnings test be applied given the purposes of these expenditures.

- <u>Prudence Review</u> A prudence review will be performed when updating the amounts for amortization as part of the AAC.

- <u>Sharing</u> No sharing mechanism applies to the MMC costs or revenues.

- <u>Rate Spread/Rate Design</u> Applicable costs will be allocated to each schedule using the applicable schedule's forecasted energy on the basis of an equal percent of revenue applied on a cents-per-kWh basis, with direct access customers priced at cost of service.

5 *In the Matter of Portland General Electric Company, Approval of 2023 Monthly Meter Charge Budget for Transportation Electrification*, Docket No. 2033, Order No. 23-147, Appendix A at 5 (April 21, 2023).

- Three Percent Test The amortization of the MMC deferred costs will be subject to the three percent test in accordance with ORS 757.259(6) and (8), which limits aggregated deferral amortizations during a 12-month period to no more than three percent of the utility's gross revenues for the preceding year.

Conclusion

Approval of this deferral is consistent with HB 2165 and past Commission activities regarding transportation electrification. Staff recommends that the Commission approve PGE's application to defer costs and revenues associated with the MMC required by HB 2165.

The Company has reviewed a draft of this memo and agrees with Staff's recommendation to approve the application.

PROPOSED COMMISSION MOTION:

Approve PGE's application to defer costs and revenues associated with the Monthly Meter Charge required by HB 2165 beginning January 1, 2023, through December 31, 2023.

PGE UM 2218 Deferral of HB 2165 TE Charge Costs and Revenues

ITEM NO. CA11

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: March 22, 2022

REGULAR ____ CONSENT X EFFECTIVE DATE January 1, 2022

DATE: March9, 2022

TO: Public Utility Commission

FROM: Curtis Dlouhy and Michelle Scala

THROUGH: Bryan Conway, Marc Hellman, and Matt Muldoon **SIGNED**

SUBJECT: PORTLAND GENERAL ELECTRIC:
(Docket No. UM 2219)
PGE's Application for Deferral of Costs and Revenues Associated with the Energy Affordability Act.

STAFF RECOMMENDATION:

Approve Portland General Electric's (PGE or Company) application to defer costs and revenues to implement rate mitigation measures authorized under HB 2475(7)(1).

Require PGE to establish a separate account to track and defer incremental administrative costs associated with rate mitigation measures authorized under HB 2475(7)(1).

DISCUSSION:

Issue

Whether the Commission should approve PGE's application to defer costs and revenues associated with rate mitigation measures authorized under HB 2475(7)(1) to support PGE's recovery of these costs through an automatic adjustment clause (AAC) and balancing account.

Whether the Commission should require PGE to establish a separate account to track and defer all other costs contained in this deferral.

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Applicable Rule

PGE makes this filing in accordance with ORS 757.259, OAR 860-027-0300, and HB 2475. ORS 757.259 authorizes the Commission to allow a utility to defer, for later recovery in rates, expenses or revenues in order to minimize frequency of rate changes or to match appropriately the costs borne by and benefits received by customers. OAR 860-027-0300 sets forth several requirements for application to defer.

HB 2475(7)(1) provides that Commission may address the mitigation of energy burdens through bill reduction measures or programs that may include, but need not be limited to, demand response or weatherization.

HB 2475(7)(2) provides that the costs of tariff schedules, rates, bill credits or program discounts allowed pursuant to HB 2475(7)(1) must be collected in the rates of an electric company through charges paid by all retail electricity consumers, such that retail electricity consumers that purchase electricity from electricity service suppliers pay the same amount to address the mitigation of energy burdens as retail electricity consumers that are not served by electricity service suppliers.

Analysis

Background
On May 24, 2021, the Energy Affordability Act (HB 2475) was approved by Governor Brown. As a result of the passage of this law, the Commission is authorized to address the mitigation of energy burdens through bill reduction measures or programs that may include, but need not be limited to, demand response or weatherization. Practicably, utilities may now submit differential rates, including income-qualified discounts, to the Commission.

Under HB 2475(7)(2), the costs of tariff schedules, rates, bill credits or program discounts to mitigate energy burden must be collected in the rates of an electric company through charges paid by all retail electricity consumers, such that retail electricity consumers that purchase electricity from electricity service suppliers pay the same amount to address the mitigation of energy burdens as retail electricity consumers that are not served by electricity service suppliers.

PGE has made an advice filing utilizing the rate mitigation authority in HB 2475(7)(1). (*See* Docket No. ADV 1365, filed on January 13, 2021). If approved, the income-qualified bill discount proposed in Docket No. ADV 1365 will be effective April 15, 2022.

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Page 3

In this application to defer, PGE requests authority to defer all incremental operations and maintenance (O&M) costs and revenues associated with the implementation of HB 2475.[1] PGE explained that this deferral is to support recovery of all amounts associated with HB 2475 through an automatic adjustment clause adopted under ORS 757.210 and balancing account.

Staff held a workshop with PGE, PacifiCorp, and Citizens' Utility Board (CUB) to discuss the deferrals and proposed cost recovery on February 17, 2022. At these workshops, Staff expressed concerns with an AAC that included incremental administrative costs and wanted a means to re-evaluate the program after it has been established. PGE wanted to ensure that any spending that has been done since the effective date and before the approval of the deferral is included. CUB noted that deferring and tracking administrative costs separately gives the Commission an opportunity to review strategies used to reach out to customers and ensure that administrative costs are truly incremental and have not been previously recovered through base rates.

By the end of this workshop, all parties agreed in principle to support the following structure of PacifiCorp's and PGE's HB 2475 deferrals:

- An AAC and balancing account would be applied to the revenues collected to fund the qualified bill discounts and the costs associated with the qualified bill discounts.
- This AAC would have a sunset date to allow parties to revisit cost recovery once the programs have had time to mature.
- Incremental administrative costs would be separately deferred and tracked for later ratemaking.
- All costs would accrue interest at the modified blended treasury (MBT) rate. Parties agreed that the use of the MBT rate for the administrative costs would not be precedential for future deferrals given the interim nature of the HB 2475 rate programs.

Staff position
After reviewing both PacifiCorp's and PGE's applications to defer costs and revenues associated with HB 2475, Staff found that both applications are nearly identical in principle and should be given the same treatment. As such, Staff's position in this docket mirrors Staff's position in PacifiCorp's UM 2223 docket.

Staff shares the utilities' concerns about forecasting enrollment in the early days of these low-income bill discount programs. If a utility were to drastically underestimate enrollment, then it could be saddled with large costs that are subject to recovery under

1 Application, page 3.

HB 2475(7). Likewise, if a utility were to overestimate enrollment, it could improperly recover large sums of money from its ratepayers that would not be channeled back to any energy-burdened customers. As such, Staff will recommend Commission approval of PGE's proposed AAC with a balancing account (filed in a separate advice filing), which mitigates both of these concerns.

Staff is supportive of Oregon-regulated utilities' efforts to implement low-income rate relief programs as quickly as is responsible, but must emphasize that differential rate proposals and relief programs proposed in advance of the Staff-led, broad HB 2475 implementation effort[2] are considered interim in nature. Part of Staff's desire to highlight these programs and cost recovery proposals as interim comes from the difficulties faced in forecasting enrollment, rate collection, and administrative costs. Staff finds it appropriate to allow the utilities to recover the costs associated with rate mitigation programs, but to also provide the Commission a clear opportunity to reassess the programs and implement any improvements. As such, Staff will recommend creating a sunset date of January 1, 2024, for the AAC.[3] Although changes may not be necessary if the program is well functioning, this allows the rate-discount program to mature for over a year and gives the Commission a chance to make changes.

With respect to the administrative costs, Staff believes that these costs should be tracked separately and not be subject to the AAC or balancing account. Staff shares CUB's concern of whether these administrative costs will be truly incremental and believes that separately deferring and tracking these costs provides a better avenue to ensure that these costs are incremental in nature. Further, Staff believes that deferring and tracking incremental administrative costs allows Staff to better evaluate the lessons learned from the early days of the low-income rate programs rather than having to make the interim evaluations that would be required if it were subject to the AAC and balancing account. PacifiCorp and PGE brought up concerns that this might lead to administrative costs being excluded from recovery due to unanticipated poor program performance. Staff expressed that we expect there to be some trial and error in determining cost effective ways to reach out to energy-burdened customers and administer the programs and that our intent is not to disallow recovery of these costs in the early days of these programs.

Finally, Staff clarifies that the costs included in this deferral are only those incurred pursuant to HB 2475(7)(1), which authorizes the Commission to approve rate mitigation measures or programs.

[2] Docket No. UM 2211.
[3] An order allowing a deferral is effective for only 12 months and multi-year deferrals must be reauthorized annually. Accordingly, it is not necessary to include a sunset date for PGE's deferral authority.

Docket No. UM 2219
March 9, 2022
Page 5

Reason for Deferral
Granting this deferral will minimize the frequency of rate changes and match appropriately the costs borne by, and benefits received by, customers, in accordance with ORS 757.259(2)(e).

Proposed Accounting
In its application, PGE proposes the following treatment:

- The balancing account will be recorded in FERC Account 242 (Current Regulatory Liability).
- Income-qualified payments will be debited to Account 242 and credited to FERC Account 407.4 (Regulatory Credit).
- Revenues collected from PGE customers to support this program will be credited to FERC Account 242 and debited to FERC Account 407.4.
- Interest will accrue at the MBT rate. As previously pointed out, the use of the MBT rate on the deferred and tracked administrative costs was agreed upon by the parties and should not be viewed as precedential.

Estimate of Amounts
PGE estimates that the income-qualified energy discounts amount to be deferred will be approximately $4.2 million, with an additional $228,000 in incremental administrative costs.

Information Related to Future Amortization
- Earnings review – No earnings review is applicable due to the AAC.

- Prudence Review – A prudence review will be performed when updating the amounts for amortization as part of the AAC.

- Sharing – All prudently incurred costs are recoverable by PGE with no sharing mechanism.

- Rate Spread/Design – Costs will be allocated when updating the AAC.

- Three Percent Test (ORS 757.259(6)) – The three percent would not apply because of the AAC.

Conclusion

Based on discussions with PacifiCorp and PGE regarding the appropriate recovery mechanism for costs incurred under HB 2475(7), Staff recommends the Commission authorize PGE to defer of all costs and revenues incurred to implement rate mitigation measures implemented under HB 2475(7), subject to the following conditions:

- Incremental administrative costs will be separately deferred and tracked for later ratemaking.
- All costs would accrue interest at the modified blended treasury (MBT) rate.

PGE has reviewed this memo and agrees with its content.

PROPOSED COMMISSION MOTION:

Approve Portland General Electric's application to defer costs and revenues for rate mitigation measures implemented under HB 2475(7).

Require PGE to establish a separate account to track and defer incremental administrative costs associated with implementation of rate mitigation measures authorized by HB 2475(7).

ITEM NO. CA8

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: September 6, 2022

REGULAR ____ **CONSENT** __X__ **EFFECTIVE DATE** ____July 7, 2022____

DATE: August 23, 2022

TO: Public Utility Commission

FROM: Curtis Dlouhy

THROUGH: Bryan Conway, Caroline Moore, and Scott Gibbens **SIGNED**

SUBJECT: PORTLAND GENERAL ELECTRIC:
(Docket No. UM 2249)
PGE Deferral of Costs and Revenues Associated with Section 6 of HB 2021 and the establishment of a Utility Community Benefits and Impacts Advisory Group.

STAFF RECOMMENDATION:

Approve Portland General Electric's (PGE or Company) application to defer costs and revenues associated with Section 6 of House Bill (HB) 2021 and the establishment of a utility Community Benefit and Impacts Advisory Group (CBIAG).

DISCUSSION:

Issue

Whether the Commission should approve PGE's application to defer costs and revenues associated with Section 6 of HB 2021 and the establishment of a utility CBIAG.

Applicable Rule

PGE makes this filing in accordance with ORS 757.259, OAR 860-027-0300, and HB 2021. ORS 757.259 authorizes the Commission to allow a utility to defer, for later recovery in rates, expenses or revenues in order to minimize frequency of rate changes, or to match appropriately the costs borne by and benefits received by customers. OAR 860-027-0300 sets forth several requirements for application to defer.

Docket No. UM 2249
August 23, 2022
Page 2

HB 2021(6) requires an electric company that files a clean energy plan under Section 4 of HB 2021 to convene a CBIAG and to develop a biennial report in consultation with the CBIAG. This was codified in ORS 469A.425(3), which states:

> The commission shall establish a process for an electric company to contemporaneously recover the cost associated with the development of biennial reports and the costs of associated with compensation or reimbursement for time and travel of members of a Community Benefits and Impacts Advisory Group.

<u>Analysis</u>

Background
In July 2021, HB 2021 was approved by Governor Brown with an effective date of September 25, 2021. Section 4 of this law requires electric companies to file a clean energy plan (CEP) to the Commission and the Oregon Department of Environmental Quality. Any electric company that files a clean energy plan under section 4 of this law is also required to convene a utility CBIAG with input from stakeholders that represents the interests of customers or affected entities within the electric company's service territory.

PGE intends to establish its utility CBIAG in two phases between August and December 2022.[1] The CBIAG will be an enduring body, facilitated by a third party, that will authorize PGE on matters authorized in ORS 469A.425(2)(b). The participation and scope of the CBIAG will be refined with an advisory committee of 5-10 organizations.

Reason for Deferral
ORS 469A.425(3) calls for the contemporaneous recovery of costs associated with the CBIAG and the biennial report. Granting this deferral under ORS 757.259(2)(e) will support the use of an automatic adjustment clause (AAC) and balancing account that enable contemporaneous recovery. In turn, this will minimize the frequency of rate changes and match appropriately the costs borne, and benefits received by customers.

Proposed Accounting
In its application, PGE proposes the following treatment:

- The balancing account will be recorded in FERC Account 242 (Current Regulatory Liability).

[1] See Docket No. UM 2225 Investigation into Clean Energy Plans, Updated PGE CEP Engagement Strategy, August 4, 2022, p, 9, https://edocs.puc.state.or.us/efdocs/HAH/um2225hah165755.pdf.

- CBIAG-related costs will be debited to Account 242 and credited to FERC Account 407.4 (Regulatory Credit).

- Revenues collected from PGE customers through amortization to support the CBIAG will be credited to FERC Account 242 and debited to FERC Account 407.4.

- Interest will accrue at the MBT rate due to the low-risk nature of the AAC, as requested by PGE in its initial filing.

Estimate of Amounts
PGE is currently developing a plan for the work involving this deferral with an advisory body, including a budget of expected costs. As such, the Company is unable to provide a precise estimate at this time. However, PGE does note that expected costs could include contractor costs, compensation of advisory group participants, and *incremental* internal costs. Costs that are incurred by PGE but not incremental to those already accounted for in rates are not eligible for deferral.

Information Related to Future Amortization

- Earnings review – PGE intends to create an AAC to recover the deferred costs. If PGE does so, no earnings review would be required for the prospective rate portion of the AAC. The Commission may use an earnings review on the deferral piece; however, no earnings review is proposed by Staff given the basis of these expenditures.

- Prudence Review – A prudence review will be performed when updating the amounts for amortization as part of the AAC.

- Sharing – Staff does not intend to recommend a sharing mechanism for the deferred costs.

- Rate Spread/Design – Costs should be spread using the applicable schedule's forecasted energy on the basis of an equal percent of revenue applied on a cents-per-kWh basis, with direct access customers priced at cost of service.

- Three Percent Test (ORS 757.259(6)) – The amortization of the CBIAG deferred costs will be subject to the three percent test in accordance with ORS 757.259(6).

Conclusion

The Commission should approve PGE's application to defer costs and revenues associated with Section 6 of HB 2021 and the establishment of a utility CBIAG.

PROPOSED COMMISSION MOTION:

Approve PGE's application to defer costs and revenues associated with Section 6 of HB 2021 and the establishment of a utility CBIAG.

PGE UM 2249 Deferral of HB 2021 Utility CBIAG Costs and Revenues

ITEM NO. CA9

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: May 31, 2022

REGULAR ____ CONSENT X EFFECTIVE DATE January 1, 2022

DATE: May 16, 2022

TO: Public Utility Commission

FROM: Curtis Dlouhy

THROUGH: Bryan Conway, Caroline Moore, and Scott Gibbens **SIGNED**

SUBJECT: PACIFIC POWER:
(Docket No. UM 2224)
Application for Deferred Accounting for Costs and Revenues Associated with the Transportation Electrification Charge.

STAFF RECOMMENDATION:

Approve PacifiCorp d/b/a Pacific Power (PacifiCorp, PAC, or Company) application to defer costs and revenues associated with the Transportation Electrification (TE) Charge in House Bill (HB) 2165.

DISCUSSION:

Issue

Whether the Commission should approve PacifiCorp's application to defer costs and revenues associated with the TE Charge in HB 2165.

Applicable Rule

PacifiCorp makes this filing in accordance with ORS 757.259, OAR 860-027-0300, and HB 2165. ORS 757.259 authorizes the Commission to allow a utility to defer, for later recovery in rates, expenses or revenues in order to minimize frequency of rate changes or to match appropriately the costs borne by and benefits received by customers. OAR 860-027-0300 sets forth several requirements for application to defer.

HB 2165(2)(2) states:

> An electric company that makes sales of electricity to 25,000 or more retail electricity consumers in this state shall collect, through monthly meter charges, an amount from each retail electricity consumer served through the distribution system owned and operated by the electric company. The total amounts collected under this section must be set to one quarter of one percent of the total revenues collected by the electric company from all retail electricity consumers.

HB 2165(2)(3) states:

> Funds collected under subsection (2) of this section must be expended by the electric company to support and integrate transportation electrification and must be consistent with a budget approved by the Public Utility Commission for use of funds collected under this section. Expenditures made by an electric company pursuant to this subsection must be made on elements contained within the electric company's transportation plan accepted by the commission pursuant to ORS 757.357.

Under HB 2165(4)(3)(a), utilities are required to submit a plan that integrates the Company's TE actions to the Commission for acceptance.

<u>Analysis</u>

Background
On May 17, 2021, the Transportation Electrification Rebates and Cost Recovery (HB 2165) was passed. As a result of the passage of this law, electric companies with more than 25,000 Oregon customers are required to collect an amount from their retail customers to support TE investments. The Companies are required to submit their TE investment plans to the Commission for acceptance under HB 2165(4)(3)(a).

HB 2165(2)(2) states that the revenues used to fund these expenditures must come through monthly meter charges through the distribution system and be set at 0.25 percent of the company's revenue from retail electric customers. HB 2165 went into effect on January 1, 2022.

In accordance with HB 2165, ORS 757.259, and OAR 860-027-0300, PacifiCorp requested an order authorizing the use of a deferral to track the costs and revenues associated with the TE Charge on January 7, 2022.[1] PacifiCorp states that this deferral

[1] Application, page 2.

will support a balancing account mechanism to track the ongoing revenues brought in from the monthly meter charge and the costs incurred through TE investments.[2] The deferral will be recovered through Schedule 291 as requested in PAC Advice Filing No. 21-022, which was approved at the December 28, 2021, public meeting.

Relationship to other TE Deferrals
Staff met with the Company on April 22, 2022, to clarify this deferral, particularly how it relates to the two other PacifiCorp deferrals regarding transportation electrifications and electric vehicles in UM 1964 and UM 2200. PacifiCorp notes that it has proposed the recovery of costs associated with UM 1964 in its ongoing rate case, UE 399, and is weighing whether to fund its UM 2200 deferral with the funds brought in by the TE charge. There is nothing that requires the utility to use funds collected through the TE charge on existing programs. However, Staff suggested this as an option at the November 30, 2021 Special Public Meeting.[3]

Reason for Deferral
In its application, PacifiCorp states that granting this deferral will minimize the frequency of rate changes and match appropriately the costs and benefits received by customers.[4]

Proposed Accounting
PacifiCorp intends to record the deferred amounts to FERC Account 182.3, Other Regulatory Assets and will accrue interest at the Commission-authorized rate for deferred accounts.[5] Given that approval of this application to defer supports the use of a balancing account with an automatic adjustment clause, Staff would like to clarify that this deferral will accrue interest at the modified blended treasury (MBT) rate.

Estimate of Amounts
PacifiCorp expects that approximately $3.1 million will be collected from customers through the TE charge annually.[6] The money spent on TE programs is not known at this time, and will be approved in a separate, forthcoming docket where PacifiCorp will submit its TE budget.

Information Related to Future Amortization

- Earnings review – No earnings review is applicable due to the AAC.

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2 Application, page 3.
3 See Page 7 of Item No. RA2 Staff Report at the November 30, 2021, Special Public Meeting.
4 Application, page 3.
5 *Id.*
6 Application, page 4.

- Prudence Review – A prudence review will be performed when updating the amounts for amortization as part of the AAC.
- Sharing – All prudently incurred costs are recoverable by PacifiCorp with no sharing mechanism.
- Rate Spread/Design – Costs will be allocated to each schedule using the applicable schedule's forecasted energy on the basis of an equal percent of revenue applied on a cents-per-kWh basis.
- Three Percent Test (ORS 757.259(6)) – Future amortization will be subject to the three percent test in accordance with ORS 757.259 (7) and (8).

Conclusion

Approval of this deferral is consistent with HB 2165 and past Commission activities regarding transportation electrification. Staff recommends that the Commission approve PacifiCorp's application to defer costs and revenues associated with the TE charge in HB 2165.

PROPOSED COMMISSION MOTION:

Approve PacifiCorp's application to defer costs and revenues associated with the TE Charge in HB 2165.

ITEM NO. CA5

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: June 9, 2022

REGULAR ____ **CONSENT** __X__ **EFFECTIVE DATE** __________ **N/A** __________

DATE: May 20, 2022

TO: Public Utility Commission

FROM: Kathy Zarate

THROUGH: Bryan Conway, Marc Hellman, and Matt Muldoon **SIGNED**

SUBJECT: PACIFIC POWER:
(Docket No. UM 2221)
Application for Approval of Deferred Accounting for Operating Costs and Capital Investments Made to Implement and Operate PacifiCorp's Oregon Wildfire Protection Plan.

STAFF RECOMMENDATION:

Staff recommends the Public Utility Commission of Oregon (Commission) approve the application of PacifiCorp dba Pacific Power (PacifiCorp, PAC, or Company) for authorization to defer Accounting for Operating Costs and Capital Investments Made to Implement and Operate PacifiCorp's Oregon Wildfire Mitigation Plan (WMP), for the 12-month period beginning on January 5, 2022.[1]

DISCUSSION:

Issue

Whether the Commission should approve the Company's request for authorization to defer accounting of costs associated with Senate Bill (SB) 762 (2021).

Applicable Law

ORS 757.259 allows the Commission to authorize deferred accounting for later incorporation into rates. Specific amounts eligible for deferred accounting treatment

[1] The PacifiCorp filing uses the term Wildfire Protection Plan throughout its filing instead of WMP. The term Wildfire Mitigation Plan is used in the OPUC's OARs. For consistency with our OARs, I have replaced PacifiCorp's WPP with WMP.

Docket No. UM 2217
May 20, 2022
Page 2

with interest authorized by the Commission include, "[i]dentifiable utility expenses or revenues, the recovery or refund of which the Commission finds should be deferred in order to minimize the frequency of rate changes or the fluctuations of rate levels or to match appropriately the costs borne by and benefits received by ratepayers." ORS 757.259(2)(e).

In OAR 860-027-0300(1)(b), "Deferred Accounting" means recording the following in a balance sheet account, with Commission authorization for later reflection in rate:

(A) Electric companies, gas utilities, and steam heat utilities: current expense or revenue associated with current service, as allowed by ORS 757.259; or
(B) Large telecommunications utilities: an amount allowed by ORS 759.200.

If a deferral under ORS 757.259 or ORS 759.200 is reauthorized, the reauthorization expires 12 months from the date the authorization become effective.

In OAR 860-027-0300(3), the Commission has set the requirements for the contents of deferred accounting applications. Applications for reauthorization must include a description and explanation of the entries in the deferred account, up to the date of the application for reauthorization, as well as the reason for continuation of deferred accounting.

Notice of the application must be provided pursuant to OAR 860-027-0300(6).

Analysis

Background
On January 5, 2022, PacifiCorp requested deferred accounting to permit tracking of the operating costs incurred and prudent capital investments made to implement and operate the Company's annual WMP filed in accordance with SB 762. PacifiCorp will make a subsequent filing in 2022 for approval of a rate schedule and automatic adjustment clause to begin recovery of these costs.

SB 762 established a new state-wide requirement for public utilities that provide electric service to customers in Oregon to file an annual WMP with the first plan due by December 31, 2021. PacifiCorp filed its first WMP on December 30, 2021 (2022 WMP).[2]

Section 3(8) of SB 762[3] provides for the following:

[2] *See* Docket No. UM 2207, *In the Mater of PacifiCorp Wildfire Protection Plan*, Initial Application, Dec. 30, 2021.
[3] Section 3, chapter 592, Oregon Laws 2021, available at SB0762 (oregonlegislature.gov).

> (8) All reasonable operating costs incurred by, and prudent investments made by, a public utility to develop, implement or operate a wildfire protection plan under this section are recoverable in the rates of the public utility from all customers through a filing under ORS 757.210 to 757.220. The commission shall establish an automatic adjustment clause, as defined in ORS 757.210, or another method to allow timely recovery of the costs.

PacifiCorp is filing for deferral of the operating costs and capital investments made to implement and operate its 2022 WMP for the 12-month period beginning on January 5, 2022. PacifiCorp plans to file to establish a rate schedule and automatic adjustment clause in 2022 to begin recovering these costs in rates as allowed by SB 762.

Reason for Deferral
ORS 757.259(2)(e) allows the deferral of identifiable utility expenses in order to minimize the frequency of rate changes or the fluctuation of rate levels or to match appropriately the costs borne and benefits received by customers.

Proposed Accounting
PacifiCorp proposes to record deferred amounts to Federal Energy Regulatory Commission (FERC) Account 182.3, Other Regulatory Assets. This account will accrue interest at the Commission-authorized rate for deferred accounts.

Estimated Deferrals in Authorized Period
PacifiCorp's 2022 WMP includes incremental capital investments of approximately $24 million, and incremental operating costs of approximately $20 million are expected to be incurred in 2022.

Information Related to Future Amortization

- Earnings Review – Cost recovery associated with this deferral will not be subject to an earnings review since it would be subject to an automatic adjustment clause.
- Prudence Review – A prudence review should be performed by Commission Staff as part of their review of this deferral's annual reauthorization filing.
- Rate Spread/Rate Design – Revenues will be allocated to each cost-of-service schedule using a method to be developed prior to amortization and reflective of the transmission and generation functions expenditures incurred.
- Sharing – This deferral is not subject to a sharing mechanism.

- Three Percent Test (ORS 757.259(6)) – The three percent test measures the annual overall average effect on customer rates resulting from deferral amortizations. The three percent test limits (with exceptions) the aggregated deferral amortizations during a 12-month period to no more than three percent of the utility's gross revenues for the preceding year.

Conclusion

After Staff's review of PacifiCorp's application requesting authorization to defer, for future inclusion in customer rates, the revenue associated with cost and capital investment made to implement and operate its 2022 WMP to begin recovering these costs in rates as allowed by SB 762; and, as the application also meets the requirements of ORS 757.259 and OAR 860-027-0300, Staff recommends PacifiCorp's application be approved.

The Company has reviewed this memo and agrees with or expresses no objections to Staff's recommendation.

PROPOSED COMMISSION MOTION:

Approve PacifiCorp's application for authorization to use deferred accounting for Operating Costs and Capital Investments Made to Implement and Operate PacifiCorp's Oregon Wildfire Mitigation Plan associated with Senate Bill 762, for the 12-month period beginning on January 5, 2022.

Senate Committee on Energy

January 28, 1981
10:00 a.m.

Hearing Room B
State Capitol

Tapes 1 and 2

Members Present: Sen. Goerge Wingard, Vice Chairman
Sen. John Kitzhaber
Sen. Rod Monroe
Sen. Jan Wyers

Members Excused: Sen. Ted Hallock, Chairman
Sen. Ted Kulongoski
Sen. Tom Hartung

Staff Present: Nancy Showalter, Administrator
Connie Ohanian, Committee Assistant
Le Roy Buelt, Research Assistant

Tape 1-A The meeting was called to order at 10:10 a.m., by Senator Goerge Wingard, Vice Chairman.

Senate Bill 259

Chairman Wingard called Rep. Joyce Cohen to offer the opening statements on Senate Bill 259, explaining that Rep. Cohen served as Chairperson to the Energy Policy Review Committee and this bill was introduced by that committee.

010 Rep. Cohen gave an historical perspective on the bill, and noted that Senate Bill 259 is further direction to the PUC in Oregon to move ahead to adopt rate structures that provide for maximum energy conservation, and to reward conservation efforts, thus providing a positive incentive to conserve.

Senator Wyers said that this bill, as he understands it, does not make any specific requirement of what is in a rate order.

Rep. Cohen agreed and further stated that she would like to have some more work in the area of who is causing, and who should pay for the highest amount of new energy growth.

127 Senator Wyers asked if Rep. Cohen could share with the committee how the Energy Policy Review Committee defined "conserve" in their deliberations. He said that we all know what "conserve" means in a residential setting, but he wondered what "conserve" means in terms of an industrial consumer.

Rep. Cohen said that had been a sore point with some of their members for a long time in that they tend to impose the conservation burden on residential customers because it is not so "technical" nor so "individualistic." Therefore, they have been asking the Department of Energy for justification of where they get their 4.5% growth projections in the industrial-commercial sector and they have not received the answers.

She noted that that was one of the questions that would have to be considered by this committee and it was one of the areas where they had not progressed -- in the area of commercial-industrial growth -- and that is where the major growth is projected, she said.

She said she had not been given any indication from the Department of Energy exactly how they arrived at that figure. It's a vague assumption, she said.

Senator Wyers asked if Rep. Cohen thought it would be an appropriate role for the PUC to be concerned with the economic stability of the State in terms of our industrial-commercial sector to be able to continue to compete by being energy efficient. He wondered if that was not giving the wrong job to the PUC in expecting them to look after the economic health of the State by encouring the industrial-commercial sector to modernize in the conservation.

Rep. Cohen said she thought one of the reasons we have not had energy conservation in the past is because people have been given the wrong signals. We have not given proper economic signals to people in the way of rate-setting. For a long time, we didn't charge people the marginal costs of the new energy and we have in the past, given breaks to large users on the basis of cost of service and we have been reluctant to move in to examine the cost of production of a large block of energy beyond that of cost of service. She said we need to build in the cost of producing new energy as well when those rates are set.

198 Alberta Heffron, attorney, appearing on behalf of Oregon Fair Share, said they were pleased by the introduction of Senate Bill 259. She noted that Oregon lags far behind its sister states of Washington, Montana, Idaho and California in implementing innovative electric and natural gas rates designed to reward conservation.

Ms. Heffron noted that Fair Share has been working for several years to win adoption of lifeline rates, which, she said, are a proven method of electric and natural gas rate design that promote and reward conservation. This committee will soon be asked to consider a lifeline conservation rate bill that is being co-sponsored by Fair Share and the Oregon AFL-CIO. She urged the committee to give favorable consideration to both Senate Bill 259 and the lifeline conservation rate bill.

215 Wilma Nicholis, also a member of Fair Share, said she thought it was becoming painfully evident that residential and small business consumers of electricity and natural gas as paying more and more this year for the same or lesser amounts of energy than they did a year ago. She said there was a real need for a rate-paying system that rewards conserving and they are looking to the Legislature to enact a law that embodies the lifeline concept -- a bill that would provide direction to the PUC to faithfully administer that law.

Senator Wingard asked Ms. Heffron if she was inclined to favor a bill that was probably broader and more general in scope such as this measure, or would she prefer to have something more specific.

Ms. Heffron answered by saying that they would be promoting their lifeline bill which will be more specific than the statement of policy embodied in Senate Bill 259. She would suggest that questions be postponed until the time of that hearing.

386 Steve Rapp, Oregon Community Action Programs, noting that there are 12 programs statewide, serving the energy needs of around 330,000 low income Oregonians, stated that they are helping people in two areas: that of helping people with fuel bills to help meet the crunch of rising energy costs, and weatherizing of low-income houses.

He said he agrees with the concept of Senate Bill 259, but had some disagreement with the particulars. He said he believes that electric rates should send a very clear economic message -- a convincing economic message -- to consumers. The rates do not today do that.

Tape 2-A Mr. Rapp maintained that this bill was a bit too vague and asked the questions: (1) what is "conservation" rate? is it a lifeline rate? (2) was there a conflict in the statutes? (3) and what is "equitable?" He said he could not support this bill without knowing what is "equitable."

020 Senator Wyers said he did not see this bill as having any teeth in it and Mr. Rapp indicated he agreed.

105 Senate Bill 264

Senator Wingard presented opening statements on Senate Bill 264, noting that it was proposed by Nancie Fadely, and that it would allow a travel allowance for bicycles.

SB 39, 259, 282, 826, Transition Team
and Alumax, SB 111.

Tapes 1 and 2

Senate Committee on Energy

April 1, 1981
10:00 a.m.

Hearing Room B
State Capitol

Members Present: Senator Ted Hallock, Chairman
Senator George Wingard, Vice Chairman
Senator Tom Hartung
Senator John Kitzhaber
Senator Rod Monroe
Senator Jan Wyers

Members Excused: Senator Ted Kulongoski

Staff Present: Nancy Showalter, Committee Administrator
Connie Ohanian, Committee Assistant
Le Roy Buelt, Research Assistant

Witnesses: Fred Van Natta, Oregon State Homebuilders
Walter Friday, Building Codes Division, Department of Commerce
Katy Murphy, Legislative Research Office

Tape 1-A Chairman Ted Hallock called the meeting to order at 10:10 a.m.

Senate Bill 259

030 Fred Van Natta, representing the Oregon State Homebuilders, appeared to testify on Senate Bill 259. He voiced some concern with the language and suggested that if it was the committee's intent to move forward on the bill, he would like to present a suggested amendment that would prohibit the Commissioner from discriminating against new hook-ups.

Chairman Hallock noted that there was intense sentiment on the committee to move forward on the bill and said that he as Chairman was especially interested in the legislation. He asked Mr. Van Natta how he read the language now as potentially prohibiting new hook-ups.

Mr. Van Natta read from the bill: "...carrying out duties, functions and powers regarding the establishment of rates charged by public utilities for services furnished to customers, the commissioner shall adopt rate structures that will provide for maximum energy conservation...."

"Maximum energy conservation," Mr. Van Natta said, would be a prohibition on new hook-ups.

Mr. Van Natta, at the request of Senator Hallock, agreed to present the committee with his suggested amendment.

Senate Bill 826

100) Mr. Walter Friday, Building Codes Division of the Department of Commerce, testified on Senate Bill 826 and presented a statement for the record as well as a copy of the Structural Specialty Code and Fire and Life Safety Code, Chapter 53, which is the segment of the State Building Code which regulates energy conservation (see Exhibit A of these minutes).

158) Senator Wingard said he had some amendments to Senate Bill 826 and he suggested holding the bill for a while and make some contacts with Ways and Means and with the Governor's office.

SB 282 - Transition Team

222) Chairman Hallock reported that the Transition Team met yesterday and one agenda item was the consideration of hiring the executive director, the team wanted to consider this in closed session, and asked if there was objection. Don Bundy of the Oregonian objected, Ed Sheets said then that he had made luncheon reservations for the team and that the meeting would break from 11:30 to 2 p.m. Bundy of the Oregonian asked if he could go to the lunch and Sheets said "no." Le Roy Hemmingway, to his perpetual credit, said that he would not be going to the lunch, he then joined Bundy, Common Cause, and others for lunch -- their own lunch.

Chairman Hallock said he was really proud of him and he hopes that will continue. He said he was just appalled at the arrogance of the transition team continuing to attempt to do its business in private.

Alumax bill

235) Chairman Hallock said he was also appalled at Associated Oregon Industries and their reaction to the Alumax issue.

He said he thought his definition was consistent with the bill. In regulating the investor owned utilities, he said, there are a couple of very major issues. The first one is the question of how much revenue is that utility entitled to. SB 427 does not in any way affect that determination.

The second major issue in regulation is who is going to pay that revenue requirement. In Oregon, traditionally, one looked at who was responsible for creation of certain kinds of costs and then you spread the revenue requirement to the customer class based upon that cost determination.

A few years ago, Mr. Lobdell said, a new theory of spreading that revenue requirement was adopted and it was called "long range incremental costing." What that attemps to do is to look at the cost growth of the utility, project it into the future, and allocate the revenue requirement based upon who is contributing to the cost growth rather than imbedded costs.

Mr. Lobdell noted that low income and fixed income Oregonians tend to dominate the class of customers using electric resistance space heating. There was some opinion that he was loading that (cost) up on the fixed income people and the economically disadvantaged in a far greater proportion than the other customers in that class. That lead to his turning down "lifeline" under those conditions, even though he had found that it would achieve conservation.

170) Chairman Hallock said he did not know if Mr. Lobdell had read SB 259 and he read a portion of it. "...carrying out duties and functions and power regarding the establishment of rates charged by public utilities for services furnished to customers, the Commissioner shall adopt rate structures that will provide for maximum energy conservation while reflecting and rewarding customer conservation efforts and that will provide a positive incentive to conserve...." If that bill was passed right now and signed into law, Senator Hallock asked, would Mr. Lobdell implement a "lifeline" concept under it?

Mr. Lobdell answered "no, not as a result of the legislation," he said, he would move in that direction but he would not snap into place a "lifeline" bill. He said he intends to look at the question of "lifeline" in the context of the "regional bill," and if it does in fact provide us an opportunity for rate reductions, that's the time to start looking at "lifeline" rates.

Chairman Hallock said he had one final question and that was that the witnesses from the senior organizations alleged that there was some "hanky panky" and that Mr. Lobdell and met with Lee Johnson and that Mr. Johnson had told Mr. Lobdell to enter that order. Did any of those things take place, he wanted to know. Are any of those allegations true?

Mr. Lobdell said, "no, absolutely not."

Bob Castagna, representing Oregon Environmental Council, spoke in support of the bill.

George Starr was signed up to testify but was not present at the time his name was called.

Blanche Schroeder from the Portland Chamber of Commerce had presented testimony at an earlier time and for purposes of the record, her statment is include as an exhibit to these minutes (see Exhibit E).

Because they were alluded to in this hearing, copies of a letter to John Lobdell from Senator Hallock and reply to Senator Hallock from Mr. Lobdell and a memo from Gene Maudlin to John Lobdell are also included as exhibits and are identified here as Exhibits F, G and H, respectively.

The hearing ended on SB 427 .

Senator Hallock then voted to amend Senate Bill 259 to add a new section saying that all ratemaking procedures with the Public Utility Commissioner will be open to the public and will be conducted in public hearings. The motion carried unanimously on roll call vote with all members present and voting "aye" except Seantor Monroe who was not present.

The meeting was adjourned at 12:05 p.m.

Respectfully submitted,

C. Ohanian

Connie Ohanian
Committee Assistant

Tape 1-A, 0 to 485
2-A, 0 to 485
1-B, 0 to 485
2-B, 0 to 485
3-A, 0 to 075

Senate Committee on Energy

April 20, 1981
9:30 a.m.

Hearing Room B
State Capitol Bldg.

Members Present: Senator Ted Hallock, Chairman
Senator George Wingard, Vice Chairman
Senator Tom Hartung
Senator John Kitzhaber
Senator Ted Kulongoski (10:15)
Senator Rod Monroe
Senator Jan Wyers

Staff Present: Nancy Showalter, Committee Administrator
Connie Ohanian, Committee Assistant
Le Roy Buelt, Research Assistant

Witnesses: Fred Van Natta, Oregon State Homebuilders
Gene Maudlin, Public Utility Commissioner's office
John Lobdell, Public Utility Commissioner
Austin Collins, Ratepayers Union and Grey Pathers
Chuck Wilson, Legislative Counsel

Tape 1-A

Chairman Ted Hallock called the meeting to order at 9:35 a.m. and opened the work session.

Senator George Wingard explained the amendment to SB 256 and talked briefly about set-back thermostats. He then moved the amendments be adopted. He explained that the intent is to take heat pumps and dehumidifiers out of the bill. After brief discussion, the amendments were adopted without opposition. Senator Wingard then moved the bill out do pass with amendments and that motion carried on roll call vote with all members present and voting "aye," except Senator Kulongoski who was not present.

Senator George Wingard was assigned to carry the bill.

Chairman Hallock noted that there were proposed amendments to SB 259. Fred Van Natta, representing the Oregon State Homebuilders Association, recalled for the committee that he had proposed an amendment in an attempt to develop language that would prevent the Public Utility Commissioner from either prohibiting the use of electric space heating, or to require exhorbitant rates for new hook-ups. Mr. Van Natta's proposal was identified as SB 259-1 amendments from Legislative Counsel.

Two other amendments were considered at this time and they were identified as Legislative Counsel amendments 259-2 and 259-3 (see Exhibits attached to these minutes for all three proposed amendments).

Senator Monroe asked Mr. Van Natta if his concern was that the PUC Commissioner might use the rate schedule to sort of replace what this committee banned in SB 39. Mr. Van Natta asnwered that was part of it but it doesn't necessarily have to limit itself just to SB 39. Senator Monroe said he understood that but asked if it was Mr. Van Natta's concern that the PUC might use that rate schedule to do what he did in his earlier order which was ultimately suspended.

Mr. Van Natta said that was correct.

Ms. Nancy Showalter, Committee Administrator then explained the other two amendments which had been drafted by Chuck Wilson of Legislative Counsel. She also called attention to a memo from the Public Utility Commissioner's office dated April 14, 1981. Mr. Lobdell had asked his counsel, John H. Socolofsky, if he saw any problems in placing the procedures under the Administrative Procedures Act. The memo clearly states that Mr. Socolofsky didn't see any problems in doing so. (see Exhibit F of these minutes).

145) Chairman Hallock asked if Mr. Gene Maudlin wished to comment on either of these amendments. Mr. Maudlin said he did not.

Senator Hartung moved that SB 259 be removed from the table. There was no objection and it was so ordered.

Chairman Hallock then moved adoption of amendments to SB 259, identified as SB 259-2 and that motion carried on roll call vote (all members present and voting "aye" except Senator Kulongoski who was not present).

NOTE: After further discussion, it was decided to have Legislative Counsel draw up a different set of amendments and the committee then moved to rescind their previous action on adoption of amendments. That motion also carried without opposition and Chuck Wilson was directed to draft new amendments.

John Lobdell, Public Utilities Commissioner, testified briefly and answered questions from committee members about the amendments.

220) In response to a question from Senator Wyers, Mr. Lobdell said he did not see a need for further constraining the authority of his office. There was discussion also about how people would interpret the word "rate" and whether it is actually a "tariff" and whether it should be identified as such.

257) In response to questions from committee, Mr. Van Natta replied that given the explanation and the difference between the use of the term "rate" and "tariff," it is probably appropriate to add "tariff" after the word "rate," so they would be proscribed from both charging a different rate and a hook-up charge.

Mr. Lobdell said he would respond now to the amendment and he said he thought it was not only unnecessary but from a public policy viewpoint, it was very unwise. He said if SB 39 does not become a part of the law, and he has to continue to deal with the problem of potential shortfalls and the priority use of electricity and the wisdom of using electricity for electric resistance heating, it would again be necessary to address that issue and with this amendment, the legislature would have effectively constrained his ability to do so.

350) Chuck Wilson, Legislative Counsel, responded to questions by committee and was directed to re-draft an amendment to SB 259.

Tape 2-A

Austin Collins, representing theRatepayers Union and the Oregon Grey Panthers, testified in favor of SB 427.

Ms. Showalter explained the proposed amendments to SB 427, identified as Legislative Counsel Amendments SB 427-1. There was a motion to adopt the amendment and there was no opposition and it was so ordered (see Exhibit G of these minutes for copy of amendment).

NOTE: A letter recevied by Committee staff from K. T. Shipley and dated April 3, 1981 was entered into the record (see Exhibit H).

NOTE: A letter to Senator Hallock from Gene Maudlin, Deputy PUC Commissioner, and dated April 20, 1981 is also shown here as Exhibit I.

Senator Kulongoski then moved SB 427 as amended to the floor with a do pass recommendation. That motion carried with Senators Kitzhaber, Kulongoski, Monroe and Wyers voting "aye," and Senators Hallock and Hartung voting "no." Senator Wingard was not present.

Senator Hallock noted that he and Senator Hartung intended to file a minority report on SB 427 and he gave his views on the reasons for this intended action.

Mr. Bauer said he thought there might need to be some clarification of what a "manufacturing plant" is. Senator Wingard asked Mr. Bauer if he would like to bring in an amendment to speak to that concern. Mr. Bauer said he would be happy to do that.

Senate Bill 259

Senator Wingard noted that there was a proposed amendment to SB 259 identified as 259-4 from Legislative Counsel.

Nancy Showalter explained that this amendment was at the request of the committee at the last hearing and it would limit the changes we are making to the ratemaking proceedings so that we don't touch other sections of the Public Utility Commissioner's reponsibilities.

Gene Maudlin, Deputy Public Utility Commissioner, said he had reviewed the amendment and found it to be appropriate.

Vote was then taken on the proposed amendment and that motion carried with Senators Hartung, Kitzhaber, Monroe and Wingard voting "aye," and the other members not present.

Vote was then taken on a motion to send the bill out with a do pass with amendments recommendation and that motion also carried with the same Senators voting "aye."

Senate Bill 427

Senator Monroe said he was concerned about SB 427 because somehow the language "reasonably well weatherized" was still left in the bill and he said it was his understanding that the Public Utility Commissioner had commented that the bill was directed only at those homes that were "reasonably well weatherized."

That was not the intent, Senator Monroe explained, and there needed to be an amendment to make that clear (See Exhibit A for the proposed amendment which had been suggested by Oregon Fair Share).

Senator Monroe moved that the committee reconsider the vote by which they passed SB 427 to the floor. That motion carried with Senators Hartung, Kitzhaber, Monroe and Wingard voting "aye," and the other members not present.

Senator Monroe then moved the amendments dated April 21 with the Oregon Fair Share label on the top (see Exhibit A) and while they were waiting to vote on that motion, Senator Hartung brought up another question and noted that one of his concerns with the bill was the "small business" lifeline rate.

Legislative Records in the Oregon State Archives pertaining to:
1987 HB 2145 Relating to: public utilities.

HOUSE ENVIRONMENT AND ENERGY COMMITTEE MINUTES:

March 11: p. 3-4
Also on audio tape: 57, side A; 56, side B

March 25: p. 3-6
Also on audio tape: 71, side B; 72, side B; 73, sides A-B; 74, side A

March 30: p. 4-5
Also on audio tape: 75, side B

April 8: p. 13-16
Also on audio tape: 96, sides A-B; 97, side A

Separate exhibit file contains 60 pages.

SENATE BUSINESS, HOUSING AND FINANCE COMMITTEE MINUTES:

May 21: p. 11-13
Also on audio tape: 99, side B; 100, side B

June 9 (1 pm): p. 6-8
Also on audio tape: 122, side B; 123, side B; 124, side

June 11: p. 9
Also on audio tape: 126, side B; 127, side A

Separate exhibit file contains 57 pages.

Total Pages of Minutes:	19
Total Pages of Exhibits:	117
Total Pages Combined:	**136**

Compiled by Gary Halvorson, Reference Archivist, December 31, 1997 answer, and REP. JOHNSON felt it was important to know that before moving it into the bill.

398 REP. ANDERSON suggested deleting Sections 5, 6 and 7. Committee concurred. Mr. Wang said it was acceptable because that is the current procedure.

406 REP. PARKINSON asked if the money collected would go into the general fund and REP. CEASE said that was correct.

MOTION: REP. BARILLA moved LC 2129-2 to the bill.

VOTE: There being no objection, motion carried with all members present.

421 REP. CEASE asked Mr. Wang is he wished elimination of Section 8 and 9. Mr. Wang said that was correct.

MOTION: REP. PETERSON moved LC-2129-3 to the printed bill.

VOTE: There being no objection, motion carried unanimously with all members present.

MOTION REP. ANDERSON moved deletion of Section 10 of the bill (LC-2129-7).

VOTE: There being no objection, motion carried with all members present.

HC 87 E&E TAPE 57 SIDE A

REP. CEASE asked if there were any objection to leaving the emergency clause in. There being no objection, emergency clause will stand. REP. CEASE asked that LC be asked to correct Section numbers so that a final version is available for Friday meeting, if possible.

020 REP. BARILLA expressed congratulations to Legislative Counsel and Committee Administrator for their handling of this difficult bill.

028 REP. CEASE said the bill will be hand engrossed before coming back to the committee. REP. JOHNSON felt a printed engrossed was needed. REP. SOWA said it was not possible to get a printed engrossed version until the committee passes it out. REP. JOHNSON was asked to carry the bill.

REP. CEASE closed the work session on HB 2129.

Public Hearing HB 2145

062 Charles Davis, PUC Commissioner testified on HB 2145 (Exhibit A) urging adoption of the bill.

204 REP. CEASE asked if this goes beyond what is currently being done, or authorizing you to do what you have been doing. Mr. Davis said it does not go beyond what is currently being done.

263 REP. EACHUS asked for examples of PUC needing statutory authority. Mr. Davis asked his staff to respond. Ray Lambeth stated that deferrals have been used in instances relating to several items. REP. EACHUS asked for major items. Mr. Lambeth said power plants coming into service. REP. EACHUS asked for specifics and Mr. Lambeth said Coal Strips 3 and 4. REP. EACHUS asked what PUC did in those cases. Mr. Lambeth said they delayed the rate increases associated with putting those plants into service until a subsequent time. At time the rate change was made, the accumulated defferal was amortized. REP. EACHUS asked if there were instances where PUC did this with a reduction in the utilities cost. Mr. Lambeth responded yes and elaborated.

REP. EACHUS asked if PUC would consider Coal Strip 3 or 4 an unanticipated event. Mr. Lambeth said they had rate hearings on Coal Strip 3 so the decision had been made that the plant belonged in rates. As a matter of administrative convenience the rate change was deferred. REP. EACHUS asked what about Coal Strip 4 and Mr. Bill Warren said no and explained that Coal Strip 4 was anticipated. REP. EACHUS asked, other than governmental decisions, what else would you consider an unanticipated event. Mr. Warren explained. REP. EACHUS asked if reductions in expenses were ever deferred. Mr. Warren said they were. REP. EACHUS asked if PUC considered changes in the basis upon which the utility filed its data and Mr. Warren said they had never deferred anything of that nature because it is part of the general rate review.

395 REP. BARILLA voiced concerns with definition of unanticipated event. Are we talking about accidents, catastrophes, etc.? How do you define it? Mr. Warren said he does not believe "unanticipated event" is used in the legislation. It is used here illustratively. REP. BARILLA felt a better word could be used.

HC 87 E&E TAPE 56 SIDE B

REP. BARILLA continued.

016 REP. PARKINSON asked if a big franchise payment would be covered by this and Mr. Warren said it would have little effect on a utilities operation and that PUC would not act on it.

025 REP. SOWA asked if anyone has investigated to see if you have been in violation of the law. Mr. Socolofsky responded that he had said there was substantial doubt about their authority to include in future rates, costs which the utilities have incurred in the past. It was a retroactive rate practice which the law prohibited. PUC was told if they wanted to continue the practice, it had to be expressly authorized by the legislature. REP. SOWA asked if these types of actions have resulted in ballot measures. Mr. Socolofsky responded.

062 REP. EACHUS asked for comparisons of changes in capital that would not be significant. Mr. Warren clarified what he had intended. REP. EACHUS asked for more information which Mr. Warren provided.

REP. CEASE closed the hearing on HB 2145 at 3:00 p.m. Hearing will be rescheduled.

HC 87 E&E TAPE 71 SIDE B

261 REP. CEASE explained that the video tape will relate to timber issues that will come before the committee.

Public Hearing HB 2145

290 Dan Meek testified in opposition of HB 2145 on behalf of the Utility Reform Project and Forelaws on Board (Exhibit C).

339 REP. PARKINSON asked if Mr. Meek's charts were based on actual figures and Mr. Meek said they were theoretical.

393 REP. BARILLA asked for explanation of Chart 1 of the Exhibit. Mr. Meek explained. REP. BARILLA asked if the solid line represented Coal Strip 4 for the rate period and Mr. Meek said that was correct.

HC 87 E&E TAPE 72 SIDE B

020 REP. ANDERSON said he understood that the 1986 tax act was a tax shift of $120 billion dollars from business and asked for an explanation of why utilities are a different type of business and why they will make a profit out of it rather than be hit by their share of the $126 billion dollars. Mr. Meek said the tax rate has gone down and the fact that the rate has reduced has put them in a lower tax rate. The fact that the rate has decreased reduces on the utility's books deferred taxes.

038 REP. JOHNSON asked what role Mr. Meek was playing in this testimony. Mr. Meek responded that he was receiving no compensation but after experiencing the utility rate process he is extremely discouraged about what is happening and believes that rate payers have been treated very unfairly over the past several years and is concerned that they not be treated unfairly in the present or future. Deferred revenue accounts are used in a one sided way. REP. JOHNSON asked if Mr. Meek had a personal bad experience with the utility company and Mr. Meek said he had not. REP. JOHNSON asked what had caused Mr. Meek to appear before the committee with this approach and Mr. Meek said it was frustration.

070 REP. BARILLA talked about his experience in attending public utility hearings and the efforts being made by various groups for utility reform.

160 REP. PARKINSON asked if PUC had questioned Mr. Meek's resale figures. Mr. Meek said the PUC staff presents little or no testimony and has undertaken no cross examination. Mr. Meek explained the process of settlement conferences conducted by PUC.

200 REP. BARILLA said since there are several versions of HB 2145 he wished to know which version Mr. Meek was following. Mr. Meek said he was using the one provided by PUC and REP. CEASE said that the Committee also has the same bill. REP. CEASE asked Mr. Meek to give the committee the citation and Mr. Meek complied.

291 REP. ANDERSON asked for explanation of situation of capital costs rising and less power being sold to California and Mr. Meek said that is the reason that rate increase requests are filed so frequently.

340 REP. PARKINSON asked if the proposal by Mr. Meek would have to be done on a monthly basis and Mr. Meek said he did not think that would be necessary. REP. PARKINSON asked if cost of sales would be deducted first and Mr. Meek said that was correct. REP. PARKINSON asked if rates would change three or four times a year for the customer. Mr. Meek said a balancing account could be credited for the benefit of the customer and adjusted yearly.

422 REP. ANDERSON asked for explanation of cost of operation for a coal fired plant built on a cost of roughly 7 cents per KWH and how it could operate at 1 1/2 cents per KWH because they want to sell it to California at 2 cents. Mr. Meek explained.

467 REP. CEASE asked if it were Mr. Meek's opinion that this bill had no merit and Mr. Meek said he did not think the bill was necessary and PUC is able to operate with existing authority.

485 REP. PARKINSON asked Mr. Meek if cost of service adjustment was the same as automatic adjustment clause to which Mr. Meek referred. Mr. Meek said he was not sure what the attorney general was referring to.

HC 87 E&E TAPE 73 SIDE A

010 REP. PETERSON asked if there were other states who operated in the way Mr. Meek suggested. Mr. Meek said he was unable to respond to that at this time.

030 Charles Davis, PUC Commissioner, reviewed his previous appearance before the committee. He said his interest is in communicating the decisions the commissioner has made in the past and the result of those decisions in terms of what we face now. Mr. Davis felt it was important to go through the detail of what is presently in the deferred account for all of the utilities. He stated that he disagreed with Mr. Meek's views of the way the PUC is regulated.

060 Bill Warren, PUC, introduced Ray Lambeth and Jack Socolofsky. Mr. Warren wished the committee to note that an accounting of deferred accounts was in the material provided to the committee by PUC. He also addressed questions raised by Mr. Meek

087 REP. EACHUS said that in considering this bill and other legislation he wanted to receive information on automatic adjustment clauses, interim rate adjustments and requests from an intervenor other than the staff or utility. Would also like to try and confirm whether one day after the rate case order was issued, they came in and asked for a deferred account on Coal Strip 4. Mr. Warren said that was not correct and gave more details.REP. EACHUS asked that a chronology be provided on the PP&L case and Mr. Warren said he would do that. REP. EACHUS asked if by applying for a deferred account when they did PP&L avoided a revisiting of their rates. Mr. Warren explained what was considered and the deferrals used. REP. BARILLA asked if there were currently no deferred revenue accounts for Coal Strip 4 in the PP&L rates and Mr. Warren said they are amortizing costs for Dec-April 1986. REP. BARILLA said the Attorney General has said that it is and Mr. Warren agreed.

210 REP. BARILLA asked Mr. Socolofsky if he wrote the AG opinion and Mr. Socolofsky said he did not but he was familiar with it.

230 REP. PARKINSON asked PUC to provide a glossary of the terms used by them.

240 REP. EACHUS said the AG opinion referred to the balancing account and he does not understand fully at this point. Mr. Socolofsky said that the opinion says balancing accounts are not allowed without express legislative authority and the automatic adjustment clauses that are authorized by statute can only be of the type that does not have a balancing account in it. Therefore, if it is desired to use an automatic adjustment clause with a balancing mechanism additional legislative authority would be necessary.

265 John Lobdell representing Northwest Natural Gas Co. testified in support of passage of HB 2145 and offered proposed amendments (Exibit D). He explained the company's handling of conditions based on falling oil prices. The amendment submitted by PUC commissioner does not deal with balancing accounts tied to the revenue side of utility regulation. The amendments Northwest Natural Gas offers addresses this issue. They ask that they not be put in triple jeopardy so have proposed amendment that would except those cases that were subjected to a final order of the commissioner under statute and had been concluded. There should be assurance that amortization of deferred balances do not impact in any one year a customer's bill, but believe that cap should relate only to amounts placed in balancing accounts under Subsection 2c. Northwest Natural Gas thinks the legislation is essential and their amendments are reasonable and they support the Commissioner's bill in all other respects.

417 REP. PARKINSON asked Mr. Lobdell if he is primarily concerned with last year where they had a contested case, an agreement was reached by all parties, then you say a stipulated agreement and unless relief is given here you will be out for last year. Mr. Lobdell said that unless legislation is passed the Commissioner is under an obligation to follow the advice of the attorney general and take whatever action is necessary to terminate those accounts that are on the books of the utilities.

450 REP. PARKINSON asked if CUB agreed to this and Mr. Lobdell said CUB was represented by counsel and they were a party to the stipulation. REP. PARKINSON asked if the group that Mr. Meek represents were intervenors and Mr. Lobdell said Mr. Meek represents a different group.

460 REP. JOHNSON asked what Northwest Natural Gas stakes were and Mr. Lobdell said about $7 million dollars.

467 REP EACHUS asked PUC representatives to answer questions about their proposed amendments.

HC 87 E&E TAPE 74 SIDE A

001 Mr. Socolofsky explained Subsection 2C and Subsection 5 and the amendments proposed by Northwest Natural Gas Co.

050 REP. ANDERSON asked how the review would be handled and Mr. Socolofsky explained the procedure. Mr. Lobdell added to Mr. Socolofsky's explanation. Mr. Socolofsky reviewed Subsection 6 as it applies to amortization.

120 REP. EACHUS asked if the deferred accounts were usually created by rate cases or proceedings outside of rate changes. Mr. Socolofsky said there were some in each category.

135 REP. ANDERSON wished to get a feeling from PUC on the impact of language difference on 6. Mr. Lobdell said that language in 6 is better but they have no major disagreements with PUC on that.

153 REP. CEASE asked if other witnesses wishing to testify on HB 2145 would be available to testify on Monday. REP. CEASE asked those who could not return on Monday to present their testimony.

178 Richard Jarrett, representing CP National, testified in favor of HB 2145 from the perspective of his company stating that he feels that balancing accounts are a rate making tool which solves administrative problem of frequent rate changes and provides the best mechanism to match revenues and costs and stabilizes rates for consumers. Balancing accounts are used only when it makes sense to use them. Adjustments go both ways-up and down. Currently CP National has several balancing accounts in existance.

242 REP. CEASE asked if this bill did not pass, what would be the impact on CP National. Mr. Jarrett said it would be disastrous and gave examples.

270 REP. EACHUS asked how the co-generation costs were established and who determined them and Mr. Jarrett responded.

280 John Gould, counsel for CP National added information to REP. EACHUS' question. REP. EACHUS asked questions regarding several aspects of CP National's situation and Mr. Jarrett and Mr. Gould responded.

440 REP. JOHNSON asked if "staff" meant PUC staff and Mr. Jarrett said that was correct.

450 REP. EACHUS asked if CP National has objections to the provisions for review and Mr. Jarrett said they could support the numbers and would provide it.

HC 87 E&E TAPE 73 SIDE B

REP. CEASE closed the hearing on HB 2145.

Work Session HB 2919

REP. CEASE reviewed the proposed amendments to HB 2199 for the Committee.

050 REP. PICKARD spoke on the issue of HB 2199 and the reasons for the amendments proposed.

100 REP. CEASE asked if the aggregate amount would be excluded and REP. PICKARD said that was correct and that was supported by Jim Curl owner of Bend Aggregate.

030 REP. ANDERSON asked if Mr. Bauer had reviewed the PP&L proposal. Mr. Bauer said he had only seen the proposed amendments just prior to the meeting and believes that REP. ANDERSON's interpretation is correct.

044 Dave Willis testified on HB 3168 giving his views of the current situation. Mr. Willis said they need the protection of state regulations because they are an unincorporated area. Mr. Willis said he supported HB 3168 and hoped the committee would too.

070 REP. GILMAN asked Mr. Willis if he felt that no more power lines should be built in Oregon and Mr. Willis responded that careful consideration should be given to production of power.

REP. CEASE closed the hearing on HB 3168 and asked REP. PETERSON to meet with parties involved.

Public Hearing HB 2145

100 Roy Hemingway, Boise Cascade representative, testified in support of HB 2145 PUC amendments. Boise Cascade's concern derives from situation Boise is facing in eastern Oregon with its mills in the service territory of CP National Corp. That Corporation was allowed by commissioner Maudlin to accumulate costs from deferred cogeneration purchases in a deferred account beginning February 1986. Those costs accrued in that account through November, 1986 when Commissioner Maudlin allowed those costs to be put into rates in addition to adding a rate increase which resulted in a large percentage increase to Boise Cascade. Amounts were forecastable but they chose instead to accumulate those amounts in a deferred account. Boise Cascade supports a limitation on deferred accounting and the staff amendment is an appropriate limitation. The amendment says that deferred accounting is permissable but when those deferred accounts get so large that they ought to be amortized in rates they should be amortized so that rate impact is reasonable.

160 REP. PARKINSON asked if the deferred amount was a temporary measure. Mr. Hemingway said it was up to the commissioner to decide how long the amortization could accrue.

175 REP. EACHUS said he was bothered that the committee did not have clear definition until decisions were imposed by another agency of the federal government and felt clear conditions of when deferred accounting should be allowed were needed. REP. EACHUS asked Mr. Hemingway what criteria PUC should be guided by in deciding of whether an item should be deferred. Mr. Hemingway said whether it is an extraordinary expense, whether it is one that would be a temporary charge only and the fact that costs are relatively small and vary quickly over time would be good criteria. REP. EACHUS asked if extraordinary referred to size, and Mr. Hemingway said he was not.

210 REP. ANDERSON asked if most of this was caused by a PURPA mandate and Mr. Hemingway said that Public Utility Regulatory Policies Act PUC mandated that the utility buy this power. REP. ANDERSON said DEQ orders for scrubbers, etc. would also fall under this bill. Mr. Hemingway said that was his understanding.

235 Bill Warren, PUC representative, introduced Ray Lambeth and Jack Kosolosky. Mr. Warren furnished information requested by the committee at an earlier hearing (Exhibit F) and reviewed the items with the committee.

325 REP. EACHUS asked questions relative to the chronology and Mr. Warren responded with information in Exhibit F. REP. EACHUS asked when the last rate order on PP&L was. Mr. Warren responded July, 1985. REP. EACHUS asked if there was not rate change from July, 1985 until January, 1987 and Mr. Warren said that was correct.

370 REP. PARKINSON asked for the percentage of increase and Mr. Warren responded 1.3%.

380 REP. CEASE asked if proposed amendment LC 2145-2 was still current. Mr. Warren explained and said they would also support the change listed in his letter.

400 REP. EACHUS wished additional explanation in the chart in Exhibit F and Mr. Warren responded. Mr. Lambeth added to the explanation.

417 REP. CEASE said the number 1 amendment received by the committee could be discarded. Number 2 and Number 3 are still under consideration. REP. EACHUS will work on resolution of current differences.

REP. CEASE closed the hearing on HB 2145

Public Hearing HB 2144

450 Richard Bird, manager of Environment & Energy for Oregon Steel Mills testified in favor of HB 2144 (Exhibit G)

HC 87 E&E TAPE 76 SIDE B

Mr. Bird continued his testimony.

110 REP. EACHUS asked on what basis the Commission had the authority. Mike Dodden said existing authority is clear under the attachment to Mr. Bird's testimony. REP. EACHUS asked if Mr. Dodden had looked at the memorandum referred to from the assistant AG and Mr. Dodden said they did. REP. EACHUS asked what his assessment of its discussion of discriminatory rates. Mr. Dodden replied that if you have a classification that is otherwise lawful you do not have discriminatory rates. REP. EACHUS felt the memorandum concluded that allowing an individual company to barter, bargain, threaten or negotiate was going to lead the system into creating a situation of discrimination. Mr. Dodden said the first opinion was disturbing and the second opinion was clearer. REP. EACHUS said he was bothered that the amendments said that any time price or service competition exists you can set up an individual class of one customer. Under those conditions any industrial customer could meet the criteria and become a classification of one. REP. EACHUS asked for an explanation of the contract with Bonneville Power and Mr. Dodden explained the situation. REP. EACHUS asked if they would have received cheaper power if they went with Bonneville. Mr. Dodden said that was correct. REP. EACHUS asked if there were other similar steel mills served by PGE. Mr. Dodden said there are three steel mills that have special rates but only one plate mill.

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REP. PETERSON concluded her review and asked Tom Donaca to present the amendment added today concerning small scale activity. REP. CEASE asked Mr. Donaca to read the new proposed amendment.

035 REP. PARKINSON felt water lines should also be added. Mr. Donaca felt that might be appropriate. Phil Ralston said present bill language seemed to cover this.

050 REP. ANDERSON offered other language and Mr. Donaca expressed the opinion that a problem could be created.

060 REP. JOHNSON felt size of committee should be reduced.

070 REP. CEASE asked for some language that would be satisfactory. Mr. Donaca offered the proposed language and REP. CEASE read it to the committee. REP. PETERSON felt that too much specificity might cause more harm and REP. CEASE agreed. REP. BARILLA felt he would be comfortable if REP. CEASE or REP. PETERSON made a statement of intent. REP. PETERSON said the legislative intent is to include any utility. REP. CEASE referred to APD OSHA regulations and affirmed that the legislative intent is to include any and all utilities. REP. CEASE referred the committee to REP. JOHNSON's concern with the size of the board. Phil Ralston listed the need for those members on the Asbestos Advisory Board. REP. JOHNSON withdrew his concern. REP. ANDERSON said he would be more comfortable with the use of "shall" rather than "may". Phil Ralston said the potential problem was that if federal regulations change in the future there could be a problem. REP. BARILLA asked if sublevel is defined and would it be appropriate, time notwithstanding, that both sublevels receive the same certification, licensing, and training requirements.

166 REP. CEASE said it was the intent to recognize that there are different levels of need and training will be different. REP. PETERSON concurred. REP. CEASE asked committee to go with "shall". Mr. Donaca suggested use of chair rather than chairman.

MOTION: REP. PETERSON moved HB 2367-22 as amended to Ways and Means with a do pass recommendation.

VOTE: On a roll call vote, motion passed unanimously with all members present.

REP. CEASE closed the hearing on HB 2367.

Work Session HB 2145

249 REP. CEASE asked REP. EACHUS to tell the committee which document to use for this work session. REP. EACHUS said the hand engrossed version of HB 2145 dated 4/8/87 and explained the reason for the latest amendments. He feels all concerns have been addressed by the amendments. REP. EACHUS asked PUC representatives to go through the amendments specifically.

315 REP. SOWA asked if the problem of CP National was incorporated into the amendments and REP. EACHUS said they have a unique situation and they were not

able to deal with that. REP. BARILLA said this bill was for unanticipated events and he asked for clarification.

339 John Socolofsky, PUC representative, said the unanticipated event on Mr. Davis' chart was for illustrative purposes.

351 REP. PARKINSON asked if it would be appropriate to have the bill explained as it relates to the CP National situation.

380 Bob Warren, PUC representative, explained the significant aspects of the bill as it now stands. An emergency clause has been added, the hand engrossed version the committee has allows commission to recognize retroactively costs imposed by another governmental agency over which the utility had no control. Before action can be taken, steps are specified, allowing utility customers or commissioner through his staff to move costs pertinent to the act and be included in a deferred account balances. It allows a variety of items to be included in deferred account balances for reasons of regulatory policy, allows commission to authorize interest, but does not require it, requires commission to review utility's earnings position when it applies for amortization of the deferrals, and includes a grandfathering provision so that existing deferred balances can be collected.

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Mr. Warren continued his explanation of the amendments and said PUC is comfortable with the hand engrossed version.

009 REP. CEASE said committee had been disturbed by past activities of the PUC and asked REP. EACHUS if some of the problems are corrected with this legislation. REP. EACHUS felt that was correct. Key provisions allow commission to staff themselves on their own motion to request deferral of some amounts for later in rates and it is possible rate payer representatives could request a deferral of benefits. Those benefits could be accrued by the rate payers and deferred at the same time. There is now balance in the process. He said he is less worried under new commission set up. This balances it out. We need to recognize there are instances where deferrals are necessary and you do not want a rate case on smaller items. The balancing type of account can benefit rate payers and that was important.

057 REP. BARILLA asked if REP. EACHUS ran this by Dan Meek and REP. EACHUS said he had been unable to do so. This may be a better approach than the amendments submitted by Mr. Meek. REP. BARILLA asked if LC amendments LC 2145-4 have been moved. REP. CEASE said they had not and he wished to hold that item.

080 REP. EACHUS asked the PUC to explain what the current situation is and referred to Dan Meek's testimony. Mr. Socolofsky said interim increases are something a utility is entitled to by statute if commission allows and costs justify an increase of some kind.

130 Richard Jarrett, Vice President CP National, offered testimony on HB 2145, (Exhibit I).

195 REP. PARKINSON asked if date of November 26, 1986 was the date used by the Attorney General and Mr. Jarrett said it was coincidental. Mr. Jarrett went

into a detailed explanation of CP National's problem and said the solution is available to the committee.

238 REP. PARKINSON asked if CP National's amendment were put in the bill, would their rate only be able to go up 3%.

244 REP. BARILLA said his initial point about what the initial representation by the PUC commissioner about this bill taking care of unanticipated risk and events has bothered him and he appreciated REP. EACHUS clarifying the points. He said he does not want to see this mechanism being used to try to cure any and all events. We can justify anything under this bill if we want to and the relief under this bill should be very narrowly construed.

262 REP. JOHNSON said he would be inclined to go in the other direction.

272 Mr. Jarrett said this is a one time fix. REP. CEASE asked PUC to respond to this matter.

279 There was an extensive dialogue between PUC staff and members of the committee regarding the situation of CP National.

393 REP. BARILLA said there has been an assertion that stockholders will have to absorb costs and he asked if there is another way to write off that amount. Mr. Warren said CPN had entered into a verbal agreement.

413 Mr. Jarrett interrupted the response of Mr. Warren.

443 REP. BARILLA insisted that his question be answered and thought it was inappropriate for CPN to interrupt.

453 Mr. Warren explained CPN's financial situation stating that if the costs are incurred by the company and are not recognized in rates, costs are borne by customers.

470 Discussion continued.

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004 Committee members continued to question PUC representatives on matters of deferred costs.

060 Roy Hemingway, Boise Cascade, explained their connection with CP National and stated that Boise Cascade had no knowledge of this amendment. He expressed concern and said CP National is asking the legislature to substitute its judgment for PUC decision. Mr. Hemingway urged committee's rejection of this amendment and passage of this bill.

MOTION: REP. EACHUS moved that HB 2145, hand engrossed, be sent to the floor with a do pass recommendation 2145-4.

MOTION: REP. PARKINSON moved that the C P National amendments be moved to the bill in a substitute amendment.

REP. EACHUS urged committee members to oppose the substitute amendment and gave his reasons.

REP. PARKINSON asked if CP National can come back later or not.

Mr. Warren they could not.

REP. BARILLA asked if there were any distinction between fixed and variable costs.

REP. PARKINSON asked if C P National could ask for reconsideration of deferred accounts from PUC.

Mr. Warren said no further deferred accounting can be done. C P National can petition for refief.

171 REP. EACHUS moved the previous question. REP. CEASE asked for more time.

> **VOTE:** REP. PARKINSON'S substitute motion failed on a roll call vote with REP. ANDERSON, GILMAN, JOHNSON, PARKINSON voting Aye and REPRESENTATIVES BARILLA, EACHUS, PETERSON, SOWA, CEASE voting No.

> **VOTE:** Motion passed with REPRESENTATIVES BARILLA, EACHUS, GILMAN, PARKINSON, PETERSON, SOWA, CEASE voting Aye. REPRESENTATIVE JOHNSON voting No.

REP. JOHNSON served notice of a minority report.

REP. EACHUS will carry the bill.

REP. CEASE closed the work session on HB 2145

Public Hearing HB 2144

245 Mary Ann Hutton, representing Northwest Industrial Gas Users, testified on HB 2144 (Exhibit J).

312 Rod Schmall, Smurfit Newsprint Corporation testified on HB 2144 (Exhibit K).

REP. EACHUS asked for clarification and Mr. Schmall complied.

409 REP. EACHUS asked Mr. Schmall if Smurfit has the capability of reducing its load? Mr. Schmall replied and explained. REP. EACHUS said his concern was that Smurfit's rates and usage can affect the average cost. Mr. Schmall said that could be true.

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REP. EACHUS questioned how price of newsprint factored in. Mr. Schmall said a sliding scale makes sure that rate payers aren't giving up advantages to benefit Smurfit. REP. EACHUS said he was not sure wording of bill would cover the situation.

048 Bill Warren, PUC, added information.

BEFORE THE HOUSE COMMITTEE
ON ENVIRONMENT AND ENERGY

HOUSE BILL 2145

Testimony of Charles Davis
Oregon Public Utility Commissioner March 11, 1987

To explain the reasons for this legislation, it is first necessary to describe some principles used in setting utility rates.

Utility rates are set for the future. All rates now in effect are based on expectations of utility company expense for this period. Those expectations were based on facts presented at the time the Commissioner set rates. As with any forecast, those expectations of the future can never be exactly correct. Whether or not a utility has net earnings during the time today's rates are in effect, the utility cannot ask for an increase in rates to make up past losses or improve past earnings.

If in looking to the future the utility expects its present rates will not cover its expenses and provide a reasonable rate of return for its investors, it may apply to the Commissioner for authorization to increase its rates. In doing so, its proof of need is based on its future expectations.

There are a few circumstances in which expenses unanticipated at the time rates were approved by the Commissioner would have been included in rates had the Commissioner known of them. These often are the result of governmental action. In part, that's what HB 2145 seeks to address. For example, the Oregon Legislature mandated certain weatherization programs. Since the expense of these programs to the utilities could not be predicted accurately, the Public Utility Commissioner authorized the companies to accumulate those costs for a time before rates were increased to recover them.

Similarly, the Nuclear Regulatory Commission has on prior occasions reduced the cost to Portland General Electric for processing spent fuel from Trojan. PGE, therefore, had collected more from its customers, for this purpose, than it would need. The management of PGE did not achieve these savings by superior management. The company realized the savings as the result of governmental action.

In all these instances, it is not a question of whether the changes in revenue or in expense resulting from government action will be included in rates charged for service, it is a question of when that should begin. It would be almost impossible to conduct a utility rate review each time these mandated changes occur. Hence, it has seemed reasonable to defer consideration of these governmentally imposed reductions or increases in expense to the next formal review of all expenses to be incurred by the utility in providing service.

There is a rule of law that utility rates may not be made retroactively in absence of express statutory authority. This rule prohibits a utility from recovering past costs in future rates and prohibits a regulator from taking a utility's past profits, lawfully earned.

From the customer's viewpoint, the principle underlying the prohibition against retroactive ratemaking is that the customer should know what a utility service costs him at the time he takes it. The posted tariff on the day of service represents a contract between the customer and the utility. The customer should not expect to pay more and the utility should not expect to get less. To the extent past costs are reflected in future rates or past utility profits are taken away in future rates, they benefit or burden future purchasers of the service (not necessarily the same ones who caused the cost) and compromise this principle.

This measure is designed to allow the Commission to make rates retroactively in certain situations. Generally speaking, it allows the Commission to include in rates those costs which have been imposed retroactively upon a utility by another governmental agency and which the utility therefore had no opportunity to predict in a rate proceeding. In such case, the utility could not have increased its rates in anticipation of the retroactive levy.

Secondly, the proposed measure allows the Commission to make rates retroactively in cases where the utility asks that a cost be deferred and not reflected in rates until a later date, either because (a) the full extent of the costs, that is, the net cost, will not be known until a future time, or (b) a rate change, otherwise authorized, should be postponed.

In both of these situations, if the amounts in question, whether they represent costs retroactively imposed on the utility, or those deferred at its request, are later amortized in rates, the rates are said to be made retroactively because they reflect recovery of a cost already incurred by the utility, as opposed to one which is expected in the future. However, the Commissioner believes that there are instances in which retroactively made rates may be in the public interest and this measure gives the Commission authority to act accordingly.

The Attorney General's Office has advised the Public Utility Commissioner that current statutes do not allow the deferral of ratemaking to accommodate many of these mandated and unanticipated changes in expense between formal rate proceedings.

Although I have asked the Attorney General for a formal opinion on this matter, my judgment is that the practice of deferred recognition for some kinds of transactions is appropriate. Your approval of HB 2145 would make explicit the Commission's authorization to follow this practice. My staff has discussed HB 2145 with all known interested parties, including representatives of regulated utilities, industrial customers, and consumer groups. The modification offered today results in part from those discussions as well as from continuing review by the Attorney General's office. This does not imply that a consensus was reached on this bill, as you may learn from other parties here today.

The bill specifies the circumstances under which deferred expense items may be allowed. The provisions of the bill are permissive, not mandatory. The PUC may authorize deferrals, but is not required to. Public notice is required. The Commission will assess the reasonableness of deferral by requesting public comment before the deferral is allowed. (Sec. 2(2)) The only exception to the notice requirement is where a governmental body imposes amounts retroactively.

All parties and ratepayers are protected by the requirement that general rate case procedures be used before rates are changed to include deferred amounts. (Sec. 2(4)) Those procedures include notice to all parties, filing of evidence by the utility, and hearings if requested. Section 2(4) also requires a review of the utility's earnings at the time of application. The earnings review will allow the Commission to determine whether amortization of deferred income or expense amounts is warranted based on the utility's earnings; if earnings are higher than authorized, expense amortization through rates will not be appropriate.

An additional safeguard is provided by Section 2(3). To encourage timely action by utilities, deferrals may begin no earlier than the date of application. If an increased expense level begins in January, but an application is not made until July, the January through June increases in costs must be absorbed by the company.

Some examples of the types of situations covered by the bill may be useful. I will present them in the order in which they appear in the bill.

Sec. 2(1)(a) Amounts lawfully imposed retroactively by order of another governmental agency.

Retroactive tax increases would be covered by this provision. Although not common, there have been occasions when this has occurred. In recent years there have been special property tax assessments, and the Federal Tax Reform Act of 1986 disallowed use of most investment tax credits retroactive to the first of the year. If these amounts are material, recovery in rates could be permitted.

Sec. 2(2)(a) Amounts incurred by a utility resulting from changes in the wholesale price of natural gas or electricity approved by the Federal Energy Regulatory Commission.

The FERC has responsibility for setting wholesale natural gas and electricity rates. Particularly for gas distribution companies, these costs may be quite significant. This subsection would allow deferral if necessary to match up both refunds and cost increases with the timing of a general rate change or to coordinate with other income or expense changes.

Sec. 2(2)(b) Balances resulting from administration of Section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act of 1980 (Regional Act).

The Regional Act established a mechanism through which residential and certain other customers of investor-owned electric utilities (IOU's) were to get benefits associated with the federal hydroelectricity system. The Bonneville Power Administration (BPA) administers the process. IOU's file with the BPA on behalf of eligible customers and pass the benefits on through regular billings. The BPA has frequently adjusted the amounts payable to IOU's. The PUC has authorized a deferral mechanism to assure that ratepayers get the appropriate benefit as finally settled. This subsection would authorize continued use of this "true-up" procedure.

Sec. 2(2)(c) Amounts incurred by a utility which the Commission finds should be deferred in order to minimize the frequency of rate changes, or the fluctuation of rate levels, or to match the costs borne by and benefits received by ratepayers.

This subsection covers the many occasions when a legitimate ratemaking income or expense item is changing and the PUC believes rates should be adjusted as a result, but finds that rate changes should take place at some subsequent time.

For example, expense reductions might occur in the second quarter of a year, but it is known at the time that an expense increase, perhaps a wholesale rate change, will occur in the fourth quarter of the year. To avoid a rate decrease followed in short order by a rate increase, it may be preferable to accumulate the expense decreases and use them to offset, in whole or in part, the subsequent expense increase.

We currently have an example of such a situation. The Tax Reform Act of 1986 reduces Pacific Power & Light Company's federal income tax charges for 1987. Rates could be reduced early in 1987 for this change. But the BPA has filed notice of an expected rate increase effective October 1, 1987. It could be appropriate to defer and accumulate certain of the benefits arising from the tax expense decreases, with interest, and use them to offset BPA-related cost increases.

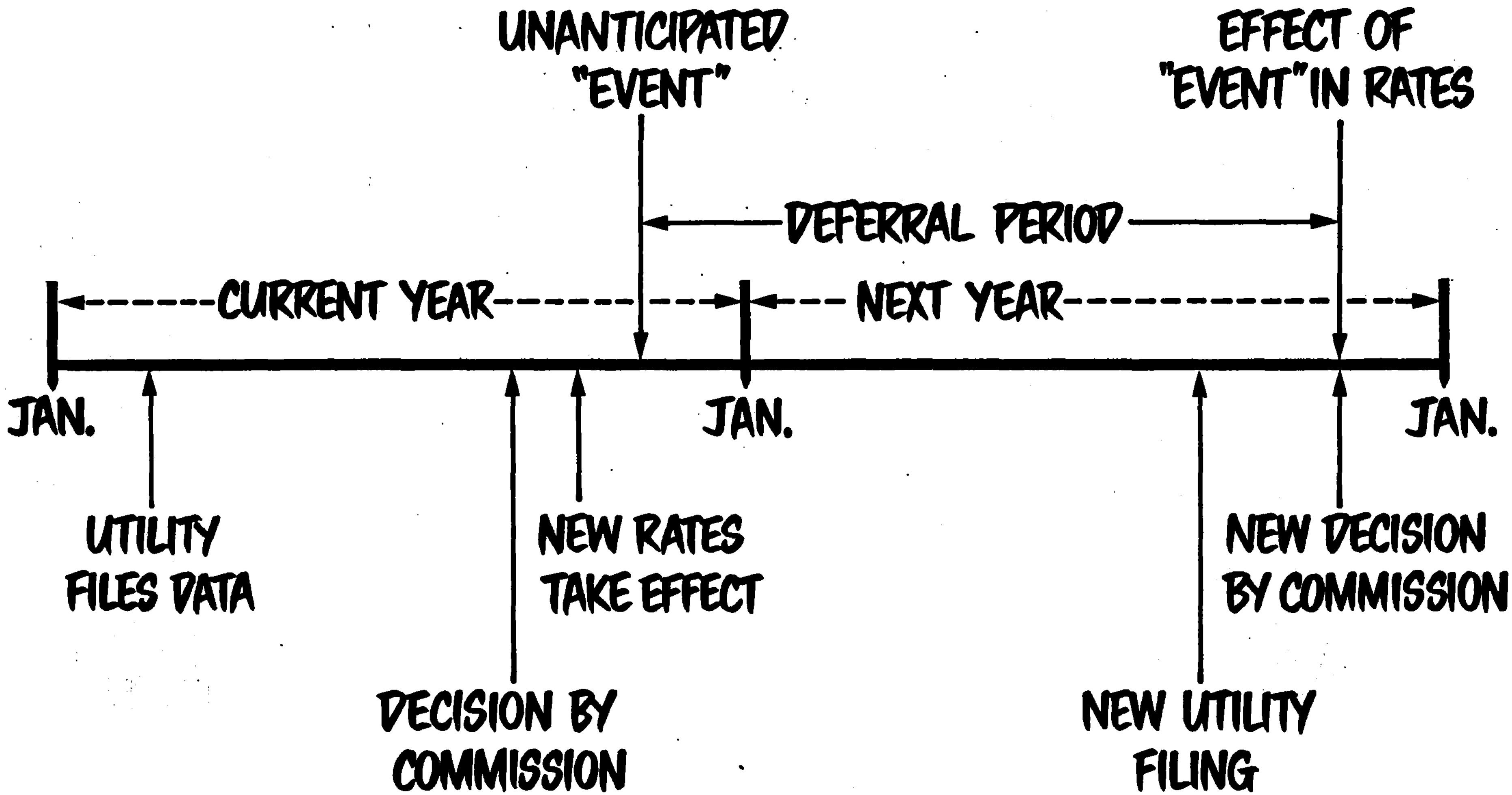
The subsection also refers to permitting deferrals to match costs and benefits. Considerations of this type led to spreading costs of weatherization programs over a ten-year period. The reasoning was that weatherization measures would produce benefits lasting for some time. It seemed inappropriate to charge costs only to ratepayers at the time the weatherization expenses were incurred.

Section 2(5) provides authorization for completion of amortizations begun, continued deferral of amounts already existing, and continued use of accounts authorized as of the effective date of the bill. To the extent rate action has not already been ordered, however, we intend to apply the procedures embodied in Section 2(4).

This legislation would clarify the authority of the Commission to use deferred accounting when it is deemed by the Commission to be in the public interest to do so.

I urge your adoption of HB 2145.

Jack Socolofsky from the Attorney General's office and Bill Warren from my staff are here to assist in answering questions you may have.


UNANTICIPATED "EVENT"
EFFECT OF "EVENT" IN RATES
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CURRENT YEAR
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UTILITY FILES DATA
NEW RATES TAKE EFFECT
NEW DECISION BY COMMISSION
DECISION BY COMMISSION
NEW UTILITY FILING

TESTIMONY ON H.B. 2145

by

DAN MEEK

on behalf of

Utility Reform Project and Forelaws on Board

before the

Committee on Environment and Energy
Oregon House of Representatives

Ron Cease, Chair

March 11, 1987

H.B. 2145 attempts to legitimize a procedure already used by the Oregon Public Utility Commissioner to allow private utilities to charge higher rates whenever any item of cost rises but to deny attempts by ratepayer advocates to reduce utility rates when items of cost decline. It would transform into legislatively-endorsed state policy the Commissioner's refusal to protect Oregon residents and businesses from unreasonable utility rates.

The practice in other states is to allow utilities to seek rate adjustments when their overall costs have risen such that their existing rates fail to afford an opportunity to earn a reasonable return on investment. The public utility commissions in other states do not allow utilities to raise their rates simply because <u>one</u> item of cost has risen, regardless of offsetting changes in the utility's overall costs. For example, a commission would not allow Utility X a rate increase simply because its cost of expensive power has increased, if in the meantime the utility's cost of capital has declined to offset the increased power purchase expense.

In H.B. 2145, the Commissioner seeks authority to do exactly that--allow utilities to raise rates simply because <u>one</u> item of cost has risen, regardless of other, downward changes in the utility's overall costs since the conclusion of its most recent rate proceeding. For example, in 1986 both Portland General Electric Co. (PGE) and Pacific Power & Light Co. (PP&L) sought the Commissioner's permission to establish "deferred revenue" accounts for Colstrip 4 so that they could "bank" the additional cost of Colstrip 4 as soon as it came on line and then charge this extra cost to ratepayers later, whether or not their overall cost of providing service had actually increased. The

Commissioner granted their requests, allowing them to "accrue deferred revenue" equal to the capital and operating cost of Colstrip 4, regardless of the fact that many of their other costs had decreased since their most recent Oregon rate proceedings.

In response to the PGE and PP&L strategy of justifying higher rates on the basis of one item of higher cost, the Utility Reform Project in August and September 1986 asked the Commissioner to establish "deferred debit" accounts for PGE and PP&L and to accrue there the difference between (1) the utility's monthly revenue from retail ratepayers and (2) the revenue that would have been collected, had their rates been recalculated at an the cost of capital actually being experienced as measured by the utility's own suggested methods.[1] We suggested that this difference be booked on a monthly basis until the Commissioner issued his final order in the proceeding, which would then amortize the amount booked in this account to the credit of ratepayers (as an offset to the company's revenue requirement) over a reasonable period of time--treatment precisely parallel to that the Commissioner granted to PGE and PP&L for their Colstrip 4 costs.

PGE and PP&L did not dispute that their actual cost of common equity capital had dramatically declined since the issuance of their most recent Oregon rate orders, from about 15% to 12%. Instead, they argued that our proposal would not properly account for all factors affecting their return on investment. According to PP&L:

> Expenses would not be considered, revenues and expenses would not be normalized for temperature or stream flow, extraordinary items would not be adjusted, and other months of the year would not be used to develop average data.

The Commissioner, of course, agreed with PP&L, stating:

> Because rates are set prospectively, the determination of appropriate rate levels requires examination of a full test year and normalization of test year revenues and expenses to properly reflect conditions expected to occur when rates will be in effect.

OPUC Order No. 86-1085, October 24, 1986. Yet scrutiny of all test year revenues and expenses is precisely not what the

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1. We could have similarly requested deferred debit accounts for the difference between the revenue generated by PP&L's projected test year loads and actual loads or between its projected and actual resale revenues. The principle is the same. It was error for the Commissioner to establish the Colstrip 4 deferred revenue account requested by PP&L and then to refuse to establish the similar cost-of-capital deferred debit account sought by URP.

Commissioner required to justify adoption of the PGE and PP&L "deferred revenue" accounts for Colstrip 4.

In essence, the utilities contend that, whenever they can identify additional costs, such costs should be recognized, charged to deferred revenue, and later collected from ratepayers. But when we have identified reduced costs, they argue that such cost reductions cannot be viewed in isolation. This is the grotesque double standard the Commissioner has adopted to date and which H.B. 2145 would sanctify.[2] And H.B. 2145 itself would not apply only prospectively but would retroactively bless the Commissioner's unauthorized actions in allowing the utilities to establish "deferred revenue" accounts for Colstrip 4 and to charge those costs to ratepayers.

H.B. 2145 would authorize the Commissioner to violate two fundamental principles of utility ratemaking:

1. Rates should be based on the cost of providing present service to the customer, not on the cost of providing present service to the customer <u>plus</u> the cost of providing past service which the utility failed to collect.

2. Regulators should not allow utilities to "selectively update" their rate filings to reflect only costs which have increased, but not those which have decreased, since their most recent rate orders.

It would also purport to allow the Commissioner to ignore ORS 757.355, enacted by the voters in 1978, which forbids utilities from charging ratepayers tomorrow for costs properly allocable to yesterday.

<u>Cost of Providing Past Service</u>

The reason PGE and PP&L sought to "defer" revenue for the cost of Colstrip 4 during early 1986 and to charge these costs to ratepayers later during 1986 and 1987 (in addition to the cost of Colstrip 4 properly allocable to late 1986 and 1987) was because they could not justify a rate increase in early 1986 based upon all the changes to their costs since their most recent Oregon rate orders.

For example, on March 24, 1986, the Commissioner in OPUC proceeding UE-39 issued OPUC Order No. 86-276, approving a $23.8 million annual rate increase for PP&L which actually took effect on July 1, 1985. PP&L filed its application to accrue deferred revenue for Colstrip 4 on March 25, 1986--one day after this order was filed. PP&L did not seek recovery of Colstrip 4 costs

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2. We note that H.B. 2145 would authorize the Commissioner to establish deferred accounts only "upon application of a utility," not upon application by ratepayers--another double standard.

in UE-39, even though the company knew that the plant would begin commercial operation in April 1986. Instead, PP&L waited until the Commissioner had approved the UE-39 rates, then filed application for an additional rate increase based on its asserted costs of Colstrip 4. PP&L did not ask that the Colstrip 4 rate hike be implemented immediately but that the revenue that would have been collected through an immediate rate increase be "deferred," accumulated in a "deferred asset account," and be charged to ratepayers later. Nor did PP&L request that the Commissioner examine other changes to its cost and revenue situation since the close of the record in the UE-39 proceeding on November 7, 1985.

Ratepayers should not be required to pay costs unrelated to the period during which the rates are in effect. Allowing PP&L to accumulate "deferred revenues" during Period A and to collect such revenues from ratepayers later during Period B violated this basic ratemaking tenet, often called "retroactive ratemaking." The issue is not whether the rates apply to past or future consumption; it is whether future consumption is burdened by costs properly allocable to past periods. Here, the operation, maintenance, depreciation, and return on investment for Colstrip 4 during early 1986 properly applied to that period and that period alone.

In Re Southern California Edison Co., 64 PUR 4th 452 (CA PUC 1984), the California Public Utilities Commission (CPUC) held that the accumulation of deferred revenue for the period after initial commercial operation of the San Onofre 2 (SONGS 2) nuclear project but before the Commission had authorized rates to include the cost of the plan "constituted unlawful retroactive ratemaking." 64 PUR 4th at 455. The CPUC had earlier allowed the utility to establish a "deferred debit account" and to deposit there "depreciation expense from the in-service date for accounting purposes to the date rates are fixed." 64 PUR 4th at 457. The Commission later ruled that the utility had to cease accrual of AFUDC "when the plant begins commercial operation" (August 18, 1983) but could not use the Commission's accounting order to "preserve" revenue requirement for later transfer to ratepayers.

> We recognize that the utilities will not recover all of their costs for the period from August 18th to October 8th, because of the bar on retroactive ratemaking. Because rates designed to recover reasonable noninvestment-related costs for SONGS 2 were not effective until October 8th, any of these costs incurred before October 8th cannot be included in the utilities' recoveries. Similarly, depreciation expense incurred before September 7th will not be recovered, although for reserve purposes depreciation commenced on August 18th. Also, because of the unusual timing of events, the utilities will not recover a return on their investment in SONGS 2 from August 18th to September 7th.

64 PUR 4th at 463-64.

In Philadelphia Electric Co. v. Pennsylvania Public Utility Commission, 502 A2d 722 (PA 1985) "PECO v. Pennsylvania PUC"), the court upheld the Pennsylvania PUC's decision to disallow recovery of $41.4 million of depreciation and operating expense for the utility's new $285 million of pollution control equipment for two of its coal-fired power plants. When the equipment began functioning in December 1982, the utility sought and received an "order approving PECO's proposed deferred accounting of the approximately $3.5 million per month in operating and depreciation expenses associated with the pollution control facilities." 502 A.2d at 725. In 1983, the utility proposed to amortize the $41.4 million balance of these of accumulated expenses to ratepayers over a 3-year period. The Commission denied the application. In upholding the Commission, the court concluded:

> Simply put, these pollution control facilities' expenses were not, for whatever reason, anticipated by the utility nor made the subject of evidence before the Commission in this previous rate case and the question presented by PECO's claim for deferred expenses in the instant proceeding is whether a utility may properly found a claim for increased prospective rates on past expense items which were greater than anticipated by the utility's proofs supporting the customer charges in effect.

502 A2d at 727.

In Kentucky Utilities Co. v. FERC, 760 F2d 1321 (D.C. Cir. 1985), the court upheld FERC's decision to disallow recovery of carrying charges for a new coal-fired power plant for the period subsequent to its initial service date but prior to the effective date of the new rates. Kentucky Utilities Co. (KU) on May 31, 1981, placed into service its $250 million 500 MW Ghent 3 coal-fired plant. In March 1981, KU had submitted to FERC a schedule of revised rates reflecting the cost of the plant and requested an effective date of June 1. FERC suspended the proposed rates for 5 months, allowing the new rates to take effect in November 1981. In July 1982, KU then filed revised rates to include $1.6 million of AFUDC accrued during the June-November 1981 period. FERC rejected the proposal and was affirmed by the court, which stated:

> If the FPC somehow failed to make this rule clear in Chelan and Safe Harbor, the Supreme Court subsequently explained, more broadly, that an inability to obtain a return on investment through operating revenues does not provide justification for capitalizing the loss for inclusion in a later rate base. See FPC v. Natural Gas Pipeline Co., 315 U.S. 575, 590, 62 S.Ct 736, 745, 86 L.Ed. 1037 (1942). . .

> . . . The fundamental principle that there can be no capitalization of carrying charges incurred on funds used during construction once construction has ceased is simply too well established to merit extensive elaboration.

760 F2d at 1325. Further, the court concluded:

> In the context of suspension-period carrying charges, the Commission had already determined that the utility and its investors should bear the risk that the decision regarding when to file a rate increase will not always result in a coincidence between the plant's in-service date and the date the rates reflecting the new plant become effective.

760 F2d at 1328.

Selective Updating

H.B. 21245 would also allow improper selective updating of utility rates. In his rate orders, the Commissioner is presumed to have examined all factors relevant to the appropriate level of rates during the period that those rates are in effect. It would be highly improper to then allow the utility to update only one of those factors--the added cost of Colstrip 4, for example--without concurrently accounting for changes in the other factors, such as the cost of capital, load growth, and revenue from power sales to other utilities.

In Tariff Filing of New England Telephone & Telegraph Co., 488 A2d 746 (Vt. 1984), the court examined the Vermont Public Service Board's order allowing the phone company (NET) a $3.3 million rate increase based entirely upon changes in depreciation rates and policies, without examining other changes since the conclusion of the utility's previous general rate case.

> This Court on two recent occasions has held that establishing utility rates by selectively updating one cost factor alone without assessing other cost or revenue factors in an improper or forbidden procedure. In Re Central Vermont Public Service Corp., supra, 144 Vt. at 49, 473 A2d at 1162; In re Green Mountain Power Corp., 142 Vt. 373, 384, 455 A2d 823, 827 (1983). In the present case, a similar approach has been taken; NET has been allowed to make an adjustment in its rates to the public based solely on a change in its depreciation rates and policies without an analysis of other important rate-making factors, such as rate of return, rate base, and operating revenues and expenses.

488 A2d at 748. The court agreed with the Vermont Department of Public Service that the Board had engaged in unlawful "selective updating" of NET's revenue requirements and stayed the rate increase. Subsequently, the court found the rate hike to be "a

clear case of selective updating; it must therefore be reversed. Tariff Filing of New England Telephone & Telegraph Co., 505 A2d 680, 682 (Vt. 1986).

Selective updating is unfair to ratepayers and results in rates which are unreasonable. Until the Commissioner approves new rates for a utility at the conclusion of a rate proceeding, the reasonable rates are those determined by the order. If the utility both charges those rates and concurrently accumulates deferred revenue for Colstrip 4, then its collections from ratepayers during that period will exceed the reasonable level.

Violation of Ballot Measure 9 of 1978

In 1978, Oregon voters by a 2-1 margin enacted ORS 757.355, which forbids utilities from charging rates which include the cost of any real or personal property "not presently used for providing utility service to the customer." The utilities concede that this statute outlaws CWIP ("construction work in progress"), the practice of charging today's ratepayers the carrying cost of plants intended to provide service sometime in the future. ORS 757.355 equally prohibits charging tomorrow's ratepayers for the cost of providing utility service in the past. Deferring the cost of Colstrip 4 properly allocable to various months in 1986 and requiring 1987 ratepayers to pay those costs amounts to charging those ratepayers for property "not presently used for providing utility service to the customer."

Thus, H.B. 2145 would also be contrary to a measure enacted by the voters, which under Oregon law can only be modified by the voters, not by the Legislature.

Conclusion

H.B. 2145 would perpetuate the Oregon Public Utility Commissioner's unlawful practice of allowing private utilities to charge ratepayers for items of cost which have increased while ignoring items of cost which have declined. It would also allow private utilities to charge today's ratepayer for costs incurred to provide service in the past, whether or not the utility's rates in the past were sufficient to cover those costs. H.B. 2145 is contrary to the law governing utility rate regulation in other states and to Oregon's own law, ORS 757.355, enacted by the voters in 1978. I urge this Committee not to markup or report H.B. 2145 and that its consideration by this Committee cease.

DANIEL W. MEEK

2527 S.E. 17th Avenue
Portland, OR 97202
(503) 238-1742

EDUCATION

Stanford Law School	J.D. 1978
University of Wyoming	B.S. 1974

EMPLOYMENT

United States Congress

Staff Director and Energy Adviser January 1985 - February 1987	Subcommittee on General Oversight, Northwest Power, and Forest Management, U.S. House of Representatives Washington, D.C.
Senior Energy Adviser and Legal Counsel May 1983 - Dec 1984	Subcommittee on Mining, Forest Management, and the Bonneville Power Administration, U.S. House of Representatives Washington, D.C.

Authored October 1986 report exposing substantive and procedural error in the Department of Energy's selection of the Hanford Reservation in Washington as one of the 3 sites to be considered for the nation's first high-level radioactive waste repository.

Performed oversight of policies and operations of the Bonneville Power Administration (BPA), Northwest Power Planning Council, Bureau of Reclamation, Army Corps of Engineers, and other federal agencies involved in providing electricity in the Pacific Northwest.

California Energy Commission

Attorney and Adviser May 1980 - May 1983	California Energy Commission (CEC) Sacramento, California

Legal Assistant: 1978
Research Assistant: 1979

Principal Author of CEC's Electricity Tomorrow: 1981 Final Report on California electricity conservation and generation and responsible for CEC testimony on BPA to Congress and in the proceedings of BPA, the Western Area Power Administration and the California Public Utility Commission.

Law Practice

1982 - Present Attorney	Daniel W. Meek, P.C. Portland, Oregon

Represented ratepayers of Portland General Electric Co. (PGE), Pacific Power & Light Co. (PP&L), CP National Co., and Washington Water Power Co. before the Oregon Public Utility Commissioner and the Idaho Public Utility Commission and in subsequent litigation. In 1985, settlement of litigation pursued solely by my clients (Coalition for Safe Power and Forelaws on Board) required PGE to refund $14 million to its residential ratepayers (10% rate reduction for 8 months), to never charge or attempt to charge ratepayers any amount for the terminated Pebble Springs nuclear project, to forfeit its claim to charge ratepayers an additional $122 million for its terminated Skagit nuclear project, and to contribute $500,000 to charitable organizations undertaking environmental or ecological projects in the public interest of the residents of Oregon. Similar litigation against PP&L is in progress.

1979 - 1980 Associate	Stoel, Rives, Boley, Fraser & Wyse Portland, Oregon
1978 - 1979 Law Clerk	James M. Burns, Chief Judge U.S. District Court Portland, Oregon

National Academy of Sciences - National Research Council

1976 Analyst	National Research Council Committee on Nuclear and Alternative Energy Systems Washington, D.C.
1975 - 1976 Consultant	National Academy of Sciences Committee on Science and Public Policy Washington, D.C.

Stanford University

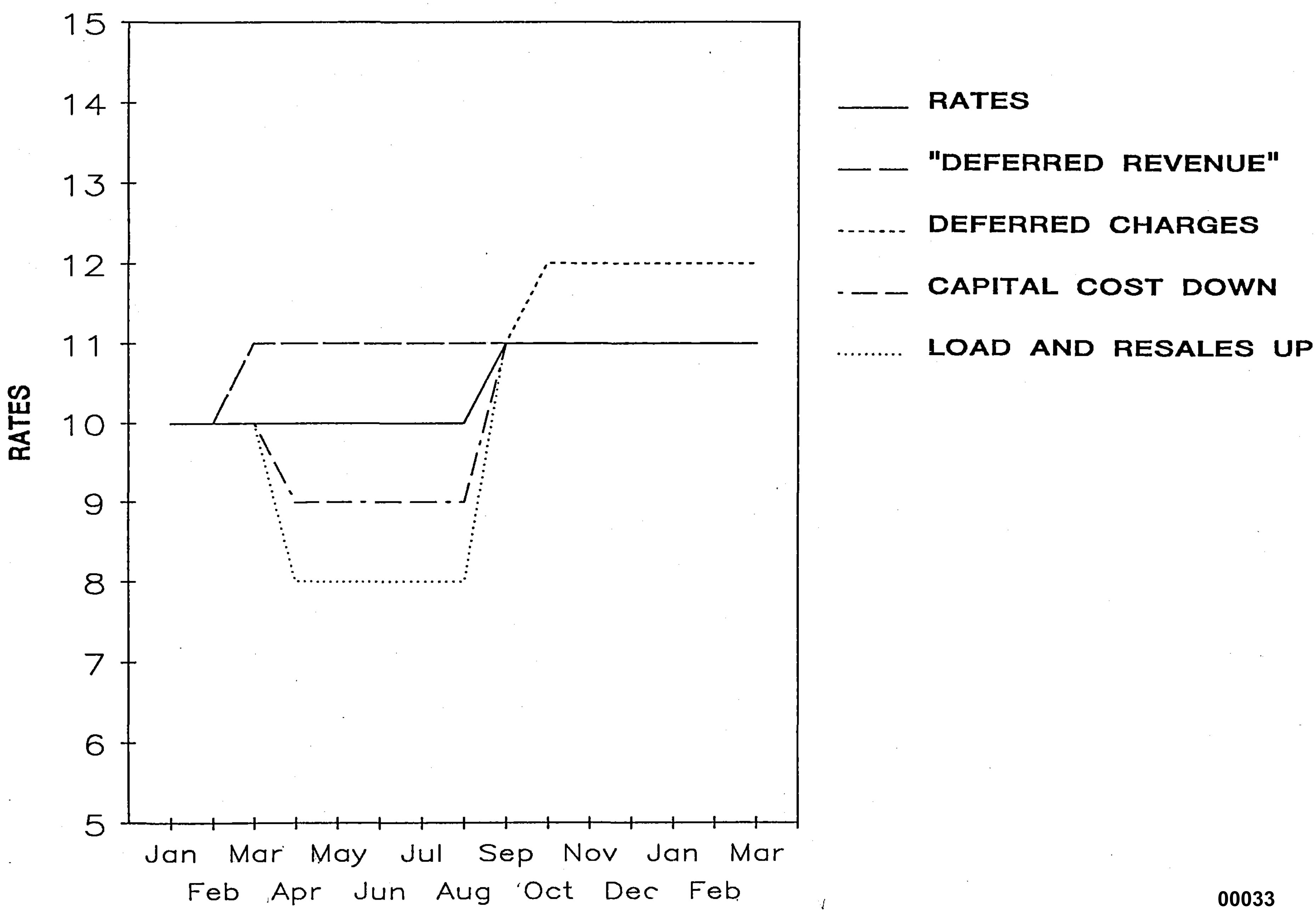
1974 - 1975 Research Assistant	Stanford University Department of Engineering-Economic Systems

Prepared papers on energy and environmental issues for member of Advisory Council to the Office of Technology Assessment (U.S. Congress).

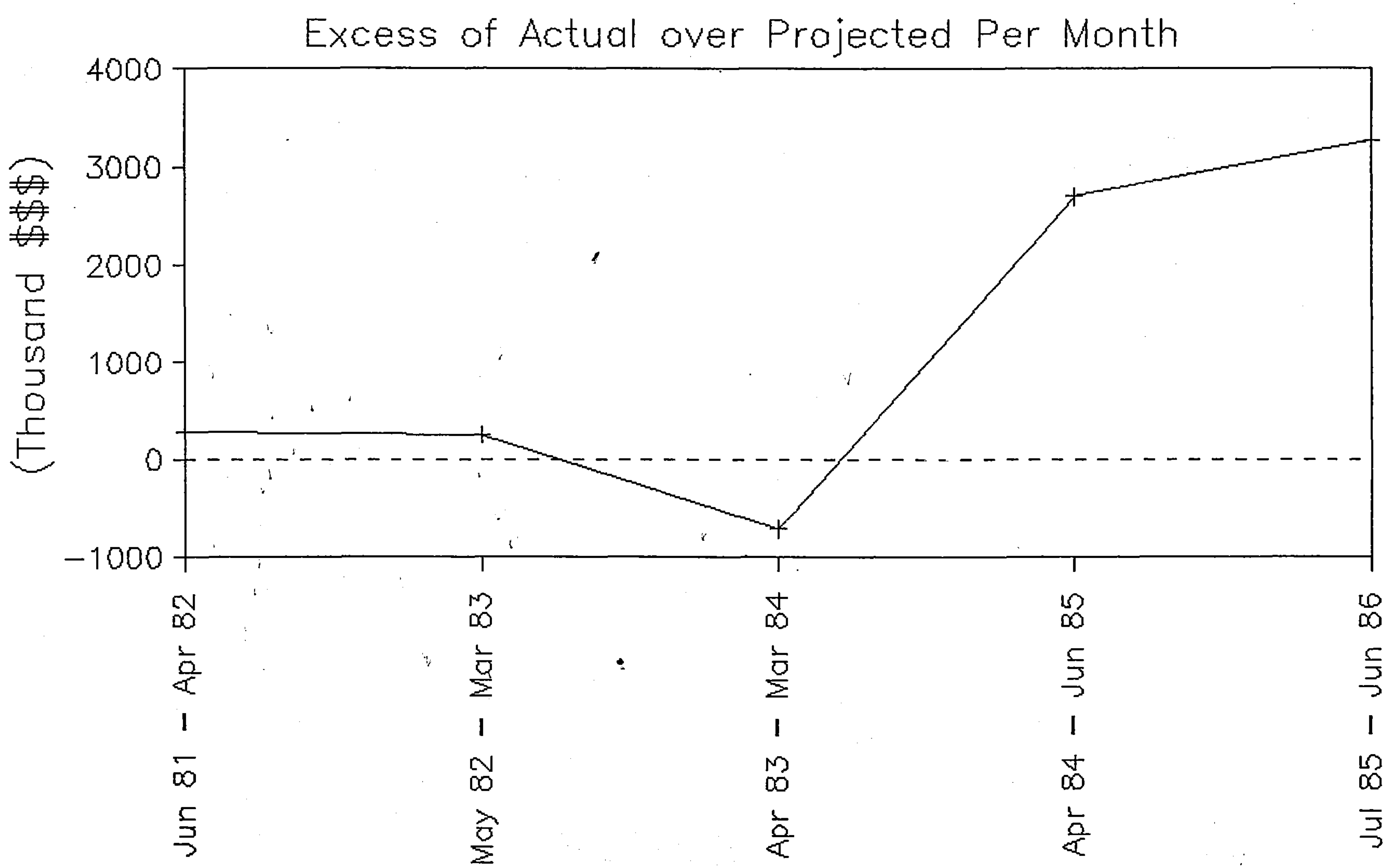
1974 - 1977 Director of Forensics	Stanford University

Instructed classes in economic and public policy research and supervised undergraduate intercollegiate debate program.

H.B. 2145: UTILITY RIP-OFF

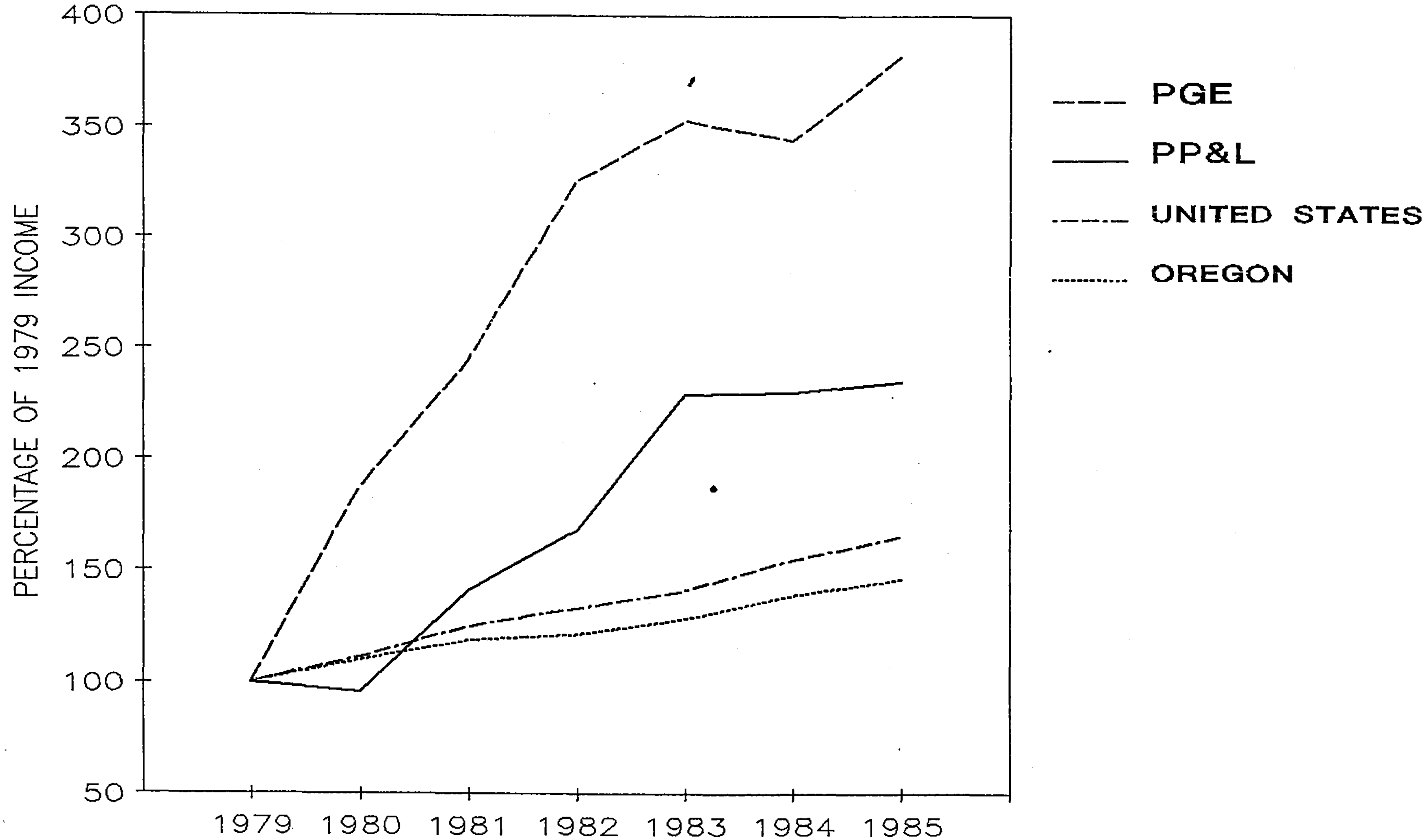


TREND IN PP&L RESALE FORECAST ERRORS



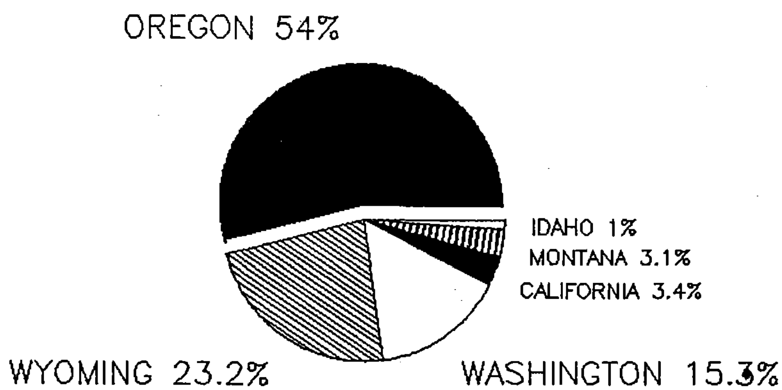
PGE AND PP&L V. THE ECONOMY

UTILITY NET INCOME V. OREGON AND U.S. PERSONAL INCOME
1979 - 1985

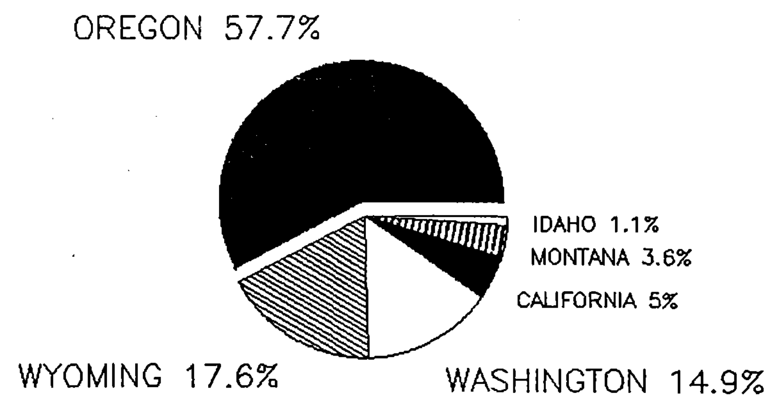


Base Year 1979 = 100. PP&L data for electric operations only

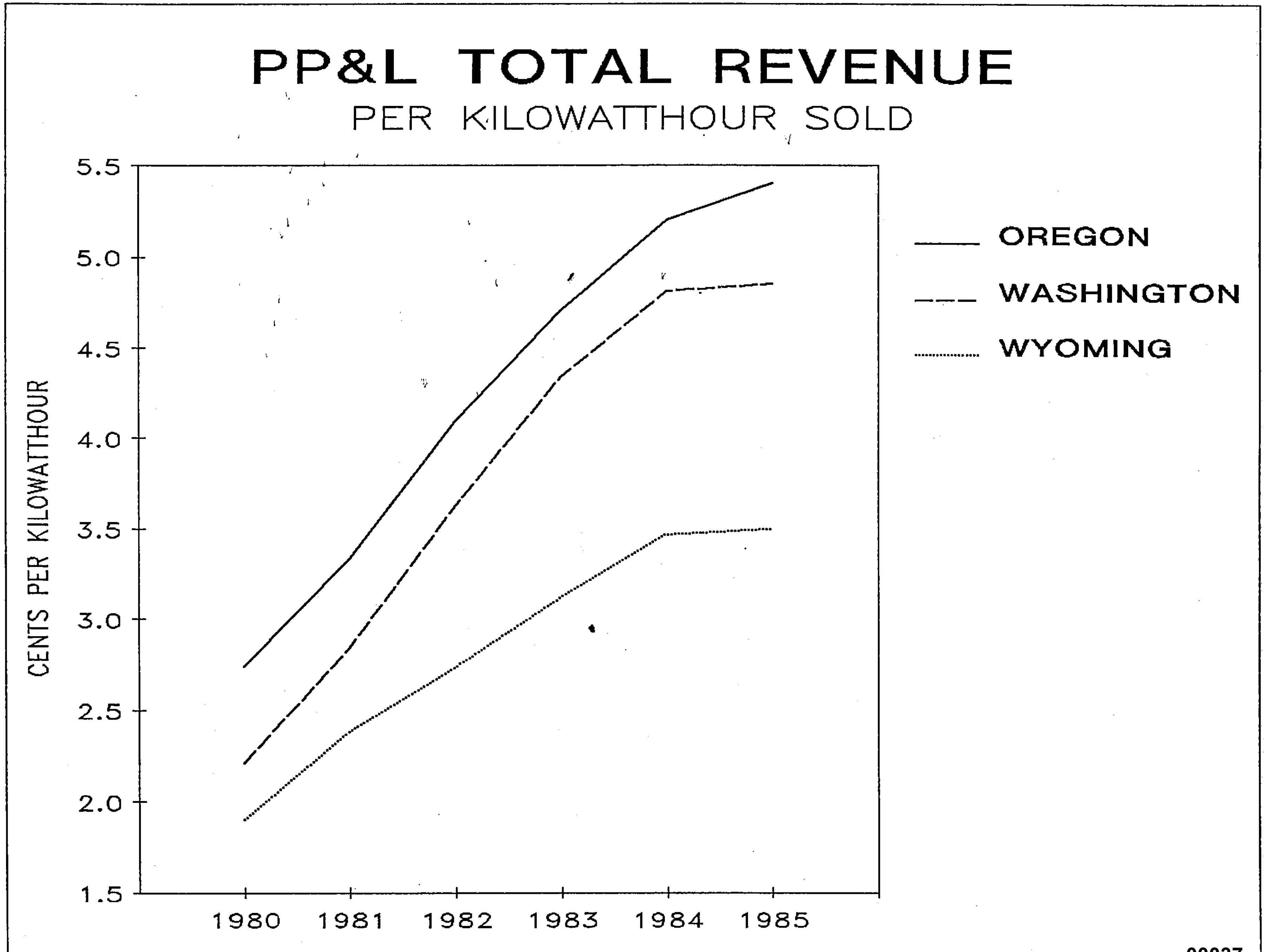
PP&L SERVICE AREAS
1985

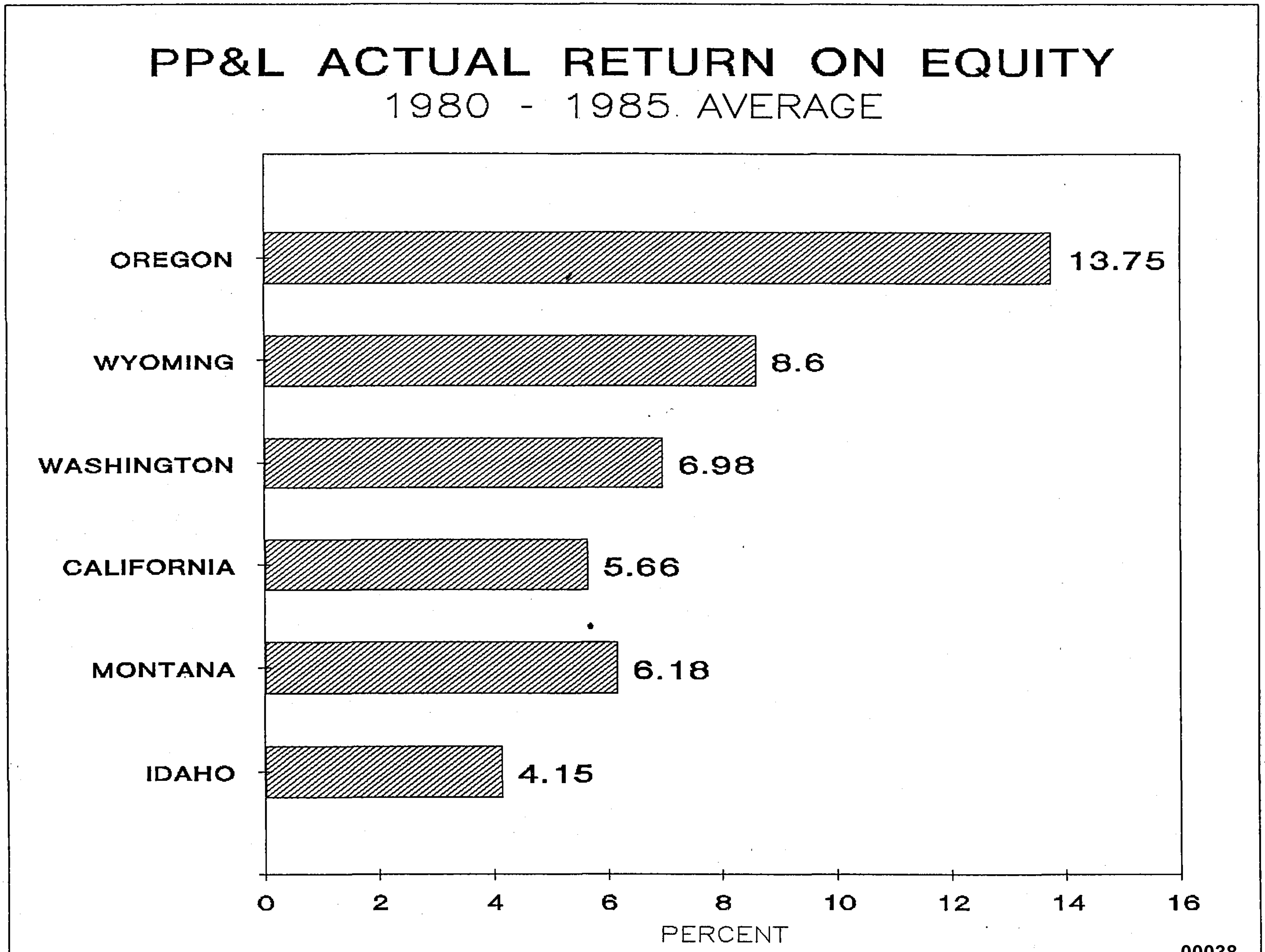


POWER



REVENUE


PP&L TOTAL REVENUE
PER KILOWATTHOUR SOLD
CENTS PER KILOWATTHOUR
5.5
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1980
1981
1982
1983
1984
1985
OREGON
WASHINGTON
WYOMING


PP&L ACTUAL RETURN ON EQUITY
1980 - 1985 AVERAGE
OREGON
13.75
WYOMING
8.6
WASHINGTON
6.98
CALIFORNIA
5.66
MONTANA
6.18
IDAHO
4.15
0
2
4
6
8
10
12
14
16
PERCENT

HOUSE [illegible] ENERGY
Bill No. HB 2145 2
Exhibit D 3/25/87
Presented JOHN LOBDELL
NW NAT. GAS

A BILL FOR AN ACT

Relating to public utilities.

Be It Enacted by the People of the State of Oregon:

SECTION 1. Section 2 of this Act is added to and made a part of ORS chapter 757.

SECTION 2. (1) In addition to powers otherwise vested in the commission, and subject to the limitations contained in subsection (6) of this section under amortization schedules set by the commission, a rate or rate schedule may reflect the following:

(a) Amounts lawfully imposed retroactively by order of another governmental agency; or

(b) Amounts deferred under subsection (2) of this section.

(2) Upon application of a utility and after public notice and opportunity for comment, the commission by order may authorize deferral of the following amounts for later incorporation in rates:

(a) Amounts incurred by a utility resulting from changes in the wholesale price of natural gas or electricity approved by the Federal Energy Regulatory Commission;

(b) Balances resulting from the administration of Section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act of 1980; or

(c) [Amounts incurred by a utility] <u>Utility expenses or revenues</u> the recovery of which the commission finds should be deferred in order to minimize the frequency of rate changes or the fluctuation of rate levels or to match appropriately the costs borne by and benefits received by ratepayers.

(3) The commission may authorize deferrals under this section commencing with the date of application by the utility, together with interest established by the commission.

(4) Unless subject to an automatic adjustment clause under ORS 757.210(1), amounts described in this section shall be allowed in rates only to the extent authorized by the commission in a proceeding to change rates under ORS 757.210 and upon review of the utility's earnings at the time of application to amortize the deferral.

(5) Amounts to the extent they have accrued in deferred accounts with commission authorization prior to the effective date of this 1987 Act also may be reflected in rates. However, continued use of such accounts<u>, except accounts that have been or are authorized by a final order of the commission in a proceeding to change rates under ORS 757.210,</u> shall require further authorization of the commission under subsection (2) of this section.

(6) In any one year, the [sum] <u>rate impact</u> of the amortizations authorized [under this] <u>by</u> <u>sub</u>section <u>(2)(c)</u> shall not exceed 3 percent of the utility's gross revenues for the preceding calendar year.

HOUSE [illegible] ENERGY
Bill No. HB 2145 25
Exhibit F 3/30/87
Presented by B. WARREN

PUBLIC UTILITY COMMISSIONER OF OREGON

NEIL GOLDSCHMIDT
GOVERNOR

LABOR & INDUSTRIES BUILDING, SALEM OREGON 97310 PHONE (503) 378-6053

March 30, 1987

Representative Ron Cease
Chair, House Environment &
Energy Committee
House of Representatives
Salem OR 97310

RE: House Bill 2145

At the Committee's hearing on March 25, 1987, Representatives Eachus and Parkinson requested certain information. The information requested is enclosed, as follows:

1. A memorandum defining significant terms used in the context of this legislation.

2. A chronology of events concerning the recently concluded Pacific Power & Light rate case (UE 52).

In light of certain testimony presented to the Committee on March 25, please allow me to observe the following few points:

1. All deferrals authorized by the Commissioner in UE 52 were subject to adjustment or reversal pending final hearings and accrued interest at the final authorized cost of capital in that proceeding. These accruals therefore reflected the cost of capital reductions recognized by the Commissioner in January 1987, when an order was signed in UE 52.

2. Of the account data provided to the Committee on March 25, a great many involve credits (rate reductions) to ratepayers. A copy of the account data previously supplied is attached to this letter. We do not only defer cost increases. This material also reflects which accounts were established within the context of a general rate proceeding pursuant to ORS 757.210 (denoted by a "C").

3. All of our settlement discussions in rate cases are open to all participants and all are invited, in writing, to attend. Furthermore, the record will show that we aggressively review utility rate filings. For your information, I am enclosing staff's adjustment summary for both the PGE and PP&L rate cases to give the Committee an indication of the issues addressed in our reviews.

I have discussed with the Commissioner the amendments to HB 2145 proposed by Northwest Natural on March 25. The Commissioner does not oppose Northwest's amendment to Section 2(2)(c). He does not support the revision to Section 2(5). The Commissioner feels that the three-member Commission should have the opportunity to review the propriety of all existing accounts. Lastly, the Commissioner does not support the amendment to Section 2(6), which restricts application of the three-percent cap only to Section 2(2)(c) items. He feels that a three-percent per-year authorization for these types of activities is sufficient. Frankly, we feel that utilities would normally prefer amortizations that will lessen the immediate effect on ratepayers and thus will not generally seek amortizations exceeding three percent in any event.

Finally, Mr. Meek did raise a valid point regarding Section 2(2). The Commissioner supports amendment of the language reading "upon application of a utility and" to "upon application [of a utility] and." The intent of deleting this wording is to allow any interested party to petition the Commission regarding deferred accounting matters and not to limit this ability only to utilities.

I hope this information is helpful. Please call me if I can be of further assistance.

William G. Warren
Assistant Commissioner
Utility Program

llv/0352H

Enclosure

cc: Members of House Environment & Energy Committee

PUBLIC UTILITY COMMISSIONER OF OREGON
INTER-OFFICE CORRESPONDENCE

(NOT FOR MAILING)

DATE: March 30, 1987

TO: Bill Warren

FROM: Ray Lambeth

SUBJECT: Glossary of Terms - HB 2145

The House Energy and Environment Committee asked for a glossary of terms in connection with HB 2145, the deferred accounting and ratemaking bill.

Attached to this memorandum is a copy of the glossary from the Public Utilities Manual published by Deloitte Haskins & Sells. The attachment defines many of the basic utility accounting and ratemaking terms.

In addition, I offer the definitions below, which are somewhat more oriented to the legislation and the recent Attorney General's opinion.

1. Accounting - Ratemaking. For a regulated company, accounting practices and entries are largely controlled by the ratemaking treatment. Ratemaking decisions can create assets and liabilities by postponement of recognition of transactions which would enter into the determination of income for a non-regulated firm entirely in one period or at an earlier time.

2. Amortization. The collection or refunding in rates of deferrals previously authorized by the Commissioner. For a regulated utility, amortization is designed to match increases or decreases in revenues allowed to be collected from customers.

3. Automatic Adjustment Clause. A mechanism under the terms of which rates can be adjusted without the normal notice and hearings requirements.

4. Balancing Account. A balance sheet account which accumulates the difference between revenues collected or foregone and the actual expenditure or income realized.

5. Cost of Service Adjustment Clause. A mechanism under the terms of which rates can be adjusted to reflect excesses or shortfalls of utility cost of service elements from the levels needed to construct tariffs. May or may not be an automatic adjustment clause and may cover some or all cost of service elements.

6. Deferral. The postponement of recognition of income or expense amounts. Deferrals may be subject to amortization, if rate recovery is permitted, or may be fully reflected in one period's income statement, if rate recovery is denied. A deferred charge or debit account can increase required revenues, and a deferred credit account can decrease required revenues.

7. Gross Revenues. The sum of all revenues recorded for utility operations, including sales to consumers, sales for resale, and other operating revenues.

8. Revenue Adjustment Clause. A mechanism under the terms of which future rates can be adjusted to reflect increases or shortfalls of utility revenues from the levels used to construct tariffs. May or may not be an automatic adjustment clause and may cover some or all revenue categories.

9. Tariff. Specifications of rates, customer classes, and terms and conditions of service.

tl/0386H

Attachment

Deloitte Haskins+Sells

USA

Public Utilities Manual

Appendixes

Glossary

Acquisition adjustment. The difference between the cost of acquiring an **operating unit or system** and the depreciated **original cost** of the acquired property. (Note: Any existing **contributions in aid of construction** are also carried through the property transfer and reinstated by the new owner, thus affecting the amount of recorded acquisition adjustment.)

Average load. The total production for the period divided by the hours in the period.

Below the line. All income statement items of revenue and expense not included in determining **net operating income.** If the item falls below the net operating income line of the income statement, it is labeled a below-the-line item. Net operating income is the "line" referred to.

Capital intensive. A term used to designate a condition in which a relatively large dollar investment is required to produce a dollar of revenue. The electric industry, for example, has an investment of about $4.00 for each dollar of revenue generated annually.

Contributions in aid of construction. Nonrefundable donations or contributions in cash or properties from individuals, governmental agencies or others for construction or property-addition purposes.

Cost of capital. The composite rate of cost for debt interest, preferred stock dividends and common stockholder earnings requirements. It is the composite of the cost of the various capital sources used to provide the facilities utilized in supplying utility service.

Cost of service. The total cost of providing utility service to the system or to a group therein (the latter is commonly referred to as an allocated cost of service). The cost components include operating expenses, depreciation, taxes and a **rate of return** adequate to service investment capital. Cost of service is synonymous with the **revenue requirements** of the system (or segment thereof).

Cycle billing. The process of reading a segment of the system meters and billing that portion of the system's customers each day of a billing period. By the end of the cycle, the complete system is read and billed, and a new cycle begins. The customer reading on each day of the cycle will reflect the use for a full period so that the o00045tomers up to date at the end of the accounting period are those read and billed of the last day of the cycle. All other customers will have unread and unbilled consumptions of from one to thirty days. assuming a one-month cycle. This produces an **unbilled revenue** at the end of each accounting period.

Deferred fuel costs. The amount of fuel costs applicable to service rendered in one accounting period that will not be reflected in billings to customers until a subsequent accounting period. Balance-sheet deferral may be required to match these costs properly with related revenue.

Diversity factor. The sum of noncoincident demands of a group divided by the group coincident demand. For example, if two customers have 1 KW of demand each, but at different times during the day, the diversity factor is $(1 + 1)/1 = 2$.

Embedded costs. Those costs that are in existence at any point in time regardless of the date originally incurred and that affect current operations on a continuing basis.

Extraordinary losses. The Uniform Systems provide that, in normal circumstances, property retirements be made through the accumulated depreciation accounts without recognition of gains and losses. Where such retirements are unusual, unexpected and "could not reasonably have been foreseen and provided for," losses normally result and are treated as extraordinary and set up in Account 182, Extraordinary Property Losses. The resultant charge to Account 182 is most often amortized over a five- to ten-year period and is quite often allowed "above the line" for rate purposes as a means of allowing the full recovery of the investment originally committed to public service.

Fair market value. Generally the term applies to the amount that a willing buyer will pay a willing seller in an arm's-length transaction. Because of the predominant use of **original cost** in the **rate base** and the constraints that original-cost factors place on the rates that may be charged, the depreciated book cost of utility plant may be a prominent factor in establishing fair market value for a utility system.

Fair value. A term normally used in those jurisdictions that, by statute or regulatory precedent, allow the **rate base** to be expressed at a level other than the recorded **original cost** amounts. The most common measure of fair value is reflected in a composite of original cost and **trended original cost** factors. In practice the fair value figure has often been closer to the original cost level than the trended original cost level.

Firm power. Power which is intended to have assured availability to the customer to meet all or any agreed-upon portion of his load requirements.

Heat rate. A measure of generating station thermal efficiency, generally expressed as BTU per net kilowatt-hour. It is computed by dividing the total BTU content of fuel burned by the resulting net kilowatt-hours generated.

Historic cost. The initial cost to the person who holds the property. **Original cost** and historic cost are the same where property has not changed ownership. When utility property of an **operating unit or system** nature changes ownership, the original cost carries forward and is maintained by the new owner, although his purchase price (i.e., historic cost to the new owner) may be something different.

Interchange energy. Electric energy received from or delivered to another electric utility system under an interconnection or power pool agreement. Interchange energy may be settled in cash or by future exchange of energy.

Load factor. The average load of a customer, a group of customers or the system divided by the maximum load. For example, assuming 48 KWH of usage for the day, the average load is 48/24 or 2 KW. If the maximum capacity available is 4 KW, the load factor is $2/4 = 50$ percent.

Net operating income. The amount of revenues from utility operations that remains after the deduction of the operating and maintenance expenses, depreciation expenses and taxes (income, property, etc.) attributable to the utility operation. The revenues and expenses that are measured to produce net operating revenue are commonly referred to as "above-the-line" items. The revenues and expenses measured apart from net operating income are referred to as "below-the-line" items. The net operating income line on the income statement is the dividing point. (See also **below the line.**)

Net original cost. Original cost less accumulated depreciation.

Nonoperating items. Although sometimes used interchangeably with **nonutility items,** this term may more properly be used to describe items such as construction work in progress which is not currently used in providing utility services. It has also been applied traditionally to financial items (e.g., interest expense).

Nonutility items. All items of revenue, expense and investment not associated, either by direct assignment or by allocation, with providing

Operating unit or system. Although not clearly defined by the Uniform System of Accounts, this term generally relates to a complete and self-sustaining facility or to a group of facilities acquired and operated intact as a segment of a complete system.

Original cost. Cost of property to the one who first devoted it to public use.

Peak demand. The maximum level of operating requirements (i.e., production) placed upon the system by the customer usage during a specified period of time (e.g., instantaneous peak, thirty-minute peak, one-hour peak and one-day peak outputs are common points of reference). It may be measured by an operating segment of the company, such as a customer class, or for the entire company, depending on intended use of the data.

Rate base. The investor-supplied plant facilities and other assets used in supplying utility service to the consumer. This investment base is the amount to which the **rate of return** is applied (i.e., Rate Base × Rate of Return = Net Operating Income).

Rate of return. The *realized* rate of return is the percentage factor obtained by dividing the **net operating income** from utility operations by the **rate base.** An *adequate* rate of return is the percentage factor that, when multiplied by the rate base, produces earnings that will meet the interest and equity requirements of the capital used to support the rate base. The measure of the adequacy of the rate-of-return factor is usually based upon cost-of-capital measurements.

Replacement cost. An estimate of the cost to replace the existing facilities (either as currently structured or as redesigned to embrace new technology) with facilities that will perform the same functions. This method recognizes the benefits of presently available technology in replacing the system. For example, a number of small generating units may be replaced with a single large unit at lower unit costs and greater efficiency.

Reproduction cost. The estimated cost to reproduce existing properties in their current form and capability at current cost levels. The mechanics may involve a trending of the original cost dollars to reflect current costing factors, or they may involve a property appraisal accompanied by estimates to reconstruct the facilities (the former is most often utilized).

Revenue requirements. The sum total of the revenues required to pay all operating and capital costs of providing service.

Test year. The twelve-month operating period selected to evaluate the **cost of service** and the adequacy of the rates in effect or being sought. Frequently the term "test period" is used, and may refer simply to the test year or expressly to the *adjusted* test year.

Trended original cost. The result of isolating original-cost plant additions by year of placement and factoring the original amounts upward to recognize subsequent changes in the cost of constructing plant facilities. The object is usually to restate installed cost of facilities at current levels.

Unbilled revenues. The amount of service rendered but not recorded or billed at the end of an accounting period. Cycle meter reading practices result in unrecorded consumption between the date of last meter reading and the end of the period. If these amounts are not estimated and recorded, they reflect "unbilled" amounts.

Utilization factor. The ratio of the maximum demand of a system to the installed capacity of the system.

Value of service. A concept in utility pricing practices whereby the usefulness or necessity of the service to a customer group replaces cost factors as a major influence on the rates charged to the group.

Wheeling. An electric operation wherein transmission facilities of one system are utilized to transmit power of another system.

Working capital. Used broadly, the term refers to those rate-base allowances other than the utility plant in service and may include material, fuels, supplies, etc. In the narrower use, commonly referred to as cash working capital, it relates to the investor-supplied funds necessary to meet operating expense or going-concern requirements of the business. There is normally a time lag between the point when service is rendered and the related operating costs are incurred and the point when revenues to recover such costs are received. The operating funds to bridge the lag are usually supplied by the investor and become a fixed commitment to the enterprise.

PUBLIC UTILITY COMMISSIONER OF OREGON
INTER-OFFICE CORRESPONDENCE

(NOT FOR MAILING)

DATE: March 27, 1987

TO: Bill Warren

FROM: Scott Girard SG

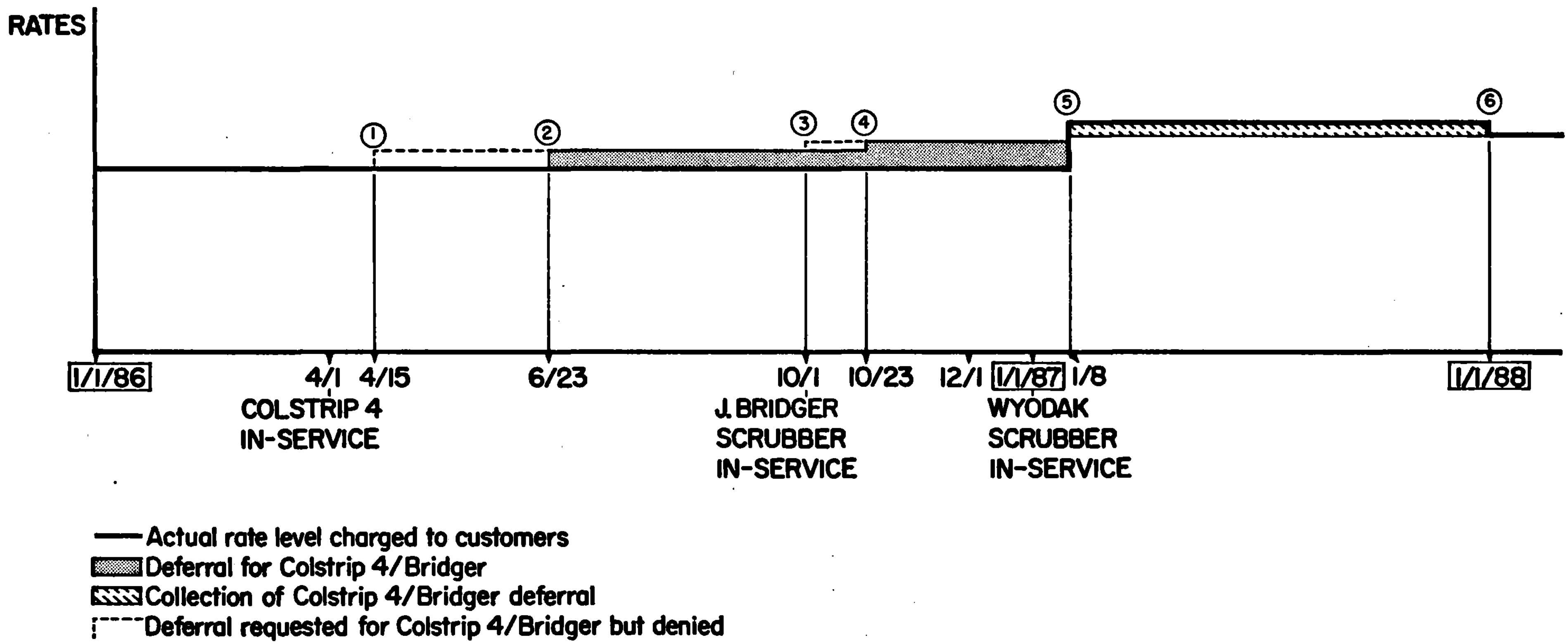
SUBJECT: Chronology of Pacific Power & Light UE 52 - 1986 Rate Case

A chart depicting the events in UE 52 is attached. Listed below is a description of these events:

Date	Event
3/25/86	PP&L requested deferred accounting for Colstrip 4 effective 4/15/86.
4/1/86	Colstrip 4 in-service date.
4/23/86	Commissioner authorized in Order 86-411 deferred accounting for Colstrip 4 effective 4/15/86.*
6/16/86	PP&L filed rate case seeking 4 percent increase, for the ongoing level of Colstrip 4 and Jim Bridger scrubber and the deferred portion of Colstrip 4, effective 10/1/86 and interim authority to include Colstrip 4 in rates effective 6/23/86 on a deferred basis.
6/20/86	Commissioner authorized in Order No. 86-605 Colstrip 4 deferred revenue effective 6/23/86.*
9/15/86	PP&L requested interim authority to include Jim Bridger Unit 2 scrubber effective 10/1/86 on a deferred basis.
10/1/86	Jim Bridger Unit 2 scrubber in-service.
10/23/86	Commissioner authorized in Order No. 86-1078 Jim Bridger Unit 2 scrubber in rates on a deferred basis effective 10/23/86.*
12/1/86	Wyodak scrubber in-service.
1/8/87	Commissioner authorized in Order No. 87-034 a 4 percent increase in rates including the deferral portion of Colstrip 4 and Jim Bridger scrubber and an ongoing level for Colstrip 4, Jim Bridger, and Wyodak scrubbers. Denies collection in rates of Colstrip 4 prior to 6/23/86.

* These authorizations were subject to adjustment or reversal if any party in UE 52 demonstrated in hearings that these costs should not be included in rates.

PP&L
RATE LEVEL CHART
FOR
UE-52 1986 GENERAL RATE CASE



① PP&L REQUESTED EFFECTIVE DATE FOR COLSTRIP 4 DEFERRAL
② COLSTRIP 4 DEFERRAL EFFECTIVE DATE
③ PP&L REQUESTED EFFECTIVE DATE FOR J. BRIDGER DEFERRAL
④ J. BRIDGER DEFERRAL EFFECTIVE DATE
⑤ ORDER 87-034 AUTHORIZED A 4% RATE INCREASE, 2.7% PERMANENT INCREASE AND 1.3% TEMPORARY INCREASE FOR COLLECTION OF DEFERRAL
⑥ ESTIMATED DATE WHEN COLLECTION OF DEFERRALS WOULD END

ENERGY UTILITY DEFERRED ACCOUNTS

Covered by Attorney General's Opinion of March 18, 1987

Summary List as of December 31, 1986

Description	$ Balance Incr. or (Decr.)	% of 1986 Oregon Revenues	Reason for Deferral*
PORTLAND GENERAL ELECTRIC			
RPA Balancing Account (A)	$ 18,758,783	2.836%	3
IBP Deferral	660,000	.100	5
PCA Balancing Account (C)	(3,563,000)	(.539)	5
Capital Restructuring Program Deferral	14,258,566	2.155	5
State Tax Normalization Deferral	517,000	.078	5
Pole Inspection Program Deferral (C)	883,761	.134	5
WHIP Admin. Indirect	924,000	.140	5
Weatherization Program - Admin. Costs (B)	22,000	.003	5
Water Heater Wrap - Summer Blitz	81,000	.012	5
WHIP - Direct Incentives	392,000	.059	5
Water Heater Wrap Program	355,000	.054	5
Low Income Weather. Program	140,000	.021	5
Uncollectible Weatherization Write-Off	586,000	.089	5
Unamortized Indirect Costs - Weather. Program (B)	4,944,000	.747	5
Total	$ 38,959,110	5.789%	
CP NATIONAL - ELECTRIC			
RPA Balancing Account (A)	$ (825,464)	(3.213)	3
Inverted Rate Balancing Account	(374,031)	(1.456)	5
CSPP Deferrals	2,480,726	9.655	5
Total	$1,281,231	4.986%	

*Key to Reasons for Deferral.
1. Retroactive changes imposed by a governmental agency.
2. Wholesale price change approved by the Federal Energy Regulatory Commission.
3. Regional Power Act changes.
4. Minimize frequency of rate changes or fluctuations of rate levels.
5. Match costs and benefits or actual costs.

Footnotes:
(A) This account may be exempt from application of the Attorney General's opinion because of the provisions of Section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act of 1980.
(B) Part of the balance in this account may be exempt from application of the Attorney General's opinion because of the specific statutory provision that actual program costs be recovered.
(C) Established within the context of a general rate proceeding under ORS 757.210.

Note: Accounts with credit balances may be exempt from application of the Attorney General's opinion if the utility has a binding commitment to reduce rates to reflect amortization of the balance.

ENERGY UTILITY DEFERRED ACCOUNTS

Covered by Attorney General's Opinion of March 18, 1987

Summary List as of December 31, 1986

Description	$ Balance Incr. or (Decr.)	% of 1986 Oregon Revenues	Reason for Deferral*
PACIFIC POWER & LIGHT COMPANY			
RPA Balancing Account (A)	$ (353,129)	(.067)	3
Recapitalization Program	1,651,993	.314	5
IBP Deferral	(1,025,933)	(.195)	5
Colstrip 4 Deferral (C)	5,876,741	1.115	4
Jim Bridger Pollution Control Deferral (C)	1,788,555	.339	4
Weatherization Loan Program - 0% Interest	3,705,907	.703	5
Residential Water Heater Wrap Program	38,325	.007	5
Hood River Conservation Program	(8,521)	(.002)	5
Total	$11,673,938	2.214%	
IDAHO POWER COMPANY			
CSPP Deferrals	$545,465	3.229%	5
IBP Deferral	42,454	.251	5
Total	$587,919	3.480%	

*Key to Reasons for Deferral.

1. Retroactive changes imposed by a governmental agency.
2. Wholesale price change approved by the Federal Energy Regulatory Commission.
3. Regional Power Act changes.
4. Minimize frequency of rate changes or fluctuations of rate levels.
5. Match costs and benefits or actual costs.

(A) This account may be exempt from application of the Attorney General's opinion because of the provisions of Section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act of 1980.

(C) Established within the context of a general rate proceeding under ORS 757.210.

Note: Accounts with credit balances may be exempt from application of the Attorney General's opinion if the utility has a binding commitment to reduce rates to reflect amortization of the balance.

ENERGY UTILITY DEFERRED ACCOUNTS

Covered by Attorney General's Opinion of March 18, 1987

Summary List as of December 31, 1986

Description	$ Balance Incr. or (Decr.)	% of 1986 Oregon Revenues	Reason for Deferral*
NORTHWEST NATURAL GAS			
ISA Deferral (C)	$5,610,833	2.067%	5
	229,755	.085	5
ISA Amortization	987,069	.364	5
TSSA Balancing Accounts (C)	(554,615)	(.204)	5
	(689,436)	(.254)	5
TSSA Contribution Account (C)	(731,407)	(.269)	5
Uncollectible Weatherization Contracts	(8,709)	(.003)	5
Throop Weatherization Survey Costs	220,126	.081	5
Def. Steam Heat Balancing Account (C)	92,535	.034	5
1986 Leakage Réconstruction Program (C)	1,214,903	.448	5
Interim Rate Increase (C)	517,768	.191	4
Transportation Increment	156,044	.057	5
Northwest Pipeline Refund	304,988	.112	2
Northwest Pipeline IS-1 Savings	(172,945)	(.064)	2
Northwest Pipeline D-1 Charge	46,645	.017	2
Northwest Pipeline Demand Chg. Credit	(452,731)	(.167)	2
Def. Cost of Gas Amortization	(65,331)	(.024)	2
Cost of Gas Amort.	(274,755)	(.101)	2
Northwest Pipeline Refund	(69,663)	(.026)	2
Northwest Pipeline Section 104 Refund	(266,359)	(.098)	2
Def. Gas Cost Decrease	(435,431)	(.160)	2
Def. Gas Cost	318,520	.117	2
CIG Refund	(504,608)	(.186)	2
Total	$5,473,196	2.017%	

*Key to Reasons for Deferral.

1. Retroactive changes imposed by a governmental agency.
2. Wholesale price change approved by the Federal Energy Regulatory Commission.
3. Regional Power Act changes.
4. Minimize frequency of rate changes or fluctuations of rate levels.
5. Match costs and benefits or actual costs.

(C) Established within the context of a general rate proceeding under ORS 757.210.

Note: Accounts with credit balances may be exempt from application of the Attorney General's opinion if the utility has a binding commitment to reduce rates to reflect amortization of the balance.

ENERGY UTILITY DEFERRED ACCOUNTS

Covered by Attorney General's Opinion of March 18, 1987

Summary List as of December 31, 1986

Description	$ Balance Incr. or (Decr.)	% of 1986 Oregon Revenues	Reason for Deferral*
CASCADE NATURAL GAS			
Oregon Water Heater Program	68,930	.323	5
Astoria Cleanup Costs	315,000	1.474	5
Oregon 8/1/86 Gas Cost Decrease	(177,630)	(.831)	2
Northwest Pipeline Demand Chg. Credit	(53,683)	(.251)	2
1986 Northwest Pipeline Refunds	(69,313)	(.324)	2
Northwest Pipeline Commodity Cost Decreases	(63,261)	(.296)	2
Oregon Gas Cost Reduction Credit (4/85)	33,436	.156	2
Oregon 5/85 Technical Adj. No. 1	13,181	.062	2
Oregon 5/85 Technical Adj. No. 3	3,454	.016	2
Oregon 5/85 Technical Adj. No. 2	(2,865)	(.013)	2
Oregon 7/1/85 Gas Cost Decrease	(1,319)	(.006)	2
11/1/86 Oregon Demand Cost Increase	14,283	.067	2
Total	$ 80,213	0.377%	
CP NATIONAL - GAS			
ISA Balancing Account (C)	$(28,426)	(.098)	5
Northwest Pipeline Refund	(66,989)	(.231)	2
CIG Surcharge Refund	(51,796)	(.179)	2
I.S. Overcollection	(21,293)	(.073)	2
Incentive Gas Overcollection	(10,078)	(.035)	2
Interim Commodity Cost Balancing Account	(81,197)	(.280)	2
Northwest Pipeline 11/1/86 Decrease	(88,328)	(.305)	2
$150 Water Heater Rebate Deferral	62,376	.215	5
Total	$(285,731)	(0.986)%	

*Key to Reasons for Deferral.
1. Retroactive changes imposed by a governmental agency.
2. Wholesale price change approved by the Federal Energy Regulatory Commission.
3. Regional Power Act changes.
4. Minimize frequency of rate changes or fluctuations of rate levels.
5. Match costs and benefits or actual costs.

(C) Established within the context of a general rate proceeding under ORS 757.210.

Note: Accounts with credit balances may be exempt from application of the Attorney General's opinion if the utility has a binding commitment to reduce rates to reflect amortization of the balance.

ENERGY UTILITY DEFERRED ACCOUNTS

Not Covered by Attorney General's Opinion of March 18, 1987

Summary List as of December 31, 1986

Description	$ Balance Incr. or (Decr.)	% of 1986 Oregon Revenues
Property Sales		
Portland General Electric		
Boardman	$(96,605,174)	(14.604)
Columbia - Willamette	(2,333,750)	(.353)
Statutory Mandate		
Portland General Electric		
Weatherization Rebate Program	226,000	.034
Comm./Ind. Energy Mgt. Program	987,000	.149
Pacific Power & Light		
Weatherization Loans - 6 1/2%	458,857	.087
Commercial Conservation Program	340,115	.065
Nuclear Waste Disposal Costs	228,408	.043
Idaho Power		
Weatherization Loans - 6 1/2%	99,737	.590
Cascade Natural Gas		
Weatherization Costs	(13,455)	(.063)
Commercial Weatherization	2,040	.010
Utility Commitment for Rate Reductions		
Portland General Electric		
Nuclear Fuel Storage Collection *	(5,986,748)	(.905)
BPA Weatherization Refunds	(929,000)	(.140)
Northwest Natural Gas		
Special Purchase Gas Savings	(131,993)	(.049)
Special Purchase Gas Savings	(706,981)	(.260)
Cascade Natural Gas		
Self-Help Gas Cost Credit - 1985	(41,662)	(.195)
Self-Help Gas Cost Credit - 1986	(189,464)	(.887)

*If this account had not been amortized to offset interim Colstrip No. 4 costs, the balance would have been about $(33.4) million.

Notes:

1) If a deferred account had been authorized to accumulate Portland General Electric's Colstrip No. 4 costs, the balance at year-end 1986 would have been about $27.4 million.

2) As of March 1, 1987, Pacific Power & Light began voluntarily to defer for the ratepayers' benefit rate reductions arising from the Tax Reform Act of 1986 in the approximate annual amount of $(13.2) million.

PORTLAND GENERAL ELECTRIC CO.

Summary of Company and OPUC Staff Stipulations
As To Revenue Requirements
Before Tax Reform Act of 1986 Changes

UE 48 - 1987 Test Year
($ x 1,000)

Staff	Description	Revenue Requirement Effect
	Company's initial calculated revenue requirement.	$ 67,017
	Stipulated Changes	
PN	1. Rate of Return. The company's filing contains a requested overall rate of return of 11.93 percent based on an embedded long-term debt cost rate of 10.07 percent and a return rate on common equity of 14.09 percent. The stipulated overall rate of return of 11.14 percent embodies an embedded long-term debt cost rate of 9.71 percent and a return rate on common equity of 12.75 percent. The reduction in the cost of long-term debt from the company's filed cost rate is due to the use of more current information regarding financings. The 12.75 percent rate of return on common equity is within staff's range of 11.75 percent to 13.00 percent.	(27,775)
RL	2. Revenue-Sensitive Costs. The company filing includes a revenue-sensitive factor for interest which is eliminated in the stipulated case. However, the stipulated revenue-sensitive factor for franchise fees is higher than in the company filing because of more recent information.	(1,028)
MH	3. WNP-3 Settlement. The company filing proposed to include $113 million in rate base and amortize that value over the contract life of 31 years. The rate base amount was derived by reference to the difference between revenues required for settlement-related purchased power costs and an added energy equivalent share of Colstrip 4. The stipulation is based on a marginal cost valuation from which a stream of power cost charges was derived. See testimony.	(19,891)
PN	4. Equity Issuance Costs. The company filing contains a requested return on common equity which reflects an upward adjustment made for the purpose of allowing it to recover common stock issuance expenses. Staff agreed that the company is entitled to recover these expenses but did not agree that they should be recovered through a cost of equity adjustment. Instead, staff recommended an accounting adjustment of $115,000, an amount which is equal to the company's recorded 1985 issuance expense. The company accepted staff's proposal for purposes of this proceeding.	237

Staff	Description	Revenue Requirement Effect
SG	5. 1986 and 1987 Plant Additions. The stipulated adjustment to average rate base and related depreciation and other expenses is based on the difference between estimated 1986 and 1987 plant additions and the company's 1986 and 1987 budgeted amount. The estimated 1986 plant additions are based on annualizing the cumulative actual construction expenditures for January 1986 through August 1986. The estimated 1987 plant additions are based on the amount budgeted for 1987 in the company's 1986 construction budget adjusted to reflect the 4-year ratio of actual to budget.	(2,988)
SG	6. Production O&M Estimate. The stipulated adjustment to nonlabor, nonfuel production operation and maintenance expense is based on the difference between the company's 1986 budgeted amount and the stipulated estimate. The stipulated estimate is based on an ordinary least-squares analysis using kw as the explanatory variable but substituting the budgeted amount for Colstrip 4, rather than the regression value.	(1,467)
SG	7. Trojan Contract Labor. The stipulated adjustment is based on reducing contract labor at the Trojan Nuclear plant as a result of the company's proposal to hire an additional 65 employes at the site to perform work previously done by contract.	(5,122)
SG	8. Trojan VIC and Recreation. The stipulated adjustment reflects past Commissioners' policy to disallow most of the investment and operating costs of the Trojan visitor information center and recreation area. The policy is based on a determination that, for the most part, these facilities are not used and useful in providing service to PGE's customers.	(783)
SG	9. Customer Advances for Construction. The stipulated adjustment is based on including an estimated amount for customer advances for construction as a reduction in rate base. The estimate is based on the recorded June 30, 1986, amount.	(397)
RC	10. Added Sales for Resale. The company filing excluded nonfirm sales for resale and proposed to include them for Power Cost Adjustment purposes. The stipulation includes $9.5 million of nonfirm sales for resale in base rates.	(9,876)
RC	11. Fuel Inventories. The company filing included a 56.4-day coal supply at the Boardman plant. The stipulated inventory is based on a 45-day supply, largely to reflect the energy surplus.	(300)
EB	12. Added Colstrip 4 Depreciation. In its original filing, PGE calculated 1987 depreciation expense of $8.624 million for Colstrip Unit No. 4. This calculation was based on an estimated composite annual depreciation rate of 3.91 percent. However, the stipulation is based on a composite rate weighted by actual plant investment.	1,237

Staff	Description	Revenue Requirement Effect
EB	13. Added Depreciation on 1987 Additions. In calculating depreciation expense on incremental 1987 additions, PGE used the appropriate dollar additions and proper depreciation rates. However, due to a programming error, the company's model did not accurately perform the calculation of depreciation expense based on average mid-year additions. When depreciation on PGE's estimated 1987 plant in service is calculated properly, 1987 book depreciation expense increases by $960,000.	1,203
TR	14. Holding Company Charges. The company proposed to include $6.4 million of charges to expense arising from transactions with Portland General Corporation, the holding company. The stipulated adjustment reduces the allocation of common costs to PGE by $1.3 million to offer ratepayers some added protection in these affiliated interest cost sharing arrangements.	(1,312)
TR	15. CWDC Property Sale Gains. The company filing excluded all gains on property sales from PGE to its affiliate, Columbia-Willamette Development Co. (CWDC). The stipulated adjustment gives ratepayers some of those gains based on the ratio of depreciation reserve to original cost and the period plant was in service. Gains would be spread over a 3-year period.	(1,687)
TR	16. Station L CWDC Sale and Leaseback. After the company filing, PGE and CWDC entered into a sale and leaseback arrangement for the Station L property. This adjustment includes the effects of the transactions.	(256)
AG	17. Institutional Buildings Program. PGE proposed to recover the expected $2.0 million cost of this mandated conservation program over a 2-year period. The stipulated adjustment would spread the same estimated total cost over a 3-year period.	(364)
AG	18. 6.5% Weatherization Loans. This adjustment includes the interest payable by recipients of these loans as income. Since the loans are included in rate base, failure to include this income would result in an excess recovery of return.	(71)
RL	19. CRPUD Weatherization Loans. The adjustment removes costs arising from loans made to customers in the service area acquired by the Columbia River PUD. The basis for the adjustment is that loans should have transferred to the CRPUD.	(65)
LK	20. RIF Cost Revision. PGE has an on-going Reduction in Force (RIF) program. The company filing includes approximately $674,000 of added costs associated with 29 RIF positions. Based on published articles about PGE's RIF program, staff estimated 79 full-time equivalent positions would be eliminated due to the program during 1986. Total RIF costs associated with the 79 RIF positions were estimated at $1.8 million. Staff recommended this cost be amortized over five years, resulting in a reduction of $333,000 to expenses in 1987. The stipulated adjustment reduces expenses by that amount but includes the unamortized balance in rate base.	(113)

Staff	Description	Revenue Requirement Effect
LK/RL	21. Wage, Salary and Incentive Pay Changes. This adjustment encompasses the following: a. Work Force Reduction. PGE budgeted a work force for 1986 and 1987 based on 3,180 full-time equivalent (FTE) positions, an increase of 106 FTE over 1985 actual work force levels. The stipulated adjustment, based on estimates of positions eliminated through the RIF program and analysis of additional Trojan work force requirements, is a reduction of 97 FTE positions. b. Limited Pay Escalation. The stipulation uses the staff-proposed limit on the rate of pay changes. That limit is based on the application of the change in the Consumer Price Index over the prior three years. c. Equal Sharing. To the extent the limit described in 21.b. produced an adjustment, the stipulation adopts equal sharing between ratepayers and stockholders. This factor recognizes wage and salary progression in the work force. d. Incentive Pay. The stipulation removes all officers' incentive pay but allows rate recovery of one-half the expenses for an incentive pay program applicable to employes in general.	(3,047)
RL	22. Oregon Property Taxes. The company filing included estimates of assessed values and tax rates. The stipulated adjustment uses the actual January 1, 1986, assessed value and known 1985-1986 millage rates for 1986-87 taxes and escalation by 6 percent for 1987/88 taxes.	(1,819)
RL	23. Other Taxes Not Budgeted. The company filing failed to include amounts for Tri-Met Tax, Montana Electric Energy Producers Tax, and Washington Business and Occupation Tax.	760
RL	24. Revised Franchise Fees. The company filing used inappropriate revenue allocation factors to estimate franchise fees. The stipulated adjustment corrects the calculations.	(1,542)
LK	25. Category "C" Advertising. PGE budgeted approximately $1,624,000 for institutional and promotional (Category C) advertising expenses for 1987. Staff proposed allowing 25 percent of the information-related promotional advertising expenses and disallowing the remainder. The company agreed to staff's proposed $1,412,000 reduction to expense.	(1,465)
RL	26. Memberships and Dues. The company filing excluded all memberships and dues except for the Pacific Northwest Utilities Conference Committee (PNUCC). Staff proposed and the stipulation adopts inclusion of 75 percent of the cost of Edison Electric Institute, Northwest Electric Light and Power Association, and PNUCC.	146
RL	27. Revised Interest From ROR Change. The interest deduction for calculating income taxes is based on the weighted cost of debt multiplied by the rate base amount. This adjustment recognizes the revised debt cost per the stipulation as applied to all rate base elements in the PGE filing.	828

Staff	Description	Revenue Requirement Effect
RL	28. Trojan and 1986/87 ITC. During settlement discussions, PGE re-estimated and increased the amount of Investment Tax Credit expected to be generated in 1986 and 1987. But PGE also proposed to recognize an IRS disallowance of $10.8 million of Trojan ITC generated in 1975. The stipulation revises accumulated deferred ITC amounts for these factors.	166
RL	29. Reverse Accelerated Amortization of Deferred Income Taxes. The PGE filing proposed to use an accelerated 7-year amortization of Trojan and Boardman depreciation-related deferred income taxes and of deferred taxes arising from interest capitalized on the books. The stipulation excludes this accelerated amortization, which would have benefitted ratepayers over the next seven years at the expense of those in subsequent years.	28,153
RC	30. SCE Sale. The stipulation includes $7.86 million in revenues from a contract with Southern California Edison Company. The amount used represents six months of revenues since payments begin in July 1987.	(8,153)
LK	31. Revised Load Forecast. PGE's filed revenue forecast is based upon a test year load forecast of 13,556 million kwh sales to customers. Due to lower than expected load growth, actual normalized sales since the UE 48 forecast was developed in November 1985 had been occurring below forecast for the first six months of 1986. PGE's August 1986 revised forecast produced a total decrease in forecast sales of 124.6 million kwh from the original forecast. The stipulated sales level adopts the revised load forecast.	8,281
LK	32. Promotional Activities. PGE budgeted approximately $1,319,000 for promotional activities, excluding promotional advertising expenses during the test year. Staff proposed allowing 25 percent of budgeted expenses for promotional programs which provide information to customers and disallowing the remaining expense. PGE agreed to staff's $990,000 proposed reduction to expense.	(1,027)
RL	33. Correct PGE Boardman Sale Gain Taxes. The company filing proposed to include a portion of the gain on sale of part of the Boardman plant and some transmission facilities as a benefit to ratepayers. This stipulated adjustment reflects the fact that the proposed amortized gain already has been reduced by income taxes on the gain, and test year taxes should not be reduced again.	(9,731)
RL	34. Amortize Nuclear Fuel Negative Salvage. At year-end 1985, PGE had a balance of $27.8 million in a reserve for disposition of nuclear fuel. During 1986 the reserve grew at the rate of $466,000 per month. The reserve is no longer required because the USDOE has assumed responsibility in return for a one-time payment. PGE proposed in UE 47, the Colstrip 4 tracker, to use the excess reserve to offset Colstrip 4's 1986 revenue requirement. The stipulation adopts that proposal. After test year adjustments in UE 47, however, a balance remains in the reserve. This proposed adjustment would reflect amortization of the remaining reserve over three years beginning in April 1987.	(619)

Staff	Description	Revenue Requirement Effect
	Total Stipulated Adjustments	(59,887)
	Revenue Requirement Change Before Contested Adjustments	$ 7,130
	Contested Adjustments per Company.	
	Smurfit Contract. PGE has signed a contract with Smurfit Newsprint Co. to supply energy at reduced rates. PGE would adjust test year revenues to reflect reductions per the contract.	13,329
	Added Revenues Required per Company Before Tax Reform Act of 1986 (TRA)	$20,459
	Effect of TRA per Company	(20,550)
	Added Revenues Required per Company after TRA	$ (91)
	Contested Adjustments per Staff.	
PN/RL	Boardman Sale Gain. PGE's sale of a part of the Boardman plant and some transmission facilities generated a $102.4 million after-tax gain. PGE would give ratepayers about $19.0 million of the gain spread over two years. Staff would give ratepayers $78.7 million of the gain but spread it over 27 years. See testimony.	6,841
LS	Smurfit Contract. PGE has signed a contract with Smurfit Newsprint Co. to supply energy at reduced rates. Staff would adjust test year revenues to reflect the contract rates PGE should have been able to achieve. See testimony.	12,252*
RL/PN	Restore Unamortized Pre-1981 ITC. The company filing removes the benefits of all pre-Economic Recovery Tax Act of 1981 (ERTA) Investment Tax Credits (ITC). Staff would restore all pre-ERTA ITC not already used for rate-making purposes in prior cases. See testimony.	(12,424)
	Added Revenues Required per Staff Before Tax Reform Act of 1986 (TRA)	$13,799
	Effect of TRA per Staff	(27,347)
	Added Revenues Required per Staff after TRA	($13,548)

*The Smurfit contract adjustment has been revised from the stipulation supplied to parties earlier. The revision is based on testimony of Mr. Sparling.

ah/0164H

Staff	Description	Revenue Requirement Effect

Index of Staff Witnesses

EB	Ed Busch
RC	Roger Colburn
SG	Scott Girard
AG	Ann Glaze
MH	Marc Hellman
LK	Lynn Kittilson
RL	Ray Lambeth
PN	Philip Nyegaard
TR	Thomas Riordan
LS	Lee Sparling

ah/0164H

PACIFIC POWER & LIGHT CO.

Staff Issues Summary for Settlement Discussion
UE 52
($000)

Item	Staff	Issue		Revenue Requirement Effect
		Company-calculated added revenues requirement.		$29,563
-/(7)	EB/SG	1. Rate of Return		(164)
		Staff proposes an overall return of 10.35 percent versus the 10.76 percent in the company's filing. Staff proposes to use 1986 year-end cost estimates for debt and preferred, while the company used 1986 average. The year-end estimates are lower. Staff proposes to use an estimated capital structure rather than the capital structure used by the company which was used in the settlement of UE 21. Staff's estimate of cost of common equity is 12.40 percent while PP&L's estimate is 13.20 percent. This adjustment also incorporates the tax effect of staff's lower cost of debt.		
(1)		2. Colstrip 4		
Lns. 3, 8, 9 & 10:	RC	a. Revised Power Costs	187	
		See issue No. 8.		
Ln. 25:	RC	b. Coal Inventory	62	
		Staff proposes to include $367,000 for incremental coal inventory at Colstrip 4. This reflects a 30-day supply at 80 percent C.F. at Colstrip 4. PP&L proposed no additional fuel inventory.		
Ln. 29:	SG	c. Deferred Income Taxes	(68)	
		Staff proposes to use 1987 average balance for the difference between book and tax depreciation rates for 1986 and 1987. The company used one-half of 1987 difference.		
Ln. 30:	SG	d. Deferred ITC	(256)	
		Staff proposes to use the average of the initially deferred ITC and the balance after the first year. The company used one-half of the balance at the end of the first year.		
-	EB	e. Rate of Return	(11)	
		Impact of staff's ROR on the incremental investment.		
		Total		(86)
(2)		3. Jim Bridger #2 Scrubber		
Lns. 3, 8, 9 & 10:	RC	a. Revised Power Costs	(5)	
		See issue No. 8.		

Item	Staff	Issue		Revenue Requirement Effect
Ln. 29:	SG	b. Deferred Income Taxes	(62)	
		See issue No. 2c.		
Ln. 30	SG	c. Deferred ITC	(170)	
		See issue No. 2d.		
-	EB	d. Rate of Return	(11)	
		Impact of staff's ROR on the incremental investment.		
		Total		(248)
(3)		4. Wyodak Scrubber		
Lns. 3, 8, 9 & 10	RC	a. Revised Power Costs	46	
		See issue No. 8.		
Ln. 29:	SG	b. Deferred Income Taxes	(92)	
		See issue No. 2c.		
Ln. 30	SG	c. Deferred ITC	(203)	
		See issue No. 2d.		
-	EB	d. Rate of Return	(9)	
		Impact of staff's ROR on the incremental investment.		
		Total		(258)
(4)	SG	5. Colstrip 4 Deferral		(2,247)
		Staff proposes to base the Colstrip 4 deferral on Order 86-605 which only allowed the deferral from the date of the order, June 23, 1986. The company's filing reflects the deferral from April 15, 1986. The deferral is adjusted to reflect staff's revenue requirement for Colstrip 4.		
(5)	MM	6. PacifiCorp Trans		(1,622)
		Staff proposed disallowance of unauthorized transactions between PP&L and PacifiCorp Trans. The company has not received an affiliated interest order for the electric utility to do business with PacifiCorp Trans. Staff will consider any additional information provided by the company at the settlement conference concerning the cost of these services on a nonaffiliated basis.		

Item	Staff		Issue	Revenue Requirement Effect
(6)	SG	7.	Interest Coordination Staff proposes to adjust income tax to reflect the cost of debt proposed by staff. The impact of this adjustment has been incorporated in the Rate of Return issue.	-0-
(7)	RC	8.	Revised Power Costs Power costs charged to reflect lower QF output and cost, poor market for sales for resale due to low gas prices, and the 300 mw firm intertie capacity granted PP&L by BPA.	(3,267)
			Rounding Error	4
			Total Staff-Proposed Adjustments	$ (7,886)
			Staff-Proposed Revenue Requirement	$ 21,677
			Remove Staff's Revenue Requirement for Wyodak	$ (6,487)
			Staff's Proposed Revenue Requirement - Comparable to Company's Filing of $22.6 M (effective 10/1/86).	$ 15,190
			Adjustments to Staff's Proposed Revenue Requirement as a Result of Settlement Conference.	
	SG	9.	Add Back Revenue Requirement for Wyadak Proposed effective date of rate incrase after in-service date of Wyodak scrubber.	$6,487
	SG	10.	Additional Colstrip 4 Deferral Reflects additional Colstrip 4 deferral from October 1, 1986, to December 31, 1986.	$3,282
	SG	11.	J. Bridger Unit 2 Scrubber Deferral Reflects J. Bridger Unit 2 scrubber deferral from October 1, 1986 to December 31, 1986	$1,961
	MM	12.	Disallow PacifiCorp Trans Revised adjustment to reflect the cost of the services provided to Pacific by its affiliate, PacifiCorp Trans.	$1,417
	RC	13.	Biomass Revised estimate prices paid to Biomass for purchased power.	$(1,146)
	SG	14.	ITC Reverse ITC accounting treatment authorized in the December 20, 1984, singed by Assistant	$(3,714)
			Rounding	(1)

Item	Staff	Issue	Revenue Requirement Effect
		Total Settlement Adjustments	$ 8,286
		Settlement Proposed Increase (Effective 1/1/87)	$23,476
		NOTE: Limited to Company Request of $22,585,00	

Staff Witnesses:

EB	Ed Busch
RC	Roger Colburn
SG	Scott Girard
MM	Mike Myers

ah/7396H

Testimony Before the House

Environment and Energy Committee

on

HB 2145

At Hearing April 8, 1987

Submitted by Richard S. Jarrett, Vice President

CP National Corporation

At hearing March 25, we supported HB 2145, including subsection (5) of section 2, which permits the accruals in deferred accounts approved in the past by the Commissioner to be amortized in rates.

Subsequently, we have been notified by PUC staff that accruals in that account after November 26, 1986, although not yet amortized in rates by CPN, will not be reflected in rates.

For this reason, subsection (5) will permit only partial relief to CPN and we are proposing an amendment (attachment 1) to cure that defect. Why?

First, staff has a point. Subsection (5), read literally, applies only to accruals in authorized deferred accounts. If the account has been subsequently closed, as ours was on November 26, accruals thereafter would not fit the terms of the subsection.

Second, accruals for CPN for QF purchases after November 26 are material to the Company. By April 30, our QF expenses will be $800,000 (3.2% of last year's gross revenues) and will grow at the rate of $170,000 per month thereafter. See attachment 2.

Third, the relief sought by the amendment is narrow. It applies only to expenses from QF purchases. These purchases were mandated by the federal Public Utility Regulatory Policies Act (PURPA) and Oregon's little PURPA, ORS 758.505-.535. The four QF contracts which produce the expense were all approved by the Commissioner. The relief is retrospective only -- for expenses not yet amortized in rates. Future expenses will be handled as the commission directs.

Fourth, CPN is the only utility which was selling its electric territory at the time the controversy over deferrals arose. It is that anticipated sale which has created this singular need for relief from the legislature. The amendment will cure only this anomaly.

Last, unlike the permissive power granted to the commission in subsection (5), CPN's proposed amendment is mandatory on the commission: those described amounts shall be reflected in rates. This is the reason:

We have been informed by PUC staff that even if post-November 26 QF expenses are permitted to be amortized in rates by the legislature, staff will recommend against amortization in rates. Their reasoning -- based upon the premise that CPN should have realized earlier that recovery of post-November 26 QF expenses was in jeopardy and should have applied for earlier relief -- is abstractly defensible but not just.

It is not just because CPN was the only utility in 1986 contemplating sale of its territory; that impending sale led to this problem. Here's what happened.

In December 1985 and January 1986, CPN and the PUC staff knew these things: (1) that CPN's sale to Idaho Power Company had been approved; (2) that consummation of the sale was anticipated in March 1986; (3) that the PUC order approving the sale directed IPC to use its own rates in the old CPN territory, thereby lowering rates, and to refrain from a rate change for one year; (4) that CPN would begin QF purchases under the approved QF contract also in March and that the purchases would increase rates.

To avoid ratepayer confusion by raising rates for CPN's QF expenditures and immediately lowering them for IPC's assumption of the territory, staff recommended that CPN not file a rate case, but keep track of the QF expenses in a balancing account. The Commissioner authorized this by order.

The sale did not close in March, and in fact the Commissioner stayed his approval of the sale pending resolution of certain labor issues. The QF balancing account continued.

By October, the NLRB had ruled in CPN's favor on the labor issue. The sale with Idaho was then contemplated to close by December 31, 1986. Accordingly, we filed to amortize the account through October and for prospective relief through the end of the year. The interim rate order permitted this and closed the QF balancing account. This was fair because staff and CPN contemplated a year-end sale to Idaho Power.

In short, CPN had no reason to apply for prospective relief from March to October because it had a balancing account and because a year-end sale was anticipated. It is 20/20 hindsight to say now that CPN should have avoided regulatory lag by filing earlier for prospective QF rate relief. That relief wasn't needed because of the sale to Idaho Power by December 31.

But the sale didn't close and unamortized post-November 26 QF expenses will reach $800,000 by April 30 and keep growing at the rate of $170,000 per month thereafter. It is not just to make CPN shareholders bear that expense which is required by your own law.

Please note that the amortization we propose, while mandatory on the commission, is subject to reconciliation against authorized earnings under subsection (4) and the limit of annual amortization set by subsection (6) (subsection (7) if our amendment is adopted).

We respectfully urge acceptance of the amendment.

Amendments

to

Hand-engrossed HB 2145

(Representing OPUC Amendments of April 8, 1987)

Proposed by

CP National Corporation

On page 2, after line 6, insert:

"(6) Notwithstanding subsection (5) of this section, utility expenses for electric power purchases incurred under contracts entered into and approved by the commission before the effective date of this 1987 Act pursuant to ORS 758.505 to 758.535 shall be reflected in rates by the commission upon application of the utility to the extent they:

(a) Have accrued in unamortized deferral accounts established by commission order before the effective date of this 1987 Act, or

(b) Represent unamortized power purchases made by the utility before the effective date of this 1987 Act."

On page 2, line 7, delete "(6)" and insert "(7)".

Attachment 1 to CPN
Testimony of 4/8/87

64th OREGON LEGISLATIVE ASSEMBLY–1987 Regular Session

House Bill 2145

Ordered printed by the Speaker pursuant to House Rule 12.00A (5). Presession filed (at the request of Public Utility Commissioner)

SUMMARY

The following summary is not prepared by the sponsors of the measure and is not a part of the body thereof subject to consideration by the Legislative Assembly. It is an editor's brief statement of the essential features of the measure as introduced.

Allows recovery in rates of costs retroactively imposed upon utilities by government agencies. Permits utility rates to include deferred costs.

A BILL FOR AN ACT

Relating to public utilities.

Be It Enacted by the People of the State of Oregon:

SECTION 1. Section 2 of this Act is added to and made a part of ORS chapter 757.

SECTION 2. (1) In addition to powers otherwise vested in the commission, and subject to the limitations contained in subsection (6) of this section, under amortization schedules set by the commission, a rate or rate schedule may reflect the following:

(a) Amounts lawfully imposed retroactively by order of [a] another governmental agency; or

(b) Amounts deferred under subsection (2) of this section.

(2) Upon application of a utility or ratepayer or upon the commission's own motion, and [opportunity for public notice and] after public notice and opportunity for comment, the commission by order may authorize deferral of the following amounts for later incorporation in rates:

(a) Amounts incurred by a utility resulting from changes in the wholesale price of natural gas or electricity, approved by the Federal Energy Regulatory Commission;

(b) Balances resulting from the administration of Section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act of 1980; or

(c) [Amounts incurred by a] Utility expenses or revenues, the recovery or refund of which the commission finds should be deferred in order to minimize the frequency of rate changes or the fluctuation of rate levels or to match appropriately the costs [and benefits received by rate payers; or

(d) Amounts to the extent they have accrued in deferred accounts with commission authorization prior to the effective date of this 1987 Act.] borne by and benefits received by ratepayers.

(3) The commission may authorize deferrals under subsection (2) of this section beginning with the date of application, together with interest established by the commission."

[(3)] (4) Unless subject to an automatic adjustment clause under ORS 757.210 (1), amounts described in this section shall be allowed in rates only to the extent authorized by the commission [upon application by a utility.] in a proceeding to change rates under ORS 757.210 and upon review of the utility's earnings at the time of application to amortize the deferral.

"(5) Amounts that have accrued in deferred accounts with commission authorization before the effective date of this 1987 Act also may be reflected in rates. However, in order to continue to use such accounts the public utility shall apply for authorization of the commission under subsection (2) of this section.

"(6) Notwithstanding subsection (5) of this section, utility expenses for electric power purchases incurred under contracts entered into and approved by the commission before the effective date of this 1987 Act pursuant to ORS 758.505 to 758.535 shall be reflected in rates by the commission upon application of the utility to the extent they:

(a) Have accrued in unamortized deferral accounts established by commission order before the effective date of this 1987 Act, or

(b) Represent unamortized power purchases made by the utility before the effective date of this 1987 Act."

["(6)] (7) **In any one year, the overall average rate impact of the amortizations authorized under this section shall not exceed three percent of the utility's gross revenues for the preceding calendar year.".**

CP National
Oregon Electric District
Co-Gen Balance Account
Calcualation of Estimated Balance Ending June 1987

Month (A)	SUPPLIER (B)	Co-Gen rate (C)	IPC rate (D)	Rate Diff (E) (C)-(D)	Co-Gen Kwhr Billed (F)	Co-Gen Base Purchased (G)	Diff KWhr (H) (F)-(G)	Bal Acc Deferral (I) (E)X(H)	Bal B4 Interest (J) (M)+(I)	Interest Rate (K)	Interest (L) (J)X(K)	Ending Balance (M) (L)+(J)
Nov 26-30/86 (Pro-rated)	City of Cove	0.061500	0.018339	.043161	110,880	208,333	-97,453	-$701.03				
	I V L P (Crisstad)	0.061500	0.01833	.043161	2,191,058	1,971,000	220,058	1,582.98				
	Blue Mt. Forest	0.063970	0.018339	.045631	3,202,260	1,916,250	1,286,010	9,780.28				
	CO-GEN CO	0.062171	0.018339	.043832	5,881,800	4,106,250	1,775,550	12,970.93	$23,633.16	6.46%	$127.23	$23,760.39
December 86	City of Cove	0.061500	0.018339	.043161	103,680	208,333	-104,653	-4,516.93				
	I V L P (Crisstad)	0.061500	0.018339	.043161	1,435,370	1,971,000	-535,630	-23,118.33				
	Blue Mt. Forest	0.063970	0.018339	.045631	2,799,171	1,916,250	882,921	40,288.57				
	CO-GEN CO	0.062171	0.018339	.043832	6,109,400	4,106,250	2,003,150	87,802.07	$124,215.77	6.95%	$719.42	$124,935.19
Jan 87 (Purchases Vs Base)	City of Cove	0.061500	0.018339	.043161	61,920	208,333	-146,413	-6,319.33				
	I V L P (Crisstad)	0.061500	0.018339	.043161	2,982,430	1,971,000	1,011,430	43,654.33				
	Blue Mt. Forest	0.063970	0.018339	.045631	2,894,959	1,916,250	978,709	44,659.47				
	CO-GEN CO	0.062171	0.018339	.043832	5,801,300	4,106,250	1,695,050	74,297.43				
(New/Old Co-gen Rate Diff)	City of Cove	0.063890	0.061500	.00239	61,920		61,920	147.99				
	I V L P (Crisstad)	0.063890	0.061500	.00239	2,982,430		2,982,430	7,128.01				
	Blue Mt. Forest	0.066500	0.063970	.00253	2,894,959		2,894,959	7,324.25				
	CO-GEN CO	0.064696	0.062171	.002525	5,801,300		5,801,300	14,648.28	$310,475.62	7.03%	$1,818.87	$312,294.49
February (Purchases Vs Base)	City of Cove	0.061500	0.018339	.043161	93,600	208,333	-114,733	-4,951.99				
	I V L P (Crisstad)	0.061500	0.018339	.043161	2,834,490	1,971,000	863,490	37,269.09				
	Blue Mt. Forest	0.063970	0.018339	.045631	2,859,169	1,916,250	942,919	43,026.34				
	CO-GEN CO	0.062171	0.018339	.043832	5,813,900	4,106,250	1,707,650	74,849.71				
(New/Old Co-gen Rate Diff)	City of Cove	0.063890	0.061500	.00239	93,600		93,600	223.7				
	I V L P (Crisstad)	0.063890	0.061500	.00239	2,834,490		2,834,490	6,774.43				
	Blue Mt. Forest	0.066500	0.063970	.00253	2,859,169		2,859,169	7,233.7				
	CO-GEN CO	0.064696	0.062171	.002525	5,813,900		5,813,900	14,680.1	$491,399.57	7.07%	$2,895.16	$494,294.73
March (Purchases Vs Base)	City of Cove	0.061500	0.018339	.043161	208,333	208,333	0	0				
	I V L P (Crisstad)	0.061500	0.018339	.043161	3,942,000	1,971,000	1,971,000	85,070.33				
	Blue Mt. Forest	0.063970	0.018339	.045631	2,554,635	1,916,250	638,385	29,130.15				
	CO-GEN CO	0.062171	0.018339	.043832	4,653,750	4,106,250	547,500	23,998.02				
(New/Old Co-gen Rate Diff)	City of Cove	0.063890	0.061500	.00239	208,333		208,333	497.92				
	I V L P (Crisstad)	0.063890	0.061500	.00239	3,942,000		3,942,000	9,421.38				
	Blue Mt. Forest	0.066500	0.063970	.00253	2,554,635		2,554,635	6,463.23				
	CO-GEN CO	0.064696	0.062171	.002525	4,653,750		4,653,750	11,750.72	$660,626.48	7.07%	$3,892.19	$664,518.67
April (Purchases Vs Base)	City of Cove	0.061500	0.018339	.043161	208,333	208,333	0	0				
	I V L P (Crisstad)	0.061500	0.018339	.043161	3,942,000	1,971,000	1,971,000	85,070.33				
	Blue Mt. Forest	0.063970	0.018339	.045631	2,554,635	1,916,250	638,385	29,130.15				
	CO-GEN CO	0.062171	0.018339	.043832	4,653,750	4,106,250	547,500	23,998.02				
(New/Old Co-gen Rate Diff)	City of Cove	0.063890	0.061500	.00239	208,333		208,333	497.92				
	I V L P (Crisstad)	0.063890	0.061500	.00239	3,942,000		3,942,000	9,421.38				
	Blue Mt. Forest	0.066500	0.063970	.00253	2,554,635		2,554,635	6,463.23				
	CO-GEN CO	0.064696	0.062171	.002525	4,653,750		4,653,750	11,750.72	$830,850.42	7.07%	$4,895.09	$835,745.51
May (Purchases Vs Base)	City of Cove	0.061500	0.018339	.043161	208,333	208,333	0	0				
	I V L P (Crisstad)	0.061500	0.018339	.043161	3,942,000	1,971,000	1,971,000	85,070.33				
	Blue Mt. Forest	0.063970	0.018339	.045631	2,554,635	1,916,250	638,385	29,130.15				
	CO-GEN CO	0.062171	0.018339	.043832	4,653,750	4,106,250	547,500	23,998.02				
(New/Old Co-gen Rate Diff)	City of Cove	0.063890	0.061500	.00239	208,333		208,333	497.92				
	I V L P (Crisstad)	0.063890	0.061500	.00239	3,942,000		3,942,000	9,421.38				
	Blue Mt. Forest	0.066500	0.063970	.00253	2,554,635		2,554,635	6,463.23				
	CO-GEN CO	0.064696	0.062171	.002525	4,653,750		4,653,750	11,750.72	$1,002,077.26	6.46%	$5,394.52	$1,007,471.78
June (Purchases Vs Base)	City of Cove	0.061500	0.018339	.043161	208,333	208,333	0	0				
	I V L P (Crisstad)	0.061500	0.018339	.043161	3,942,000	1,971,000	1,971,000	85,070.33				
	Blue Mt. Forest	0.063970	0.018339	.045631	2,554,635	1,916,250	638,385	29,130.15				
	CO-GEN CO	0.062171	0.018339	.043832	4,653,750	4,106,250	547,500	23,998.02				
(New/Old Co-gen Rate Diff)	City of Cove	0.063890	0.061500	.00239	208,333		208,333	497.92				
	[illegible] L P (Crisstad)	0.063890	0.061500	.00239	3,942,000		3,942,0[illegible]	9,421.38				
	[illegible]e Mt. Forest	0.066500	0.063970	.00253	2,554,635		2,554,[illegible]	6,463.23				
	[illegible]GEN CO	0.064696	0.062171	.002525	4,653,750		4,653,[illegible]	11,750.72	$1,173,803.53	6.46%	$6,318.98	$1,180,122.51

Attachment 2 to CPN
Testimony of 4/8/87

129 MOTION: SEN. SIMMONS moved that the HB 2660A-6 amendments dated 4/28/87 BE ADOPTED.

133 VOTE: CHAIRMAN HILL, hearing no objection to the motion, declared the amendments ADOPTED. Sen.Cohen was EXCUSED.

135 MOTION: SEN. SIMMONS moved that HB 2660 A-Eng., as amended, be sent to the Floor of the Senate with a DO PASS recommendation.

137 VOTE: The committee assistant called the roll with all members present voting AYE. Sen. Cohen was EXCUSED.

140 CHAIRMAN HILL declared the motion CARRIED.

140 SEN. SIMMONS will lead discussion on the Floor.

SEN. SIMMONS left the meeting at 2:30 p.m.

HOUSE BILL 2145 A-ENG. - RELATING TO PUBLIC UTILITIES

154 REP. RON EACHUS stated HB 2145 comes from the Energy and Environment Committee in the House. It is an out growth of changes needed in response to an Attorney General's Opinion and tried to address the needs of the Public Utility Commission and the needs of the utilities that were affected by it as well as some of the problems and process that were raised by the public interest intervenors and participants in the rate making proceedings. There is a practice called establishing of deferred accounts. The Attorney General determined that there was no specific authority to do that. Generally rates are set on a perspective rate base. Deferred accounts is a retroactive procedure and the Attorney General said there is no specific authority to do that. This bill provides that specific authority. The goals were to limit it and make sure it was applied in out-of-the ordinary circumstances, applied on a temporary basis and applied where generally small amounts are in effect. The concerns that were raised in their Committee were that deferred accounts usually were applied when there was a request by a utility, also that while there was existing authority for interim rate increases, there was not existing authority for interim rate decreases. They have allowed for the rate payer or upon the Commission's own motion, to authorize deferral of certain amounts which would include benefits to the rate payers. The bill specifically allows deferral of accounts, deferred accounts be the amounts that are incurred by a utility resulting from changes in the wholesale price of natural gas or electricity approved by the Federal Energy Regulatory Commission, balances resulting from administration of the Pacific Northwest Power Planning and Conservation Act and utility expenses or revenue

recovery and they have added "or refund" of which the Commission finds should be deferred in order to minimize the frequency of rate changes or the fluctuation of rate levels to match appropriately the costs borne by all the benefits received by the rate payers. They have allowed deferred accounts in certain circumstances and they have established a process that is balanced. It allows either the Commission or the rate payers to initiate the deferral. The other question was what to do with the deferred accounts that have been declared illegal. Section 5 provides a method for that.

180 SEN. FRYE left the meeting at 2:30.

230 SEN. COHEN returned at 2:35.

235 BILL WARREN, Assistant Commissioner for the Utility Program with the PUC, stated they have distributed testimony from Commissioner Davis (SEE EXHIBIT D). The testimony describes what Rep. Eachus mentioned. They have also appended to the testimony the Attorney General's Opinion of March 18, 1987 which Rep. Eachus referred to, and a listing of the deferred accounts that are in effect currently that would be grandfathered under Section 25 of the bill.

250 SEN. COHEN said she was nervous about this bill and asked why are we grandfathering people.

257 REP. EACHUS said they are being grandfathered because they had deferred accounts.

280 BILL WARREN stated the reason the grandfathering provision is in the bill is that all the transactions listed in the second attachment to the testimony were done in good faith over a period of time during the last several years. There are deferred accounts that would amount to rate increases ultimately and here are substantial amounts of money that would amount to rate decreases for customers of utilities. The Attorney General's Opinion wasn't issued until March 18 of this year. Therefore, they are kind of caught in midstream. These transactions were initially done in good faith and they think it is appropriate to grandfather them because there have been commitments made.

297 SEN. COHEN asked why not grandfather the existing accounts and stop the practice right now.

298 MR. WARREN stated the practice is a good one. They use the practice in a balanced way.

313 SEN. COHEN asked if they have a prevention that stops it from being used in an unbalanced way.

313 MR. WARREN stated yes they do. It is Section 2 (2) of the bill.

326 SEN. COHEN asked how a customer would know there is a deferred account.

324 JOHN SOKOLOWSKY, Assistant Attorney General representing the Public Utility Commission, stated this deferred accounting practice grew up over the last four to eight years, or maybe even longer. No member of the general public knew when a deferred accounting practice was being engaged in. The staff members knew and the utility knew. This legislation in effect grandfathers the existing deferred accounts and starts from zero. No more deferred accounting is allowed except on special application to the PUC in public and a granting of the deferred accounting practice by the Commission itself in a public meeting. Deferred accounting is authorized, but the rates aren't entitled to go up or down. At the time the utility requests it or at the next rate case, application is made to amortize these deferred accounts. Then the utility's earnings are reviewed and only then is the amortization or any part of it allowed. It has not been modified, it has been brought open to the public's examination and probably will not be as extensive as it was in the past because of the mechanism that has to be gone through before it is allowed at all.

400 SEN. SIMMONS returned at 2:40.

TAPE 100, SIDE B

007 SEN. COHEN asked if it will cause trauma and chaos if we put a time limit on this bill.

009 REP. EACHUS stated they did not see a need for a time limit partly because some of the other provisions in the bill and partly because of the balanced approach that is in the bill.

122 REP. EACHUS stated he would like to suggest an amendment. It would add a (7) to Section 2 of the bill. It would state "The provisions of this Act do not apply to telecommunication public utilities." When they focused on the bill the discussions were all focused on energy and not seen necessary to apply to telecommunication utilities. They did not discuss that in the House Committee.

150 CHAIRMAN HILL requested that the amendments be submitted prior to the meeting the next Tuesday.

SENATE BILL 664 - RELATING TO MOTOR FUEL FRANCHISES

169 CHAIRMAN HILL stated there have been amendments offered by various parties. He asked that each person having submitted amendments explain their amendments.

HB 2145 WORK SESSION

395 **ADMINISTRATOR NUSS** gave a brief review of the bill.

432 **MOTION:** **SEN. SIMMONS** moved the -5 amendments.

VOTE: The motion passed without any objections.

451 **MOTION:** **SEN. COHEN** moved to insert after page 1 line 21 "deferrals may be authorized for a period not to exceed 12 months from the date of application".

DISCUSSION: **SEN. COHEN** said she talked with Rep. Ron Eachus and he believed the intention was not to exceed one year.

TAPE 123, SIDE B

040 **SEN. COHEN** said the PUC did not feel this amendment was objectionable.

SEN. KENNEMER asked Sen. Cohen if 12 months was a realistic time frame. **SEN. COHEN** said yes.

VOTE: The motion passed without any objections.

077 **MOTION:** **SEN. SIMMONS** moved HB 2145 to the floor with a Do Pass as amended recommendation.

VOTE: The motion failed with Senators Kennemer and Simmons being the two NAY votes. Sen. Frye was excused.

088 **CHAIR HILL** sent for Sen. Frye to cast the deciding vote.

120 **ROY HEMMINGWAY,** Boise Cascade, said that this bill came about due to a ruling by the Attorney General that stated deferred accounting and retroactive rate making are practices not authorized by Oregon law. The bill was necessary to make the practice available in the future. He had asked the House to add an amendment that said the deferred accounts in the past could be amortized in the future but could only have a rate impact of 3% per year. He added that had impacted 3 utilities in the Northwest. Those were CP National, Portland General Electric and Idaho Power. He said that Boise Cascade was concerned with CP National's rates in Eastern Oregon. He felt CP National should be subjected to the 3% rate as opposed to the 7.5% rate they were currently using.

172 **SEN. COHEN** asked how close this would be to putting CP National under. **MR. HEMMINGWAY** said it was not close at all.

200 **JOHN POWELL,** CP National, said he had spoken with Rep. Eachus and he felt that the amendment and the original HB 2145 struck a balance and he would oppose the additional amendment proposed by Boise Cascade.

226 **RAY LAMBETH,** PUC, said he thought they had an agreement on the bill with the 3% limitation. **CHAIR HILL** asked Mr. Lambeth if anything had been raised that

would make the commission change their mind about the bill. **MR. LAMBETH** said the bill was in re-examination of amortizations and deferred accounts that were in existence.

260 **CHAIR HILL** asked Mr. Lambeth what he would like from the committee at that time. **MR. LAMBETH** asked for 5 minutes to review the amendments and to contact someone at the Commission.

280 **MOTION:** **CHAIR HILL** moved to insert the contents of SB 708 be amended to HB 2145.

VOTE: The motion passed with Senators Kennemer and Simmons being the two NAY votes.

SB 642 PUBLIC HEARING AND WORK SESSION

315 **PAUL ROMAINE,** National Vehicle Leasing Association, said the bill would deal with the problem of when people entered into what they presumed to be a lease and then it turned out to be something else like a retail installment contract or a time contract and they would be subject to different disclosure requirements than they originally entered into. He referred the committee to a letter from MILLER-NASH. (EXHIBIT I). He then went through the bill section by section and noted the changes. (EXHIBIT J). He then reviewed the bill.

420 **SEN. KENNEMER** noted that on page 4 of the bill, the number 3 should be deleted and replaced with 2, and that number 4 should be deleted and replaced with 3.

427 **MOTION:** **SEN. KENNEMER** moved said language.

VOTE: The motion passed without any objections.

435 **MOTION:** **CHAIR HILL** moved the hand-engrossed version of the amendments for SB 642.

DISCUSSION: **SEN. SIMMONS** asked what the amendment in the margin of page 3 meant. **MR. ROMAINE** referred the committee to page 2 of the bill and the definition of retail installment contract.

TAPE 124, SIDE A

VOTE: The motion passed without any objections.

030 **MOTION:** **SEN. KENNEMER** moved SB 642 to the floor with a Do Pass as amended recommendation.

VOTE: The motion passed with all members present voting AYE. Sen. Frye was excused. Sen. Simmons will carry the bill.

HB 2145 WORK SESSION CONTINUED

045 **MR. LAMBETH** stated he had not been able to reach the Commission. He said he had spoken to Mr. Hemmingway from Boise Cascade. He said they wanted to make the 3% limitation retroactive to November 15, 1986. He felt the Commission would endorse the amendment in that form.

TAPE 124A

060 **SEN. COHEN** said she was concerned with how the whole thing would "play out". She then asked for Mr. Powell to step back up to the witness table and explain the impact on CP National for the committee.

080 **MR. POWELL** said he was retained after the bill had passed the House. He said rate cases are not resolved overnight. He felt the representative from the PUC would be more capable in answering the question.

107 **MR. LAMBETH** said the effect on CP National would be to require a refund of some money that they have collected since November 26, 1986. He added there was an interim rate increase and those rates are always subject to refund. He noted that the 3% limit would be used.

124 **SEN. COHEN** asked when he expected the rate order to go into effect and if it would be retroactive. **MR. LAMBETH** said that CP National would not stand to lose any money from this bill.

145 **CHAIR HILL** said the thing that made him uncomfortable was that the last time they were talking about a clean bill and now he was not sure of the effect of the bill in light of Sen. Cohen's amendment. He would like Mr. Lambeth to go back to the proponents of the bill and get some agreement.

175 **MR. POWELL** asked for a certain time so they would be forced to work on it. **CHAIR HILL** gave them until the next meeting.

HB 2707 PUBLIC HEARING AND WORK SESSION

190 **BRAD MORRIS,** Oregon Association of Realtors, also represented the Oregon League of Financial Institutions and the Oregon Bankers Association, spoke in favor of the bill. He said the bill would repeal (2) of ORS 86.710 to permit financial institutions to provide conventional financing for those properties. He added there was no opposition to the bill and no amendments.

212 **MOTION:** **SEN. COHEN** moved HB 2707 to the floor with a Do Pass recommendation.

DISCUSSION: SEN. KENNEMER asked if there was any mention in the bill of EFU land that had not been used. **MR. MORRIS** said that new language had been put in the bill.

VOTE: The motion passed with all members present voting AYE. Senators Frye and Simmons were excused. Sen. Cohen will carry the bill.

HB 2398 PUBLIC HEARING AND WORK SESSION

234 **HARDY CAVE,** AARP, said he opposed the bill in the current form. He said that some of the insurance companies were granting a 10% rate reduction to seniors with safe driving records.

260 **RAY GRIBLING,** Pacific Northwest Bell, asked about the committees amendments to HB 2145 which included the language on intervenor funding.

DISCUSSION: **SEN. KENNEMER** said that after further thought on the bill he did not think he could support the bill.

VOTE: The motion passed without any objections and the bill failed.

HB 2145 WORK SESSION

444 **ADMINISTRATOR NUSS** reviewed the -6 amendments.

454 **CHAIR HILL** explained what had already been adopted by the committee. He added the only issue left to discuss was the amendments proposed by Boise Cascade.

490 **SEN. COHEN** noted the committee had not passed the portion of the -6 amendments found on page 2 lines 5-11.

TAPE 127, SIDE A

024 **MOTION:** **CHAIR HILL** moved to delete the Boise Cascade amendment as they are contained in the -6 amendments on lines 5-11.

035 **ALLAN WILLIS,** Boise Cascade, withdrew the Boise Cascade amendments.

050 **CHAIR HILL** anounced the committee would be at ease.

HB 2145 WORK SESSION

135 **CHAIR HILL** explained to Sen. Frye where they were with the bill.

147 **MOTION:** **CHAIR HILL** moved HB 2145 to the floor with a Do Pass as amended recommendation.

VOTE: The motion passed with Senators Kennemer and Simmons voting NAY. Senator Kennemer served notice of a minority report on the bill. Chair Hill will carry the bill.

165 **SEN. SIMMONS** asked Dave Barrows if he had seen HB 2300.

170 **DAVE BARROWS,** Oregon League of Financial Institutions, said he had some involvement with the bill on the House side. He then referred the committee to the House staff Measure analysis. (EXHIBIT N). He said the bill would be an important consumer safe-guard.

224 **MOTION:** **SEN. SIMMONS** moved HB 2300 to the floor with a Do Pass recommendation.

VOTE: The motion passed with all members present voting AYE. Senators Frye and Kennemer were excused. Sen. Simmons will carry the bill.

SB 696 PUBLIC HEARING AND WORK SESSION

238 **SEN. JOHN BRENNEMAN,** District 2, explained to the committee some of the claims that had been filed and the unfair discriminatory practice. He added tha claims were not against the drivers but were filed if someone using the transportation fell and broke a hip while disembarking. THe amendments he

SENATE BUSINESS, HOUSING AND FINANCE
Bill No. 2145 D Pages 5 Z Date MAY 21 1987 Rep Eachus/P.U.C

BEFORE THE SENATE BUSINESS,
HOUSING & FINANCE COMMITTEE

HOUSE BILL 2145

Testimony of Charles Davis
Oregon Public Utility Commissioner May 21, 1987

Background

To explain the reasons for this legislation, it is first necessary to describe some principles used in setting utility rates.

Utility rates are set for the future. All rates now in effect are based on expectations of utility company expense for this period. Those expectations were based on facts presented at the time the Commissioner set rates. As with any forecast, those expectations of the future can never be exactly correct. Whether or not a utility has net earnings during the time today's rates are in effect, the utility cannot ask for an increase in rates to make up past losses or improve past earnings.

If in looking to the future the utility expects its present rates will not cover its expenses and provide a reasonable rate of return for its investors, it may apply to the Commission for authorization to increase its rates. In doing so, its proof of need is based on its future expectations.

There are a few circumstances in which expenses unanticipated at the time rates were approved by the Commissioner would have been included in rates had the Commissioner known of them. These often are the result of governmental action. In part, that's what HB 2145 seeks to address. For example, the Oregon Legislature mandated certain weatherization programs. Since the expense of these programs to the utilities could not be predicted accurately, the Public Utility Commissioner authorized the companies to accumulate those costs for a time before rates were increased to recover them.

Similarly, the Nuclear Regulatory Commission has on prior occasions reduced the cost to Portland General Electric for processing spent fuel from Trojan. PGE, therefore, had collected more from its customers, for this purpose, than it would need. The management of PGE did not achieve these savings by superior management. The company realized the savings as the result of governmental action.

In all these instances, it is not a question of <u>whether</u> the changes in revenue or in expense resulting from government action will be included in rates charged for service, it is a question of <u>when</u> that should begin. It would be almost impossible to conduct a utility rate review each time these mandated changes occur. Hence, it has seemed reasonable to defer consideration of these governmentally imposed reductions or increases in expense to the next formal review of all expenses to be incurred by the utility in providing service.

There is a rule of law that utility rates may not be made retroactively in absence of express statutory authority. This rule prohibits a utility from recovering past costs in future rates and prohibits a regulator from taking a utility's past profits, lawfully earned.

From the customer's viewpoint, the principle underlying the prohibition against retroactive ratemaking is that the customer should know what a utility service costs him at the time he takes it. The posted tariff on the day of service represents a contract between the customer and the utility. The customer should not expect to pay more and the utility should not expect to get less. To the extent past costs are reflected in future rates or past utility profits are taken away in future rates, they benefit or burden future purchasers of the service (not necessarily the same ones who caused the cost) and compromise this principle.

<u>HB 2145</u>

This measure is designed to allow the Commission to make rates retroactively in certain situations. Generally speaking, it allows the Commission to include in rates those costs which have been imposed retroactively upon a utility by another governmental agency and which the utility therefore had no opportunity to predict in a rate proceeding. In such case, the utility could not have increased its rates in anticipation of the retroactive levy.

Secondly, the proposed measure allows the Commission to make rates retroactively in cases where the utility asks that a cost be deferred or the Commission believes income amounts should be deferred and not reflected in rates until a later date. A rate-making delay may be preferable either because (a) the full extent of the costs, that is, the net cost, will not be known until a future time, or (b) a rate change, otherwise authorized, should be matched with other costs or benefits or matched in time with other rate changes.

In both of these situations, if the amounts in question are later amortized in rates, the rates are said to be made retroactively because they reflect recovery of expenses or income already incurred by the utility, as opposed to amounts expected in the future. However, I believe that there are instances in which retroactively made rates are in the public interest. HB 2145 gives the Commission the authority to make retroactive rates in these instances.

The Attorney General's Office has advised the Public Utility Commission that current statutes do not allow the deferral of ratemaking to accommodate many of these changes in expense or income between formal rate proceedings. Attachment 1 is a copy of the Attorney General's Opinion, issued March 18, 1987.

In my judgment, the practice of deferred recognition for some kinds of transactions is appropriate. HB 2145 would give the Commission explicit authority to follow this practice. Attachment 2 is a listing of deferred accounts as of December 31, 1986. The listing shows the variety of circumstances under which deferred accounts have been created. HB 2145 would establish the conditions for future rate recognition of these deferrals as well as for creation of new deferred accounts and eventual rate treatment.

My staff has discussed HB 2145 with all known interested parties, including representatives of regulated utilities, industrial customers, and consumer groups. The engrossed House Bill results in part from those discussions as well as from continuing review by the Attorney General's office.

Section-by-Section Analysis

The bill specifies the circumstances under which deferred amounts may be allowed. The provisions of the bill are permissive, not mandatory. The PUC may authorize deferrals, but is not required to. Public notice is required. The Commission will assess the reasonableness of deferral by requesting public comment before the deferral is allowed. (Section 2(2)) The only exception to the notice requirement is where a governmental body imposes amounts retroactively.

All parties and ratepayers are protected by the requirement that general rate case procedures be used before rates are changed to include deferred amounts. (Sec. 2(4)) Those procedures include notice to all parties, filing of evidence by the utility, and hearings if requested. Section 2(4) also requires a review of the utility's earnings at the time of application. The earnings review will allow the Commission to determine whether amortization of deferred income or expense amounts is warranted based on the utility's earnings; if earnings are higher than authorized, expense amortization through rates will not be appropriate.

An additional safeguard is provided by Section 2(3). To encourage timely action by utilities, deferrals may begin no earlier than the date of application. If an increased expense level begins in January, but an application is not made until July, the January through June increases in costs must be absorbed by the company.

Section 2(6) represents a final protection for ratepayers. The section provides a 3 percent cap on the sum of all amortizations in any one year. The provision should serve to prevent rate shock from deferrals.

Some examples of the types of situations covered by the bill may be useful. I will present them in the order in which they appear in the bill.

Sec. 2(1)(a) Amounts lawfully imposed retroactively by order of another governmental agency.

Retroactive tax increases would be covered by this provision. Although not common, there have been occasions when this has occurred. In recent years there have been special property tax assessments, and the Federal Tax Reform Act of 1986 disallowed use of most investment tax credits retroactive to the first of the year. If these amounts are material, recovery in rates could be permitted.

Sec. 2(2)(a) Amounts incurred by a utility resulting from changes in the wholesale price of natural gas or electricity approved by the Federal Energy Regulatory Commission (FERC).

The FERC has responsibility for setting wholesale natural gas and electricity rates. Particularly for gas distribution companies, these costs may be quite significant. This subsection would allow deferral if necessary to match up both refunds and cost increases with the timing of a general rate change or to coordinate with other income or expense changes.

Sec. 2(2)(b) Balances resulting from administration of Section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act of 1980 (Regional Act).

The Regional Act established a mechanism through which residential and certain other customers of investor-owned electric utilities (IOU's) were to get benefits associated with the federal hydroelectricity system. The Bonneville Power Administration (BPA) administers the process. IOU's file with the BPA on behalf of eligible customers and pass the benefits on through regular billings. The BPA has frequently adjusted the amounts payable to IOU's. The PUC has authorized a deferral mechanism to assure that ratepayers get the appropriate benefit as finally settled. This subsection would authorize continued use of this "true-up" procedure.

Sec. 2(2)(c) Amounts incurred by a utility which the Commission finds should be deferred in order to minimize the frequency of rate changes, or the fluctuation of rate levels, or to match the costs borne and benefits received by ratepayers.

This subsection covers the many occasions when a legitimate ratemaking income or expense item is changing and the PUC believes rates should be adjusted as a result, but finds that rate changes should take place at some subsequent time.

For example, expense reductions might occur in thesecond quarter of a year, but it is known at the time that an expense increase, perhaps a wholesale rate change, will occur in the fourth quarter of the year. To avoid a rate decrease followed in short order by a rate increase, it may be preferable to accumulate the expense decreases and use them to offset, in whole or in part, the subsequent expense increase.

We currently have an example of such a situation. The Tax Reform Act of 1986 reduces Pacific Power & Light Company's federal income tax charges for 1987. Rates could be reduced early in 1987 for this change. But the BPA has filed notice of an expected rate increase effective October 1, 1987. It could be appropriate to defer and accumulate certain of the benefits arising from the tax expense decreases, with interest, and use them to offset BPA-related cost increases.

The subsection also refers to permitting deferrals to match costs and benefits. Considerations of this type led to spreading costs of weatherization programs over a ten-year period. The reasoning was that weatherization measures would produce benefits lasting for some time. It seemed inappropriate to charge costs only to ratepayers at the time the weatherization expenses were incurred.

Section 2(5) provides authorization for completion of amortizations begun, continued deferral of amounts already existing, and continued use of accounts authorized as of the effective date of the bill. To the extent rate action has not already been ordered, however, we intend to apply the procedures embodied in Section 2(4). In addition, utilities will have to apply for reauthorization of existing accounts. Public notice will be required and hearings will be held at the request of any interested party.

This legislation would clarify the authority of the Commission to use deferred accounting when it is deemed by the Commission to be in the public interest to do so.

I urge your adoption of HB 2145.

Jack Socolofsky from the Attorney General's office and Bill Warren from my staff are here to assist in answering questions you may have.

ah/1123H

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March 18, 1987

Charles Davis
Public Utility Commissioner
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Re: Opinion Request OP-6076

Dear Mr. Davis:

You ask whether you may issue four orders that implicate the rule against retroactive ratemaking. We conclude that retroactive ratemaking orders are absolutely impermissible unless they are expressly authorized by the legislature and do not violate the Oregon and United States Constitutions.

Each of the orders you propose violates the rule against retroactive ratemaking. The orders you propose that would create balancing accounts to adjust for power costs would not violate the rule if the legislature authorizes the Public Utility Commissioner (commissioner) to include "cost of service" adjustment clauses in utility tariffs.

This opinion is in two parts. Part I explains the rule against retroactive ratemaking and its origins. Part II applies that rule to each of the orders you propose.

PART I

The Rule Against Retroactive Ratemaking.

Retroactive ratemaking is

> "the setting of rates which permit a utility to recover past losses or which require it to refund past excess profits collected under a rate that did not perfectly match expenses plus rate-of-return with the rate actually established." State ex rel Util. Consumers Council v. P.S.C., 585 SW2d 41, 59 (Mo 1979) (hereafter Consumers Council)[1]

See Board of Commrs. v. N.Y. Tel. Co., 271 US 23, 31, 46 S Ct 363, 70 L Ed 808 (1926) (hereafter NY Tel).

Another court stated the rule slightly differently:

"Technically, retroactive rate making occurs when an additional charge is made for past use of utility service, or the utility is required to refund revenues collected, pursuant to then lawfully established rates, for such past use.

"* * * * *

"* * * Prospective rate making to recover unexpected past expense, or to refund expected past expense which did not materialize, is as improper as is retroactive rate making." State ex rel Utilities Com'n. v. Edmisten, 291 NC 451, 232 SE2d 184, 194-95 (1977).

However the rule is stated, it applies when past profits or losses, including past expenses, are incorporated in future rates. The rule is not in issue when the regulator employs a past "test year" to predict future expenses and rate base.[2] The rule is implicated when the regulator, after determining expected costs and revenues, supplements that determination by employing past profits or losses in setting the future return the utility will be authorized to earn.

Although Oregon courts never have addressed the question, the rule against retroactive ratemaking has been adopted by the highest court of every jurisdiction in the United States that has considered the issue.[3]

Strong policy considerations support the rule against retroactive ratemaking:

"The rule against retroactive ratemaking serves two basic functions. Initially, it protects the public by ensuring that present consumers will not be required to pay for past deficits of the company in their future payments. The Supreme Court of New Jersey has expressed this legitimate concern as follows:

"'The present practice, as set forth in these cases, is fair to the public utility, for it can act as speedily as it sees fit to move for a correction of inadequate rates, and it is fair to the consumer in safe-

> guarding him from surprise surcharges dating back over years that he had a right to assume were finished business for him and possibly over years when he was not even a consumer.' New Jersey Power & Light Co. v. State Department of Public Utilities, Board of Public Utility Comm'rs, 15 N.J. 82, 93, 104 A.2d 1, 7 (1954). See Western Oklahoma Gas & Fuel Co. v. State, 113 Okl. 126, 239 P. 588 (1925).
>
> "The rule also prevents the company from employing future rates as a means of ensuring the investments of its stockholders. Georgia Ry. & Power Co. v. Railroad Commission of Georgia, 278 F. 242 (D.C. Ga. 1922). If a utility's income were guaranteed, the company would lose all incentive to operate in an efficient, cost-effective manner, thereby leading to higher operating costs and eventual rate increases." Narragansett Elec. Co. v. Burke, 415 A2d 177, 178-79 (RI 1980).

Thus, the rule protects ratepayers by ensuring that they know the maximum cost of service at the time they use the service. The rule also promotes efficiency by the utilities in two ways. First, the utility is encouraged to keep costs down because it cannot recoup its excess past or present costs in the future. Second, if the utility's cost containment measures result in unexpected profits for the utility, those profits are a bonus to the utility that cannot be taken from it.

Origins of the Rule Against Retroactive Ratemaking

Courts and commissions have long recognized the rule against retroactive ratemaking. Cases applying the rule often refer to it as a well-settled principle, but those decisions do not discuss the origins or legal bases of the rule. See, e.g., T.W.A. v. Civil Aeronautics Board, 336 US 601, 605, 69 S Ct 756, 93 L Ed 911 (1949) ("customary pattern of fixing rates prospectively"); Pennsylvania Pub. Util. Comm'n. v. Philadelphia Elec. Co., 56 PUR 4th 637, 672 (1983), aff'd in part 93 Pa Commw 410, 502 A2d 722 (1985) ("It is axiomatic that ratemaking is prospective in nature").

The principle that a utility is entitled to an opportunity to earn a reasonable rate of return underlies any discussion of ratemaking. See Southern Cal. Edison Co. v. Public Util. Comm'n., 20 Cal3d 813, 144 Cal Rptr 905, 576 P2d 945, 949 n 8 (1978) (hereafter Edison). Rates that are set too low to allow a utility an opportunity to earn a reasonable rate of return are confiscatory. The setting of such rates violates the Fifth and Fourteenth Amendments to the United States Constitution by depriving a utility of property without just compensation. NY Tel., supra, 271 US at 31. A utility, however, must bear the risk that it will be unable to achieve its authorized, reasonable rate of return. Id.

a. Use of Past Losses in Rate-Setting

The earliest United States Supreme Court case discussing the use of past losses in setting future rates is Knoxville v. Water Co., 212 US 1, 29 S Ct 148, 53 L Ed 371 (1909). The Court stated that the company's duty is to exact sufficient returns to ensure that investment in the company is kept unimpaired. Id. at 14. The Court held that in a rate case, if unwarranted dividends or other managerial imprudence resulted in past losses, the true value of the company's property cannot be enhanced by a consideration of the past losses. Id. The Court concluded, "The precise subject of inquiry was, what would be the effect of the ordinance in the future." Id. at 15.

The Court in Knoxville reversed the lower court's holding that rates set by the city that did not take into account the company's past losses were confiscatory. Thus, the Court refused to enjoin operation of the city's rate ordinance. The Court, however, stated that the company could later apply to enjoin the statute if it proved to operate as a confiscation of property. Id. at 17-19.

b. Use of Past Profits in Rate-Setting

The United States Supreme Court considered the use of past profits in setting future rates in Newton v. Consolidated Gas Co., 258 US 165, 42 S Ct 264, 66 L Ed 538 (1922). The state had sought to justify the rates it set by statute on the basis of past profits earned by the company. The Court stated:

> "Since 1907 the Gas Company has been subject to supervision by a Commission empowered to prohibit unreasonable rates and the presumption is that any profits from its business were lawfully acquired. Mere past success could not support a demand that it continue to operate indefinitely at a loss. The public has no such right in respect of private property although dedicated to public use. When it became clear that the prescribed rate had yielded no fair return for more than a year and that this condition would almost certainly continue for many months the company was clearly entitled to relief." Id. at 175 (citation omitted).

The Court affirmed that portion of the lower court order holding that the rates were confiscatory.[4] Id. at 177.

Thus, Newton and Knoxville provide the first statements of two well-settled ratemaking principles: (1) Past profits cannot be used to sustain confiscatory rates for the future. Los Angeles Gas Co. v. R.R. Comm'n., 289 US 287, 313, 53 S Ct 637, 77 L Ed 1180 (1933); Newton v. Consolidated Gas Co., supra, 258 US at 177; and (2) A utility cannot rely on past losses to argue that future rates are confiscatory. Galveston Elec. Co. v. Galveston, 258 US 388, 395, 42 S Ct 351, 66 L Ed 678 (1922); Knoxville v. Water Co., supra, 212 US at 14. These two principles combined form the rule against retroactive ratemaking. See Consumers Council, 585 SW2d at 59, discussed supra at 1.

The rule against retroactive ratemaking prohibits incorporation of past profits or losses in future rates. The bar against incorporation of past profits derives from the constitutional prohibition on setting confiscatory rates; use of past profits in setting future rates may produce confiscatory rates. In contrast, the prohibition against incorporation of past losses is not a constitutional rule, although the concept of confiscation plays a role in its operation. A utility is entitled to relief if its rates are confiscatory. If a utility tries to argue that future rates are confiscatory when past losses are not incorporated into the future rates, Galveston and Knoxville require rejection of the utility's argument. The utility cannot erect a constitutional violation out of rates which, viewed prospectively, are compensatory.

All public utility regulators are empowered to set just and reasonable rates. In most jurisdictions, the enabling statute explicitly grants the regulator such authority. See Pacific Tel. & Tel. Co. v. Public Util. Com., 62 Cal2d 634, 44 Cal Rptr 1, 401 P2d 353, 363 (1965). Most jurisdictions also explicitly state that the rates are to be observed in the future. Id. The Oregon Public Utility Commissioner is empowered to protect utility customers and the public "from unjust and unreasonable exactions and practices and to obtain for them adequate service at fair and reasonable rates." ORS 756.040(1). No regulator has ever been authorized to set rates that are not just and reasonable.

These principles, and thus the rule against retroactive ratemaking, operate in the following manner. Suppose a utility had profits of $5,000,000 in excess of the rate of return established in the last rate case. The regulator then determines the utility's revenue requirement for the next year to be $100,000,000 and establishes a rate of return to produce that revenue. Just and reasonable rates would be designed to yield

$100,000,000 in revenue. If the regulator considers the previous year's $5,000,000 excess profits and sets rates to produce only $95,000,000 in revenue, then the rates are less than just and reasonable and are confiscatory because, viewed prospectively, they do not allow the utility to earn a reasonable rate of return. Thus, the regulator has violated its statutory duty to set just and reasonable rates, and the rates violate the utility's constitutional right to an opportunity to earn a reasonable rate of return. In effect, the regulator has taken the utility's property from the utility without just compensation. The property that is taken is the utility's future earnings. The amount of future earnings taken in this case is equal to the utility's past profits.

Similarly, past losses cannot be used in setting future rates. Suppose a utility earned $5,000,000 less than authorized last year, and has a revenue requirement of $100,000,000 for next year. If the ratesetting body considers the $5,000,000 shortfall and sets rates designed to produce $105,000,000 in revenue, then the rates will exceed just and reasonable rates.[5] Rates set to make up for a previous shortfall have the effect of shifting to the ratepayer the utility's risk that it will not earn its authorized rate of return.

One court has suggested that this shift of risk may violate the ratepayers' constitutional rights by depriving them of property without due process of law in the same way that a utility would be deprived of property without due process if it were required to apply past profits to future rates in order to earn a reasonable rate of return: The ratepayer has paid for and received service. Then, after the transaction is done, the ratepayer must pay more without receiving any more service. See In re Cent. Vermont Public Service Corp., supra, 473 A2d at 1158. Moreover, the change in past obligations may violate the impairment of contracts clause of Article I, section 10 of the United States Constitution.[6]

The nature of the ratemaking process further supports the rule against retroactive ratemaking. Ratemaking is purely legislative in character, derives its authority from the legislature and is regarded as an exercise of the legislative power.[7] Rates established by regulators enjoy a presumption of validity and, therefore, have the force and effect of statutes. Arizona Grocery, supra, 284 US at 386 and n 15; New Eng. T. & T. Co. v. Public Utilities Commission, supra, 358 A2d at 20. See ORS 756.561. Legislative acts are prospective; retroactivity, even where permissible, is not favored except upon the clearest mandate. Claridge Apartments Co. v. Comm'r, 323 US 141, 164, 65 S Ct 172, 89 L Ed 139 (1944).

Thus, the rule against retroactive ratemaking is a combination of several other rules and legal principles. First, the rule against retroactive ratemaking, insofar as it prohibits incorporation of past profits in future rates, derives from and is rooted in the constitutional prohibition against setting confiscatory rates. The rule against retroactive ratemaking, insofar as it prohibits incorporation of past losses in future rates, has no constitutional basis. One might argue that this part of the rule derives from notions of fairness; if past profits cannot be used to make future rates lower, past losses should not be used to make future rates higher. The United States Supreme Court, however, in the earliest pronouncements on this part of the rule, did not consider these notions of fairness, but ruled that the proper inquiry was the effect of the rates in the future. Knoxville v. Water Co., supra, 212 US at 15.

Second, ratepayers' constitutional rights may be violated if ratepayers are required to pay in the future a surcharge for services they used under lawful rates. See In re Cent. Vermont Public Service Corp., supra, 473 A2d at 1158. Such a surcharge may deprive ratepayers of property without due process or violate the contracts clause of the United States or Oregon Constitution.

Third, as suggested by Knoxville, the rule against retroactive ratemaking is derived from and rooted in the legislative nature of the ratemaking process. A legislature, however, can explicitly authorize a regulator to set rates retroactively. For example, a legislature may permit rates to be set retroactively to the date that the utility applied for the new rates. See, e.g., T.W.A. v. Civil Aeronautics Board, supra, 336 US at 605. Legislative authorizations of retroactive ratemaking are subject to constitutional limitations. American Can v. Lobdell, 55 Or App 451, 461, 638 P2d 1152, rev den 293 Or 190 (1982). Thus, a legislature could not authorize a regulator to use past profits in setting future rates.

The fourth component of the rule against retroactive ratemaking is the regulator's statutory duty to set just and reasonable rates. Incorporation of past profits in future rates may result in rates that, when viewed prospectively, are confiscatory. Similarly, incorporation of past losses in future rates may result in rates that exceed just and reasonable rates.

To the extent that components of the rule against retroactive ratemaking are constitutional in genesis, they are inviolable. Because some components of the rule are not constitutional rules, those components may be changed by legislation so long as the legislation does not violate the United States or Oregon Constitution.

PART II

Application of the Rule to Oregon

Although Oregon courts have never ruled on the issue of retroactive ratemaking, we have no question that retroactive ratemaking is unlawful in Oregon. First, as already noted, to the extent that the rule has its genesis in the United States Constitution (or in parallel Oregon constitutional provisions), the rule necessarily applies in Oregon. Second, the aspect of the rule that derives from the generally prospective nature of substantive laws finds support in Oregon. See American Can v. Lobdell, supra, 55 Or App at 461 (ratemaking is a legislative function); Joseph v. Lowery, 261 Or 545, 495 P2d 273 (1972) (substantive legislation applied prospectively). Third, in Oregon as elsewhere a public utility's rates must be "reasonable and just," a requirement violated by retroactive ratemaking. And fourth, we strongly believe that Oregon courts would follow the unanimous and well-reasoned authorities in other jurisdictions that have held that retroactive ratemaking is invalid.

Having so concluded, we turn to your specific questions. With respect to each proposed order, we first must determine whether the commissioner has statutory authority to issue the order. Second, we must determine whether the order is retroactive and, if so, whether the order involves ratemaking. If the first two determinations support issuance of the order, we must then determine whether the rule against retroactive ratemaking and state or federal constitutional guarantees have not been violated.

1(a): Deferral of Revenue Collection

You ask whether you may issue an order establishing the expected level of operating costs and the return on the added rate base of a new electric generation plant, but deferring the collection of revenues to cover the operating costs and return on rate base until a specific later period. We conclude that the commissioner has no statutory authority to issue such an order.

The commissioner is authorized to exercise jurisdiction over utilities "to protect [their] customers, and the public generally, from unjust and unreasonable exactions and practices and to obtain for them adequate service at fair and reasonable rates." ORS 756.040(1). The commissioner has power "to do all things necessary and convenient in the exercise of such power and jurisdiction" over the utilities. ORS 756.040(2).

Thus, the Public Utility Commissioner has been granted the broadest authority, commensurate with that of the legislature itself, for the exercise of the commissioner's regulatory function. American Can Co. v. Davis, 28 Or App 207, 216, 559 P2d 898, rev den (1977). That authority, however, is not without limits. For example, the Oregon Court of Appeals invalidated the commissioner's "tagline rule," whereby all investor-owned utilities were required to include in all advertisements a line that the advertisement was paid for by customers or stockholders of the utility, because the rule was not within the limits of the commissioner's delegated authority. Pacific Northwest Bell v. Davis, 43 Or App 999, 1006, 608 P2d 547 (1979), rev den 289 Or 107 (1980).

The legislature has specifically set forth the commissioner's ratemaking authority in ORS chapter 757. ORS 757.210(1) permits the commissioner to hold a hearing upon any rate filing by a utility. That statute requires the commissioner to conduct hearings on rates upon a written complaint filed by the utility, its customers or other proper party within 60 days of the filing of new rates by a utility. No hearing is required if the rate change is the result of an automatic adjustment clause.

The commissioner may suspend the new rates pending investigation of them. ORS 757.210(1). If the commissioner holds a hearing on the proposed rates and does not order a suspension of the rates, any increased revenue received by the utility is subject to refund if the commissioner approves rates that are less than the proposed rates. ORS 757.215(4).

Because the legislature has granted specific ratemaking authority to the commissioner, the legislature impliedly has limited the commissioner's ratemaking authority to that which the legislature has specifically granted. The commissioner also has such implied powers as are necessary to carry out the powers expressly granted. See Warren v. Marion County, 222 Or 307, 319-20, 353 P2d 257 (1960). Thus, the commissioner's ratemaking authority is limited to the powers bestowed on the commissioner by the legislature and those implied powers necessary to carry out the explicitly granted powers. See, e.g., Niagara Mohawk Power v. Pub. Serv. Comm'n, 118 AD2d 908, 499 NYS2d 477 (1986) (no statutory authority to refund overcollections pursuant to fuel adjustment clause). Because ratemaking is a legislative function and substantive legislation is applied prospectively absent explicit direction to the contrary, a ratemaking order that has retroactive effect is lawful only if specifically authorized by the legislature and cannot be supported only by the commissioner's general powers.

The commissioner has no explicit authority to issue a deferred accounting order. The commissioner, therefore, only has power to issue a deferred accounting order if the order is necessary to carry out the commissioner's ratemaking powers.

We conclude that the commissioner's general power "to do all things necessary and convenient" to protect the public from "unjust and unreasonable exactions and practices," ORS 756.040(1) and (2), does not authorize the commissioner to issue a deferred accounting order. Deferred collection would not protect ratepayers in the required manner. On the contrary, deferred collections harm ratepayers because deferred collections mask the true cost of service and result in ratepayers at one time paying for service that was provided to other customers in the past. A deferred collection order, therefore, would violate the rule against retroactive ratemaking.

Two cases from other jurisdictions expose the retroactive ratemaking nature of deferred accounting orders. In Chesapeake & Potomac Tel. Co. v. Public Serv. Com'n, 330 A2d 236 (DC 1974) (hereafter Chesapeake), the commission granted Chesapeake interim rate relief when it filed for a rate increase, but deferred actual collection under the interim rates until after the establishment of permanent rate schedules to which the interim increase would be added as a surcharge. The company objected. It argued that the plan violated the rule against retroactive ratemaking because it created higher future rates to recoup past losses. Id. at 238, 240.

The court of appeals held that the rule against retroactive ratemaking was not violated because the relief granted by the commission was prospective only.[8] Id. at 241. The court, however, acknowledged that the consumers who used the service during the interim period would be different from those who would pay for the service after the new rates went into effect. Id. at 242-43. This argument did not persuade the court that its order had retroactive effect. Instead, the court found that the two groups of consumers were substantially the same. Id. at 243.

A Pennsylvania court considered a deferred accounting issue in Philadelphia Elec. Co. v. Pa. Pub. Util. Com'n, 93 Pa Commw 410, 502 A2d 722 (1985) (hereafter PECO). In that case, the utility had voluntarily deferred depreciation and maintenance expenses and sought to have those expenses applied to future rates. Id. at 724. The court affirmed the commission's refusal to apply the deferred accounts to future rates because the expenses were usual and expected expenses that the utility could have recovered in an earlier rate proceeding. Id. at 728.

A comparison of Chesapeake and PECO shows that Chesapeake was wrongly decided. In PECO, the commission and court did not order the utility to defer past expenses. In Chesapeake, the commission and court, over the utility's objection, ordered the utility to defer revenue. The commission's statement, and the Chesapeake court's reliance on the statement, that the order had prospective effect, underscores the commission's and the court's misunderstanding of the rule against retroactive ratemaking. The order operated prospectively only insofar as the deferral took place after the order and collection of the deferred revenues took place after that. "Prospective" used in that sense, however, is not "prospective" in the sense permitted by the rule against retroactive ratemaking.

The rule prohibits a rate order for the future that allows recovery of past losses or imposes an additional charge arising from past use of utility service. See supra at 1-2. In both Chesapeake and PECO, the deferrals would operate prospectively in that the recovery for expenses or the revenue would have occurred after issuance of the order. In PECO, however, the utility's proposal would have allowed the utility to recover in the future for its past expenses. That is a patent violation of the rule against retroactive ratemaking. Similarly, in Chesapeake, the commission's order deferring revenues meant that Chesapeake had to operate under its old rates despite the interim order allowing, but deferring, a rate increase. Thus, Chesapeake incurred losses because it was forced to operate under its old rates despite the commission's finding that Chesapeake was entitled to increased rates.

After the new rates were finally set and collection of the deferred interim increase allowed, the result was that the company was allowed to recover under new rates for losses incurred under old rates. That is the essence of retroactive ratemaking, that is, an attempt to produce a sum from future rates which would have been produced had rates been higher in the past. The company was allowed to charge rates exceeding just and reasonable rates (the new just and reasonable rates plus the surcharge for the interim increase).

The deferred interim rate relief in Chesapeake offends the underlying rationale of the rule. Customers who used service during the deferral period were unaware of the actual cost of service. Even if they knew the actual cost, the deferral offended the policy that service should be paid for when it is used. Customers would have to pay for past service when the new rates went into effect. Furthermore, new customers at the time the new rates went into effect would be paying for past use of service by other customers.[9] Moreover, a deferred revenue order offends the policy embodied in ORS 757.310(1)(a) that a utility may charge no more or no less for service than that stated in public rate schedules at the time the service is rendered.

Thus, analysis of Chesapeake and PECO demonstrates that deferred accounting, that is, deferral of a utility's current expenses to be applied to future rates, violates the rule against retroactive ratemaking. The rule is violated whether the utility voluntarily defers accounting with the hope or expectation that the regulator will allow future recovery or the regulator orders the utility to use deferred accounting.

Under the deferred collection order that you propose, like the proposed order in PECO and the order in Chesapeake, the deferral and subsequent collection would occur after the order is issued. That timing, however, does not mean that the deferred collection order satisfies the rule against retroactive rate-making. If ratepayers at a given time are required to pay costs of service at a previous time, the rule against retroactive rate-making is violated even if the order authorizing the deferral is antecedent to the time during which revenue is deferred.

For example, if the commissioner issued an order in 1987 setting rates for Utility Company for 1990 with the provision that in 1991 ratepayers would be subject to a surcharge if Utility did not achieve its authorized rate of return in 1990, such an order would violate the rule against retroactive rate-making because customers in 1991 would be required to pay for past losses, even though the utility's shortfall and the surcharge against ratepayers both occur after the order is issued. Such an order is precisely the type of deferred collection order you propose and the type approved by the court in Chesapeake. Such an order would offend the policy of the rule against retroactive ratemaking that a customer should know and pay the cost of service when the ratepayer uses the service. In the absence of a threat to the financial integrity of the Company, such a surcharge also might unconstitutionally impair the obligation of contracts and violate the ratepayers' right not to be deprived of property without just compensation.

Similarly, if the commissioner issued an order in 1987 setting rates for 1990 with the provision that in 1991 ratepayers would be entitled to a refund if the utility exceeded its authorized rate of return in 1990, such an order would violate the rule against retroactive ratemaking because the company would be required to refund its past profits. Such a requirement would be a confiscation in violation of the Fourteenth Amendment to the United States Constitution. Moreover, such an order would be economically inefficient and contrary to the policy of the rule; the company would lose any incentive to economize during 1990.

A rate order establishing a mechanism that, like a deferred accounting order, balances past costs and future rates, might satisfy the cited constitutional provisions if (1) the commissioner were authorized to establish such a balancing mechanism; (2) the balancing mechanism is a part of the tariff; and (3) the balancing mechanism applies to rates in effect after the balancing mechanism is established. Despite the potential lawfulness of such a balancing mechanism, the mechanism could violate the spirit of the rule against retroactive ratemaking. On one hand, the policy behind the rule that a customer should know and pay the cost of service when the customer uses the service would not be served by inclusion of a balancing mechanism in the tariff. Although the customer would know that the service was subject to refund or surcharge, the customer would never know the actual cost of service until after the service is used. On the other hand, utilities would lose their incentive to operate efficiently and to reduce costs if they knew that they could easily surcharge their customers to cover any shortfalls.[10]

In Order No. 86-1078, issued October 23, 1986, the commissioner allowed Pacific Power & Light (PP&L) to defer billing and revenue collection with respect to its investment in the Jim Bridger Unit 2 flue gas desulfurization system, with the proviso that all deferred accruals were subject to the commissioner's final approval before being included in rates. This situation is similar to that in PECO, supra: PP&L voluntarily deferred revenue when it could have sought and obtained an interim order including the expense in its current rates. The only difference in PP&L's case is that the commissioner issued an order approving the deferral. PP&L is entitled to defer revenues, but it is not entitled to recoup the deferred revenue. The commissioner may, however, allow the utility to recoup the deferred revenue if, and only if, the regulator has authority to do so. Under Oregon law, the commissioner has no authority to allow PP&L to recoup its deferred revenue.

The United States Supreme Court has said that if a utility agrees by contract to a rate that affords it less than a reasonable rate of return, the utility is not entitled to be relieved of its improvident bargain. F.P.C. v. Sierra Pacific Power Co., 350 US 348, 355, 76 S Ct 368, 100 L Ed 388 (1956). A utility, however, may be relieved of its bargain if the utility is on the verge of financial collapse. Id. Thus, as in PECO, a utility may agree to defer revenues, but it is not entitled to recoup the deferred revenue in a ratemaking proceeding.

Order No. 86-1078 was part of docket UE 52. Order No. 86-605, issued June 20, 1986, also was part of docket UE 52. In Order No. 86-605, the commissioner approved PP&L's motion for an interim rate increase. The commissioner also approved PP&L's request that its share of Colstrip Unit 4 be placed in rate base effective June 23, 1986, and that it defer the revenue on Colstrip Unit 4 from June 23, 1986, forward. Collection of the deferred revenue accruals pursuant to both orders was made subject to the commissioner's approval of inclusion of the accruals in PP&L's rates.

The deferrals pursuant to both orders continued until issuance of the final order in UE 52 in January 1987. The deferral of revenues approved in Order No. 86-605 violated the rule against retroactive ratemaking for the same reasons that Order No. 86-1078 violated the rule: Upon collection of the deferred revenues, customers would be required to pay an additional charge for past use of utility service. New customers who were not customers during the deferral period would be required to pay for past service rendered by PP&L.

The deferral of revenues meant that PP&L had to continue to operate under old rates despite the commissioner's recognition that PP&L was entitled to a revenue increase. Thus, PP&L incurred losses during the period of the deferral. Upon collection of the deferred revenue, ratepayers would pay for that past loss. This was the situation in Chesapeake, supra. UE 52, however, differed from Chesapeake in one respect: In UE 52, PP&L requested the deferral.

The commissioner lacked authority to issue the deferred collection order. Thus, if the commissioner were to disallow collection of the deferred revenue in the final order in UE 52, PP&L could not argue successfully that the commissioner was estopped from issuing the denial by his approval of the interim orders deferring the revenue. The commissioner cannot be estopped from overturning a previous order he had no authority to issue.

1(b): Use of Balancing Account to Recover Additional Power Costs

You ask whether you may issue an order establishing a balancing account for fuel costs. The order you propose would state: power costs incurred as a part of normal operations cannot be accurately predicted; the utility should account for such costs in a balancing account; and the utility should increase rates to recover those accumulated costs in a specific later period. We conclude that the commissioner may employ an automatic adjustment clause to adjust rates prospectively to reflect future costs more accurately, but that the commissioner lacks authority to allow the utility retroactively to recover past fuel costs.

There are two types of fuel adjustment clauses. A "cost of service" tariff is a fuel adjustment clause that is designed to recover all past costs on a dollar-for-dollar basis. It is, in essence, a deferred billing system. Under a cost of service tariff actual fuel costs for a given month are recovered through a surcharge in a later month. A typical cost of service tariff permits a utility to recover costs incurred two months earlier by allowing the utility to adjust its bills to customers to recover fuel costs incurred two months before the billing month. The regulator must have statutory authority to include a fuel adjustment clause in a tariff. See Detroit Edison Co. v. Mich. Pub. Serv. Com'n, 416 Mich 510, 331 NW2d 159, 161-62 (1982). Compare Colo. Energy Advocacy v. Pub. Serv. Co. of Colo., 704 P2d 298 (Colo 1985) (upholding cost of service tariff) with In re Cent. Vermont Public Service Corp., supra, 473 A2d at 1155 (no statutory authority to enact cost of service tariff).

A "fixed rate" tariff, on the other hand, is a fuel adjustment clause that uses costs incurred in a past month to estimate current expenses. Each month acts as a test period for setting fuel costs for the following month. Under a fixed rate tariff, deferred billing is not permitted because the fixed rate tariff is intended to estimate cost and not to provide recovery of actual costs. Thus, surcharges are not authorized under a fixed rate fuel adjustment clause. See Detroit Edison Co. v. Mich. Pub. Serv. Com'n, supra, 331 NW2d at 162. See also Virginia Elec. & Power Co. v. FERC, 580 F2d 710 (4th Cir 1978) (fixed rate tariff, surcharge disallowed); Maine Public Serv. Co. v. Federal Power Com'n, 579 F2d 659 (1st Cir 1978) (remanded to determine whether surcharge was pursuant to an acceptable adaptation of earlier cost of service fuel adjustment clause or forbidden retroactive ratemaking).

Both cost of service and fixed rate tariffs allow a utility to adjust its rates with respect to fuel costs without the necessity of a full blown rate case. In most jurisidictions, including Oregon, the utility must apply to the regulatory body for approval of the adjustment mechanism, but no hearing is necessary for each adjustment once the clause has been approved for use. See id. at 663; Edison, supra, 576 P2d at 947; ORS 757.210.

Fixed rate fuel adjustment clauses do not violate the rule against retroactive ratemaking because they operate prospectively in the same way that general ratemaking proceedings operate prospectively; a test period is used to predict future rates that operate in futuro.

ORS 757.210(1) states, in pertinent part:

> "The term 'automatic adjustment clause' means a provision of a rate schedule which provides for rate increases or decreases or both, without prior hearing, reflecting increases or decreases or both in costs incurred by a utility and which is subject to review by the commissioner at least once every two years."

No hearing is necessary for rate changes that are the result of automatic adjustment clauses. ORS 757.210(1).

ORS 757.210(1) authorizes the commissioner to include automatic adjustment clauses in utility tariffs. The automatic adjustment clauses authorized by ORS 757.210(1), unlike the adjustment clauses in most other jurisdictions, apply to all utility costs and not fuel costs only. ORS 757.210(1) does not specify whether it authorizes fixed rate or cost of service adjustment clauses.

The general rule is that ratemaking is prospective unless the legislature expressly authorizes retroactive ratemaking. See Joseph v. Lowery, supra, 261 Or at 545 (substantive legislation operates prospectively absent express direction to the contrary); American Can v. Lobdell, supra, 55 Or App at 461 (ratemaking is legislative function). Thus, the legislature's grant of authority to the commissioner to include automatic adjustment clauses in utility tariffs does not authorize cost of service adjustment clauses because cost of service clauses have retroactive effect. The commissioner, therefore, is authorized by ORS 757.210(1) to include fixed rate fuel adjustment clauses in utility tariffs.

If the commissioner were authorized to include cost of service adjustment clauses in utility tariffs, the rule against retroactive ratemaking would be implicated. A cost of service tariff, however, while retroactive in operation, does not violate the rule for at least three reasons.

First, the regulator must be authorized to include a cost of service adjustment clause in the tariff. By that authorization, the legislature explicitly declares its intention that retroactive treatment is permitted for the limited purpose of allowing a utility to recover actual fuel costs and to refund overcollections of anticipated fuel costs. Second, the constitutional prohibition against setting confiscatory rates is not implicated by a cost of service fuel adjustment clause. Even where the utility is required to refund overcollections of fuel costs, there is no impact on the utility's authorized rate of return and the utility still recovers its actual fuel costs. Third, past losses or excess profits are not used in setting future rates under a fuel adjustment clause. The clause does not guarantee the utility a rate of return, nor does it require the utility to refund excess profits to the ratepayers. On the contrary, a cost of service fuel adjustment clause is a true-up mechanism that assures that a utility will recover no more or less than its actual fuel costs.

The constitutional prohibition against setting confiscatory rates is not violated by a cost of service adjustment clause because the rates authorized originally, and which met the constitutional standard, contemplated that the utility would recover only its actual fuel costs. All else being equal, theoretically if a utility recovered more than its fuel costs, it would be overearning, and if it recovered less, it would be underearning. Therefore, a mechanism which in effect can completely remove one element of cost cannot affect the constitutionality of rates otherwise set at a constitutional level.

If the legislature authorizes the commissioner to include cost of service fuel adjustment clauses in utility tariffs, establishment of a balancing account may be appropriate. A balancing account may be used in conjunction with a cost of service fuel adjustment clause. See Utah Dept. of Bus. Reg. v. Public Service Com'n, 720 P2d 420 (Utah 1986). If there is an overcollection in one month, the money can be placed in the balancing account rather than refunded to customers. Rates are then adjusted downward so that there is no overcollection in the subsequent month and so that money in the balancing account is applied toward costs. If the adjustment causes the balancing account to dip below zero, rates in the next month would be raised to reflect higher costs and to enable the utility to recover its expenses. Thus, a balancing account in conjunction with a cost of service adjustment clause replaces refunds and surcharges as the true-up mechanism.

Hence, we conclude that the commissioner may not authorize a utility to set up a balancing account for anticipated power costs. The commissioner may, however, include an automatic adjustment clause in the utility's tariff, and that clause must be subject to review by the commissioner at least once every two years. See ORS 757.210(1). The automatic adjustment clause must be of the "fixed rate" type.

1(c): Use of Balancing Account to Review Costs Under Cogeneration Contracts

Next, you ask whether you may issue an order establishing a balancing account for costs incurred under a series of cogeneration contracts. This question and the order you propose are precisely like the previous one, except that the previous question involved power costs incurred as a part of normal operations and this involves power costs incurred pursuant to cogeneration contracts. We conclude that you may authorize use of an automatic adjustment clause to apply to power costs under cogeneration contracts to the same extent as to fuel costs from normal operations.

The definition of "automatic adjustment clause" refers to increases or decreases in costs without differentiating between the sources of costs. ORS 757.210(1).[11] Costs pursuant to cogeneration contracts, therefore, may be the subject of an automatic adjustment clause in the same way as any other volatile cost. The automatic adjustment clause must be of the fixed rate type and must be included in the utility's tariff and be subject to the commissioner's review at least once every two years. See ORS 757.210(1). The balancing account you propose, therefore, could not be used for the reasons previously stated, supra at 14-17.

2. Revenue Adjustment Clause

You ask whether there is any legal basis for you to issue an order that would (1) forecast expected net revenues from a customer class; (2) set rates based on that net revenue level; (3) require the utility to account for any differences between expected and actual net revenues in a balancing account; and (4) require the utility to adjust rates and surcharge or refund accumulated differences in a specific later period. We conclude that such an order is not authorized by statute and that it would violate the rule against retroactive ratemaking.

This question posits an order that in all respects is similar to the orders in questions 1(b) and 1(c) except that the proposed order here seeks to adjust for revenues rather than for costs. The only adjustment clauses authorized in the commissioner's enabling legislation are those that adjust for costs incurred by utilities. No statute authorizes or even remotely contemplates a "revenue adjustment clause." The commissioner, therefore, has no authority to issue an order containing a "revenue adjustment clause."

In addition, a "revenue adjustment clause" would violate the rule against retroactive ratemaking. Revenue adjustments are the precise evil against which the rule against retroactive ratemaking protects. Under that rule, if actual revenues fall short of predictions, the utility must bear that loss. If actual revenues exceed predictions, the utility is permitted to retain that excess profit. Thus, the utility is encouraged to operate efficiently.

The commissioner must protect the public from "unjust and unreasonable exactions and practices" and obtain for the public "adequate service at fair and reasonable rates." ORS 756.040(1). A "revenue adjustment clause" would be an unjust and unreasonable practice for at least two reasons. First, if all other elements of the revenue requirement remain unchanged, a revenue adjustment clause would ensure that a utility would earn its rate of return. Utilities would have no incentive to operate efficiently because their rate of return would be insured by an eventual surcharge against ratepayers. The cost to consumers, therefore, would rise. Regulators must allow regulated utilities an opportunity to earn a reasonable rate of return. Regulators cannot ensure that utilities will earn a reasonable rate of return.

Second, even if the revenue adjustment clause did not ensure that the utility would earn its authorized rate of return, as may be the case where only one revenue class is subject to the revenue adjustment clause, a revenue adjustment would result in ratepayers paying an additional charge for past service if the forecasted revenues were not achieved. If, on the other hand, forecasted revenues were exceeded, the utility would be required to refund past profits to ratepayers without just compensation to the utility. Thus, the proposed revenue adjustment clause violates the rule against retroactive ratemaking whether forecasted revenues are exceeded or not achieved.

Very truly yours,

Dave Frohnmayer

DAVE FROHNMAYER
Attorney General

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[1] "Excessive profits" and "past losses" have unique meanings in the ratemaking context. A utility is said to have "excess profits" when it earns a rate of return greater than that authorized by the regulator. Similarly, past losses occur when a utility has failed to earn its authorized rate of return even if the utility does not actually lose money. See, e.g., Utah Dept. of Bus. Reg. v. Public Service Com'n, supra, 720 P2d at 422 (company earned 13.25 percent compared to authorized 16.3 percent rate of return).

[2] A "test year" is a year of actual experience that is adjusted to remove abnormalities. The regulator determines expected operating expenses and rate base for the rate period based upon the test year.

[3] See F.P.C. v. Tennessee Gas Co., 371 US 145, 153, 83 S Ct 211, 9 L Ed2d 199 (1962); Arizona Grocery v. Atchison Ry., 284 US 370, 52 S Ct 183, 76 L Ed 348 (1932) (hereafter Arizona Grocery); City of Los Angeles v. Public Utilities Com'n, 7 Cal 3d 331, 356-57, 102 Cal Rptr 313, 332, 497 P2d 785, 803-04 (1972); People's Natural Gas v. Public Util. Com'n, 197 Colo 152, 590 P2d 960 (1979); Westwood Lake, Inc. v. Dade County, 264 So2d 7, 12 (Fla 1972); Georgia Public Service Com'n v. Atlanta Gas Light Co., 205 Ga 863, 883-84, 55 SE2d 618, 631 (1949); Metropolitan Dist. Com'n v. Department of Pub. Util., 352 Mass 18, 16, 224 NE2d 502, 508 (1967); Detroit Edison Co. v. Mich. Pub. Serv. Com'n, 82 Mich App 59, 67, 266 NW2d 665, 669-70 (1978); Mississippi Public Serv. Com'n v. Home Telephone Co., 236 Miss 444, 455, 110 So2d 618, 624 (1959); Consumers Council, supra, 585 SW2d at 58-59; Montana Horse Products Co. v. Great Northern Ry. Co., 91 Mont 194, 202, 7 P2d 919, 925 (1932); Southwest Gas Corporation v. Public Serv. Com'n, 86 Nev 662, 669, 474 P2d 379, 383 (1970); Appeal of Granite State Elec., 120 NH 536, 538, 421 A2d 121, 122 (1980); New Jersey Power & Light Co. v. State Dept. of P.U., 15 NJ 82, 94, 104 A2d 1, 7 (1954); Matter of Yonkers Elec. Light & P. Co. v. Maltbie, 245 AD 419, 423, 283 NYS 839, 844 (1935); State ex rel Utilities Com'n v. Edmisten, 291 NC 575, 232 SE2d 177, 194-95 (1977); Pike County Light & Power Co. v. Pennsylvania Pub. Util. Comm'n., 87 Pa Commw 451, 487 A2d 118 (1985); Narragansett Elec. Co. v. Burke, 415 A2d 177, 179 (RI 1980); Producers' Refining Co. v. Missouri, K. & T. Ry. Co., 13 SW2d 680, 681 (Tex 1929); City of Norfolk v. Virginia Elec. & Power Co., 197 Va 505, 511, 90 SE2d 140, 145 (1955); In re Cent. Vermont Public Service Corp., 144 Vt 46, 473 A2d 1155, 1159 (1984); Chesapeake v. Public Service Com'n, 300 SE 2d 607, 619 (W Va 1982); Friends of the Earth v. Public Service Com'n, 78 Wis 2d 388, 254 NW2d 299, 309 (1977).

4 The Supreme Court reversed that portion of the lower court order subjecting the company to some unknown rate to be proclaimed in the future. The Court said that "[r]ate making is no function of the courts." Newton v. Consolidated Gas Co., supra, 258 US at 177.

5 The language "just and reasonable" implies that there is a range of rates that the regulator may approve. It could be argued that rates that take into account past losses may still be within the bounds of reasonableness. While this may be true in the case of very small past shortfalls, it is not likely to be true where, as in the example above at 6, the difference in the revenue requirement is 5 percent. The precise point at which rates go beyond the bounds of reasonableness may differ from court to court. Moreover, upon judicial review, if the calculation of the revenue requirement appears to contain an element of past loss, a court likely will reverse and remand even if a regulator could lawfully find that the revenue requirement falls within the bounds of reasonableness.

6 If a utility's past losses are so great that the utility's financial integrity and, hence, its ability to provide service is jeopardized, a retroactive ratemaking order may be permissible. See Hearde v. City of Seattle, 26 Wash App 219, 611 P2d 1375 (1980).

7 Knoxville v. Water Co., supra, 212 US at 8. See Arizona Grocery, supra, 284 US at 389; Pacific Tel. & Tel. Co. v. Public Util. Com., supra, 401 P2d at 363; People's Natural Gas v. Public Util. Com'n, 197 Colo 152, 590 P2d 960 (1979); Michigan Bell Tel. Co. v. Michigan Pub. Serv. Com'n, 315 Mich 533, 24 NW2d 200, 205 (1946); Lambertville Water Co. v. N.J. Bd. of P.U.C., 79 NJ 449, 401 A2d 211 (1979); New Eng. T. & T. Co. v. Public Utilities Commission, 116 RI 356, 358 A2d 1, 20 (1976).

8 Chesepeake is the only case in this country ever to uphold a deferred accounting order in the absence of a fuel adjustment clause. Fuel adjustment clauses are discussed infra at 15.

9 The Chesapeake court pointed to no statutes authorizing the deferred accounting treatment ordered by the commission and approved by the court.

10 The balancing mechanism need not be an automatic adjustment clause. For the mechanism to avoid constitutional violations, the customer must have notice of the balancing mechanism.

[11] Although the statute itself does not differentiate between the sources of cost, the legislative history indicates that fluctuations in natural gas wholesale prices and power costs were the only examples given to the legislative committees to illustrate the function of the automatic adjustment clause. House Committee on Environment and Energy (SB 259), July 7, 1981, tape H-81-EE-255, side B; House Committee on Environment and Energy (SB 259), July 10, 1981, tape H-81-EE-264, side B.

ENERGY UTILITY DEFERRED ACCOUNTS

Covered by Attorney General's Opinion of March 18, 1987

Summary List as of December 31, 1986

Description	$ Balance Incr. or (Decr.)	% of 1986 Oregon Revenues	Reason for Deferral*
PORTLAND GENERAL ELECTRIC			
RPA Balancing Account (A)	$ 18,758,783	2.836%	3
IBP Deferral	660,000	.100	5
PCA Balancing Account	(3,563,000)	(.539)	5
Capital Restructuring Program Deferral	14,258,566	2.155	5
State Tax Normalization Deferral	517,000	.078	5
Pole Inspection Program Deferral	883,761	.134	5
WHIP Admin. Indirect	924,000	.140	5
Weatherization Program - Admin. Costs (B)	22,000	.003	5
Water Heater Wrap - Summer Blitz	81,000	.012	5
WHIP - Direct Incentives	392,000	.059	5
Water Heater Wrap Program	355,000	.054	5
Low Income Weather. Program	140,000	.021	5
Uncollectible Weatherization Write-Off	586,000	.089	5
Unamortized Indirect Costs - Weather. Program (B)	4,944,000	.747	5
Total	$ 38,959,110	5.789%	
CP NATIONAL - ELECTRIC			
RPA Balancing Account (A)	$ (825,464)	(3.213)	3
Inverted Rate Balancing Account	(374,031)	(1.456)	5
CSPP Deferrals	2,480,726	9.655	5
Total	$1,281,231	4.986%	

*Key to Reasons for Deferral.

1. Retroactive changes imposed by a governmental agency.
2. Wholesale price change approved by the Federal Energy Regulatory Commission.
3. Regional Power Act changes.
4. Minimize frequency of rate changes or fluctuations of rate levels.
5. Match costs and benefits or actual costs.

Footnotes:

(A) This account may be exempt from application of the Attorney General's opinion because of the provisions of Section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act of 1980.

(B) Part of the balance in this account may be exempt from application of the Attorney General's opinion because of the specific statutory provision that actual program costs be recovered.

Note: Accounts with credit balances may be exempt from application of the Attorney General's opinion if the utility has a binding commitment to reduce rates to reflect amortization of the balance.

ENERGY UTILITY DEFERRED ACCOUNTS

Covered by Attorney General's Opinion of March 18, 1987

Summary List as of December 31, 1986

Description	$ Balance Incr. or (Decr.)	% of 1986 Oregon Revenues	Reason for Deferral*
PACIFIC POWER & LIGHT COMPANY			
RPA Balancing Account (A)	$ (353,129)	(.067)	3
Recapitalization Program	1,651,993	.314	5
IBP Deferral	(1,025,933)	(.195)	5
Colstrip 4 Deferral	5,876,741	1.115	4
Jim Bridger Pollution Control Deferral	1,788,555	.339	4
Weatherization Loan Program - 0% Interest	3,705,907	.703	5
Residential Water Heater Wrap Program	38,325	.007	5
Hood River Conservation Program	(8,521)	(.002)	5
Total	$11,673,938	2.214%	
IDAHO POWER COMPANY			
CSPP Deferrals	$545,465	3.229%	5
IBP Deferral	42,454	.251	5
Total	$587,919	3.480%	

*Key to Reasons for Deferral.

1. Retroactive changes imposed by a governmental agency.
2. Wholesale price change approved by the Federal Energy Regulatory Commission.
3. Regional Power Act changes.
4. Minimize frequency of rate changes or fluctuations of rate levels.
5. Match costs and benefits or actual costs.

(A) This account may be exempt from application of the Attorney General's opinion because of the provisions of Section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act of 1980.

Note: Accounts with credit balances may be exempt from application of the Attorney General's opinion if the utility has a binding commitment to reduce rates to reflect amortization of the balance.

ENERGY UTILITY DEFERRED ACCOUNTS

Covered by Attorney General's Opinion of March 18, 1987

Summary List as of December 31, 1986

Description	$ Balance Incr. or (Decr.)	% of 1986 Oregon Revenues	Reason for Deferral*
NORTHWEST NATURAL GAS			
ISA Deferral	$5,610,833	2.067%	5
	229,755	.085	5
ISA Amortization	987,069	.364	5
TSSA Balancing Accounts	(554,615)	(.204)	5
	(689,436)	(.254)	5
TSSA Contribution Account	(731,407	(.269)	5
Uncollectible Weatherization Contracts	(8,709)	(.003)	5
Throop Weatherization Survey Costs	220,126	.081	5
Def. Steam Heat Balancing Account	92,535	.034	5
1986 Leakage Reconstruction Program	1,214,903	.448	5
Interim Rate Increase	517,768	.191	4
Transportation Increment	156,044	.057	5
Northwest Pipeline Refund	304,988	.112	2
Northwest Pipeline IS-1 Savings	(172,945)	(.064)	2
Northwest Pipeline D-1 Charge	46,645	.017	2
Northwest Pipeline Demand Chg. Credit	(452,731)	(.167)	2
Def. Cost of Gas Amortization	(65,331)	(.024)	2
Cost of Gas Amort.	(274,755)	(.101)	2
Northwest Pipeline Refund	(69,663)	(.026)	2
Northwest Pipeline Section 104 Refund	(266,359)	(.098)	2
Def. Gas Cost Decrease	(435,431)	(.160)	2
Def. Gas Cost	318,520	.117	2
CIG Refund	(504,608)	(.186)	2
Total	$5,473,196	2.017%	

*Key to Reasons for Deferral.
1. Retroactive changes imposed by a governmental agency.
2. Wholesale price change approved by the Federal Energy Regulatory Commission.
3. Regional Power Act changes.
4. Minimize frequency of rate changes or fluctuations of rate levels.
5. Match costs and benefits or actual costs.

Note: Accounts with credit balances may be exempt from application of the Attorney General's opinion if the utility has a binding commitment to reduce rates to reflect amortization of the balance.

ENERGY UTILITY DEFERRED ACCOUNTS

Covered by Attorney General's Opinion of March 18, 1987

Summary List as of December 31, 1986

Description	$ Balance Incr. or (Decr.)	% of 1986 Oregon Revenues	Reason for Deferral*
CASCADE NATURAL GAS			
Oregon Water Heater Program	68,930	.323	5
Astoria Cleanup Costs	315,000	1.474	5
Oregon 8/1/86 Gas Cost Decrease	(177,630)	(.831)	2
Northwest Pipeline Demand Chg. Credit	(53,683)	(.251)	2
1986 Northwest Pipeline Refunds	(69,313)	(.324)	2
Northwest Pipeline Commodity Cost Decreases	(63,261)	(.296)	2
Oregon Gas Cost Reduction Credit (4/85)	33,436	.156	2
Oregon 5/85 Technical Adj. No. 1	13,181	.062	2
Oregon 5/85 Technical Adj. No. 3	3,454	.016	2
Oregon 5/85 Technical Adj. No. 2	(2,865)	(.013)	2
Oregon 7/1/85 Gas Cost Decrease	(1,319)	(.006)	2
11/1/86 Oregon Demand Cost Increase	14,283	.067	2
Total	$ 80,213	0.377%	
CP NATIONAL - GAS			
ISA Balancing Account	$(28,426)	(.098)	5
Northwest Pipeline Refund	(66,989)	(.231)	2
CIG Surcharge Refund	(51,796)	(.179)	2
I.S. Overcollection	(21,293)	(.073)	2
Incentive Gas Overcollection	(10,078)	(.035)	2
Interim Commodity Cost Balancing Account	(81,197)	(.280)	2
Northwest Pipeline 11/1/86 Decrease	(88,328)	(.305)	2
$150 Water Heater Rebate Deferral	62,376	.215	5
Total	$(285,731)	(0.986)%	

*Key to Reasons for Deferral.

1. Retroactive changes imposed by a governmental agency.
2. Wholesale price change approved by the Federal Energy Regulatory Commission.
3. Regional Power Act changes.
4. Minimize frequency of rate changes or fluctuations of rate levels.
5. Match costs and benefits or actual costs.

Note: Accounts with credit balances may be exempt from application of the Attorney General's opinion if the utility has a binding commitment to reduce rates to reflect amortization of the balance.

ENERGY UTILITY DEFERRED ACCOUNTS

Not Covered by Attorney General's Opinion of March 18, 1987

Summary List as of December 31, 1986

Description	$ Balance Incr. or (Decr.)	% of 1986 Oregon Revenues
Property Sales		
Portland General Electric		
Boardman	$(96,605,174)	(14.604)
Columbia - Willamette	(2,333,750)	(.353)
Statutory Mandate		
Portland General Electric		
Weatherization Rebate Program	226,000	.034
Comm./Ind. Energy Mgt. Program	987,000	.149
Pacific Power & Light		
Weatherization Loans - 6 1/2%	458,857	.087
Commercial Conservation Program	340,115	.065
Nuclear Waste Disposal Costs	228,408	.043
Idaho Power		
Weatherization Loans - 6 1/2%	99,737	.590
Cascade Natural Gas		
Weatherization Costs	(13,455)	(.063)
Commercial Weatherization	2,040	.010
Utility Commitment for Rate Reductions		
Portland General Electric		
Nuclear Fuel Storage Collection *	(5,986,748)	(.905)
BPA Weatherization Refunds	(929,000)	(.140)
Northwest Natural Gas		
Special Purchase Gas Savings	(131,993)	(.049)
Special Purchase Gas Savings	(706,981)	(.260)
Cascade Natural Gas		
Self-Help Gas Cost Credit - 1985	(41,662)	(.195)
Self-Help Gas Cost Credit - 1986	(189,464)	(.887)

*If this account had not been amortized to offset interim Colstrip No. 4 costs, the balance would have been about $(33.4) million.

Notes:

1) If a deferred account had been authorized to accumulate Portland General Electric's Colstrip No. 4 costs, the balance at year-end 1986 would have been about $27.4 million.

2) As of March 1, 1987, Pacific Power & Light began voluntarily to defer for the ratepayers' benefit rate reductions arising from the Tax Reform Act of 1986 in the approximate annual amount of $(13.2) million.

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ENERGY UTILITY DEFERRED DEBIT/CREDIT ACCOUNTS

The amount shown after the account number and title of each deferred account represents the balance in that account as of December 31, 1986. Bracketed amounts represent credit balances; unbracketed amounts are debit balances. Deferred credit balances can reduce rate levels; deferred debit balances can increase them.

ELECTRIC UTILITIES

PORTLAND GENERAL ELECTRIC COMPANY (PGE)

186 (D95015) Regional Power Act (RPA) Balancing Account $18,758,783

This account was established in October 1981 as a result of Docket UF 3733. A September 29, 1981, letter from the OPUC outlined the accounting treatment for the Regional Exchange Program with BPA. PGE was directed to set up a balancing account, the balance of which represents the difference between exchange benefits received by the company from BPA and the benefits which have been paid to PGE's customers through its RPA Exchange Credit (Schedule 102). The current Schedule 102 credit includes a 0.06 cent reduction in the credit to customers in an effort to amortize the balance in the account owing to PGE.

186 (D95127) Institutional Buildings Program (IBP) Expense Deferral $660,000

Pursuant to OPUC Order No. 85-497 (June 4, 1985) in which the Commissioner approved the electric utilities' accounting treatment for IBP expenses, PGE is accumulating actual program costs plus interest in this deferred debit account. The balance will be amortized in rates during a future time period.

232 (J15111) Power Cost Adjustment (PCA) Balancing Account ($3,563,000)

Pursuant to OPUC Order No. 79-830 (UF 3518), PGE implemented a power cost adjustment (PCA) in rates effective November 15, 1979. Tariff Schedule 100 imposes a rate adjustment calculated quarterly which reflects eighty percent of the estimated increase or decrease in power costs from expected power costs. Order No. 79-830 requires PGE to accumulate amounts over- or undercollected from previous quarters in a PCA account with accumulated revenue balances to be amortized in subsequent quarters through an adjustment to the Schedule 100 PCA rate.

186 (D95118) Capital Restructuring Program Cost Deferral $14,258,566

PGE established this account pursuant to OPUC Order No. 85-824 (UF 3965) in which the Commissioner approved PGE's application for authority to issue long-term debt as a part of its capital restructuring program on September 10, 1985. The order directed PGE to accumulate both gains and losses associated with the company's ongoing program in a deferred account. Any net balance in the account at the conclusion of the program (no longer than four years from the date of the order) is to be amortized in rates over a future five-year period.

186 (D95999) State Tax Normalization Deferral $517,000

An OPUC letter dated December 11, 1984, approved PGE's proposal to defer additional taxes resulting from a state tax law change requiring additional tax normalization for property placed in service after October 19, 1983. Additional taxes were deferred in this account effective October 19, 1983, with the balance to be amortized over the test period utilized in PGE's next general rate filing. The balance is not currently being amortized.

253 (K88100) Boardman Sale Gain Deferral ($96,605,174)

In OPUC Order No. 85-1236 (UP 30) dated December 23, 1985, the Commissioner approved PGE's application to sell part of its interest in the Boardman Coal Plant and associated transmission facilities and part of its interest in the Pacific Northwest Intertie. The sale resulted in a gain of $102,440,000, net of related income taxes of $61,113,000. Generally accepted accounting principles require that $27,865,000 of the gain be deferred and amortized over the three-year period that the company is subleasing back Boardman and that the remaining $74,575,000 be recognized in income currently. However, the Commissioner directed PGE to defer 50 percent of the gain pending final disposition of the entire gain in the company's current rate case, Docket UE 48. PGE deferred the entire Boardman gain in this account. In January 1986, PGE began amortizing $13,933,000 (half of the $27,865,000 deferred gain) over a three-year period pending final disposition of the UE 48 rate case.

253 (K88011) Columbia-Willamette Development Co. (CWDC)
Property Sales Gain Deferral ($2,333,750)

During 1985, the OPUC approved three property sale transactions between PGE and CWDC, a wholly owned subsidiary. In Order No. 86-150 (February 20, 1985), the Commissioner directed PGE to place the amount of the gains on the sales in a deferred credit account until the company's next rate case. The balance is not currently being amortized. Disposition of the gains is an issue in the current rate case, Docket UE 48.

186 (D95018) Pole Inspection Program Expense Deferral $883,761

OPUC Order No. 82-451 dated June 21, 1982, approved PGE rates which became effective on May 7, 1981, based on the rate recommendations of a Touche-Ross audit of PGE previously ordered by the Commissioner. The Touche-Ross report recommended that the costs of a comprehensive pole replacement program which began in 1980 be deferred and amortized over a 10-year period. PGE established this account pursuant to the Commissioner's acceptance of the Touche-Ross recommendations. The account balance is being amortized over 10 years beginning in 1982.

253 (K89011) Nuclear Fuel Storage Collection ($5,986,748)

This account was established in January 1979 for the purpose of recording amounts collected in rates for expected future payments to the Department of Energy (DOE) for permanent disposal of spent nuclear fuel from the Trojan Nuclear Power Plant. PGE has been overcollecting in rates the amount due the DOE for fuel utilized prior to April 7, 1983. Pursuant to Order No. 86-586 (UE 47), the Commissioner is allowing PGE to amortize, on a monthly basis, sufficient excess reserve in this account to offset costs associated with PGE's investment in the Colstrip Unit 4 Steam Generation Plant. The amortization is allowed on an interim basis, subject to refund.

PGE Weatherization Programs

186 (D95016) Water Heater Program (WHIP) Admin. Indirect $924,000

This program was offered to residential customers over the period 1981 through 1985. The costs of administering the program are currently being amortized over 10 years.

186 (D95021) Weatherization Program - Administrative Costs $22,000

This account was established in 1979 to accumulate the current month's indirect costs of administering PGE's weatherization programs. The balance is subsequently transferred to Account D95049 for amortization.

186 (D95022) State Mandated Weatherization Rebate Program $226,000

This legislatively mandated rebate program operated from 1983 through 1986. A 10-year amortization of the program costs began in 1984.

186 (D95025) Commercial/Industrial Energy Management Program $987,000

This account records all costs necessary to provide information and technical assistance for commercial and industrial audits for conservation measures. This program, mandated by Senate Bill 111, began in 1981. A 10-year amortization of the program costs also began in 1981.

186 (D95038) Water Heater Wrap Program - Summer Blitz $81,000

This account recorded the costs associated with a one-time water heater wrap program which was offered in the summer of 1981. Costs of the program are being amortized over 10 years beginning in 1982.

186 (D95039) Water Heater Incentive Program - Direct Incentives $392,000

This program operated from 1981 to 1986. A 10-year amortization of program costs began in 1981.

186 (D95041) Water Heater Wrap Program $355,000

This account records the costs of PGE's on-going water heater wrap program which began in 1983. Program costs are being amortized over 10 years beginning in 1983.

186 (D95042) Low Income Weatherization Program $140,000

This program, which began in 1985, offers rebates to community agencies to be disbursed to low income PGE residential customers for installation of weatherization measures. Program costs are being amortized over 10 years beginning in 1986.

186 (D95048) Write-Off of Uncollectible Weatherization $586,000

This account records the costs associated with uncollectible weatherization loans. The 10-year amortization of these costs began in 1983.

186 (D95049) Unamortized Indirect Costs - Weatherization Program $4,944,000

Costs in this account have been transferred on a monthly basis from Account D95021 for amortization over a 10-year period. Amortization of this account began in 1981.

186 (D95116) BPA Weatherization Refunds ($929,000)

This account reflects the balance of several refunds from BPA for a weatherization rebate program offered by PGE in the early 1980's which was partially subsidized by BPA. The account balance is being refunded to customers over a 10-year period beginning in 1982.

CP NATIONAL CORPORATION (CPN) - ELECTRIC

186.14 Regional Power Act (RPA) Balancing Account ($825,464)

This account was established October 1, 1981, as a result of Docket UF 3742. A September 29, 1981, letter from the OPUC outlined the accounting treatment for the Regional Exchange Program with BPA. Participating electric utilities were directed to set up a balancing account, the balance of which represents the difference between exchange benefits received by the utility from BPA and the benefits which have been paid to the utility's customers through its regional act credit adjustment. OPUC Order No. 86-1211, resulting from Docket UE 54/55 required that the $650,350 credit balance in CPN's RPA balancing account at October 31, 1986, be returned to residential and small farm customers through rates over a 12-month period beginning November 26, 1986.

186.75 Inverted Rate Balancing Account ($374,031)

This account was also authorized by the September 29, 1981, letter from the OPUC referred to above. The purpose of the account was to accumulate differences in revenues occurring as a result of redesigning CPN's flat rate structure to inverted rates. An October 31, 1983, letter from the OPUC resulting from CPN's general rate case (UE 14) authorized the company to recover the August 31, 1983, balance owed by customers over a 12-month period. Because rates did not change after the 12-month amortization period, CPN had been overcollecting on this account. OPUC Order No. 86-1211, resulting from Docket UE 54/55, ordered the termination of accruals to the account and the amortization of the $355,386 account balance owing to customers over a 12-month period beginning November 26, 1986.

186.99 CSPP Deferrals $2,480,726

OPUC Order No. 86-147 authorized CPN to defer the excess costs associated with purchasing power from cogeneration and small power producers (CSPP) beginning February 20, 1986. OPUC Order No. 86-1211 (UE 54/55) required that CPN terminate accruals in the CSPP deferred account and amortize the $2,108,598 balance over a 12-month period beginning November 26, 1986.

PACIFIC POWER & LIGHT COMPANY (PP&L)

253-20 W.O. 00010-12 Regional Exchange Balancing Account ($353,129)

This account was established October 1, 1981, as a result of Docket UF 3735. A September 19, 1981, letter from the OPUC outlined the accounting treatment for the Regional Exchange Program with BPA. PP&L was directed to set up a balancing account, the balance of which represents the difference between exchange benefits received by the company from BPA and the benefits which have been paid to PP&L's customers through its regional act credit adjustment (Schedule 98). PP&L attempts to zero any balance present in the account when new tariffs are filed through the use of a balancing account adjustment to the Schedule 98 credit included in those tariffs.

186-30 W.O. 00001-21 Recapitalization Program $1,651,993

This account was established September 26, 1984, as a result of OPUC Order No. 84-760 (Docket UF 3940). PP&L was ordered to accumulate both gains and losses associated with the company's ongoing recapitalization program in a deferred account. Any net balance in the account at the conclusion of the program (no longer than four years from the date of the order) is to be amortized through rates over a future five-year period.

173-10 W.O. 00003 Institutional Buildings Program ($1,025,933)

As a result of OPUC Order No. 85-497 (June 4, 1985) concerning the accounting for the Institutional Buildings Program (IBP) mandated by the Commissioner, PP&L bills customers at a specified millage rate for estimated IBP expenditures. The difference between actual expenditures and the amount of IBP revenues collected by the company through rates is accumulated, with interest, in this accrued utility revenue account to be reflected in rates when the Commissioner authorizes it in the future.

173-10 W.O. 00005 Colstrip Unit 4 Deferred Revenues $5,876,741

In OPUC Order No. 86-411 (Docket UM 113), the Commissioner approved PP&L's proposed accounting treatment related to its investment in Colstrip Unit 4 Steam Generation Plant. On April 23, 1986, PP&L began recording deferred revenue associated with Colstrip Unit 4 until the time when the costs associated with the investment would be included in billings. Pursuant to OPUC Order No. 86-605, effective June 23, 1986, PP&L was allowed to place its share of Colstrip Unit 4 in rate base on an interim basis and to accrue revenue and defer billing for the increased costs until the Commissioner issued a final order in the UE 52 proceeding. That order (No. 87-034), issued January 8, 1987, allowed the company to increase permanent rates to recover the ongoing costs associated with Colstrip Unit 4 and to amortize the deferred revenue balance accumulated from June 23, 1986, through January 8, 1987, over a one-year period. The $2,078,555 balance accumulated in the account before June 23, 1986, was not allowed to be recovered in rates. (The balance shown above does not include the amount disallowed.)

173-10 W.O. 00006 Jim Bridger Unit 2 Pollution Control Equipment Deferred Revenues $1,788,555

OPUC Order No. 86-1078 (UE 52) authorized PP&L to include in its rate base on an interim basis its investment in Jim Bridger Unit 2 flue gas desulfurization system and to defer billing and collection of associated revenues, effective October 1, 1986. OPUC Order No. 87-034 authorized the amortization of the balance in this account as of January 8, 1987, in rates over a one-year period.

186-20 W.O. 10081-85 Weatherization Loan Program - Zero Percent Interest $3,705,907

The Zero Percent Interest Weatherization Loan Program was implemented by PP&L's tariff Schedule 8, effective August 7, 1978. Indirect costs associated with the program have been accumulated in this deferred debit account and are being amortized to expense over a 10-year period.

186-20 W.O. 10681-85 Weatherization Loan Program - 6 1/2 Percent Interest $458,857

The 6 1/2 Percent Interest Weatherization Loan Program was mandated by Oregon legislation in 1981. PP&L's program was implemented September 1, 1978, through tariff Schedule 9. Indirect costs associated with this program have been accumulated in this account and are being amortized to expense over a 10-year period.

186-20 W.O. 13082 Weatherization - Residential Water Heater Wrap Program $38,325

PP&L implemented the Residential Water Heater Wrap Program through tariff Schedule 9, effective September 1, 1978. Expenditures for the water heater wraps, as well as the indirect costs of the program, have been accumulated in this account and are being amortized to expense over a 10-year period.

186-20 W.O. 00296 Commercial Energy Conservation Program $340,115

The Commercial Energy Conservation Program was mandated by Senate Bill 111. The costs associated with this program have been accumulated in this account and will be amortized over a future three-year period.

186-20 W.O. 00262 Hood River Conservation Program ($8,521)

Through an agreement with BPA, PP&L conducted a conservation program in the Hood River area designed to develop intensively the residential retrofit conservation potential of a limited geographic area over a relatively short period of time and within the framework and priorities established under the Regional Act. The nonreimbursable costs of this program have been accumulated in this account and are being amortized to expense over a three-year period.

186-20 W.O. 00273 Unamortized Nuclear Waste Disposal Costs $228,408

The Nuclear Waste Disposal Act of 1982 required utilities owning nuclear power plants to enter into contracts with the Department of Energy (DOE) for permanent disposal of Spent Nuclear Fuel (SNF).

Those contracts provide for a fee based on specified rates per kwh. In the case of the Trojan Nuclear Power Plant, of which PP&L owns a 2.5 percent interest, those fees have been broken into two components: 1) those for fuel utilized prior to April 7, 1983; and 2) those for fuel utilized after that date. The latter are being recovered through an assessment of 1.0 mill/gross kwh. Unlike PGE, PP&L had not been charging expense for disposal of SNF used before April 1983. PP&L's share of the contract fees for SNF utilized prior to April 7, 1983, have been booked to a deferred debit account and are being amortized over a three-year period.

IDAHO POWER COMPANY (IPCo)

<u>186.766 CSPP Deferrals</u> $545,465

OPUC Order No. 85-694 authorized IPCo to defer the Oregon portion of the net excess costs associated with purchasing power from cogeneration and small power producers (CSPP) beginning July 31, 1985, until its next general rate case. OPUC Order No. 86-950, resulting from IPCo's UE 43 general rate case, required the discontinuation of further CSPP expense deferral and the amortization of accumulated deferred CSPP expenses into rates over a three-year period beginning September 16, 1986.

<u>186.803 Weatherization 6 1/2 Percent Interest - Oregon</u> $99,737

The 6 1/2 percent interest weatherization program was mandated by Oregon legislation in 1981. OPUC Order No. 81-778 adopted OAR 860-30-035, which specifies how costs of the program will be accounted for by the utilities. The rule requires that all indirect costs of the program be placed in a deferred debit account until the Commissioner issues an order to include the appropriate amount of indirect costs in rates. The Commissioner has not yet issued an order to amortize the amount that has accumulated in IPCo's deferred 6 1/2 percent interest weatherization account since its program was implemented in 1981.

<u>186.809 Institutional Buildings Program - Oregon</u> $42,454

OPUC Order No. 85-010 (January 1985) directed that the Institutional Buildings Program (IBP) be established in the electric investor-owned utility service territories. OPUC Order No. 85-497, issued June 4, 1985, approved the proposed accounting treatment for program costs for each of the utilities. The Commissioner approved IPCo's proposal to accumulate IBP costs plus interest in a deferred debit account. The balance in the account will be amortized in rates during a future time period.

GAS UTILITIES

Unrecovered Purchased Gas Cost Accounts

The Federal Energy Regulatory Commission (FERC) authorizes certain gas cost changes to be deferred by interstate pipelines in 191 accounts between changes in annualized wholesale gas rates. Similarly, the OPUC allows gas distribution companies to defer changes in wholesale gas costs for subsequent amortization into retail gas rates, pursuant to OPUC tracking Order Nos. 79-226 and 79-249, certain general rate case orders, tariff approval letters signed by the Utility Director, and ad hoc letters signed by the Energy Division Manager. These gas cost deferrals (which are booked in 191 subaccounts for Northwest Natural Gas Co. and CP National Corp., and in 186 and 253 subaccounts for Cascade Natural Gas Corp.) represent Northwest Pipeline Corporation cash refunds or billing credits, spot market gas savings, and annualized wholesale gas rate changes which are not practical to track immediately into retail rates.

NORTHWEST NATURAL GAS COMPANY

Interruptible Sales Adjustment (ISA) Accounts

Northwest Natural established its Interruptible Sales Adjustment (ISA) accounts as a result of its general rate case, UF 3798, beginning April 1, 1982. Schedule 170, the Interruptible Sales Adjustment, is designed to mitigate the effects of interruptible sales volatility on both the company and its customers. Eighty percent of the difference between revenues based on actual interruptible gas sales and revenues based on expected interruptible sales levels are credited or debited to a deferred ISA account monthly. The balance accumulated in the account over a 6- to 12-month period (either owing to the company or to the customers) is amortized to rates over a specified period following the company's approved gas cost tracking filing.

186.139 ISA Deferral — $5,610,833

This account was charged with the most recent monthly accumulations under Northwest Natural's Schedule 170. $2,872,431 of the account balance is currently being amortized in rates over a 10-month period beginning January 1, 1987.

186.165 ISA Deferral — $229,755

The balance in this account represents the 1985 ISA accumulation and 1984 residual ISA accumulation, which are currently being amortized in rates over a four-month period beginning January 1, 1987.

186.169 ISA Amortization $987,069

The balance in this account represents ISA accumulations from August 1985 through January 1986, which are currently being amortized in rates over a four-month period beginning January 1, 1987.

Temperature-Sensitive Sales Adjustment (TSSA) Accounts

Northwest Natural created the TSSA Contribution Account and the TSSA Balancing Account under the Procedure for the Experimental TSSA Adjustment approved with Schedule 171 in an OPUC letter dated April 17, 1984. The TSSA tariff was effective on May 1, 1984, and remained in effect until May 31, 1986, when it was terminated as one element of the stipulation and agreement in Docket UG 38. The TSSA Adjustment was designed to reflect differences from expected sales levels for residential class gas sales resulting from deviations from normal weather conditions.

186.156 and 186.170 TSSA Balancing Accounts ($554,615) and ($689,436)

The balances in these accounts reflect unamortized accumulations to the TSSA Account over the period the TSSA Adjustment was in effect. A $1,316,355 net credit balance is currently being returned to customers in rates over a four-month period beginning January 1, 1987.

186.155 TSSA Contribution Account ($731,407)

The purpose of the TSSA Contribution Account was to act as a cushion against potential rate surcharges in the event that weather was abnormally warm during the two-year experimental period for the TSSA and substantial debit balances built up in the TSSA Balancing Account to be collected from customers. The company credited $1,000,000 to the account during the first TSSA heating season, with the balance accruing interest thereafter. Because this account was no longer needed for its intended purpose, on November 17, 1986, the OPUC granted Northwest Natural's request to transfer the credit balance in the account to a subaccount of Account 495, Miscellaneous Revenues, in eight monthly installments between October 1986 and May 1987.

186.40 Uncollectible Weatherization Contracts ($8,709)
186.172 (Throop) Weatherization Survey Costs $220,126

The costs related to these legislatively mandated programs have been deferred. Account 186.172 is currently being amortized in rates over a 10-month period beginning January 1, 1987. Account 186.40 expense was temporarily disallowed by OPUC in the January 1, 1987, tracking.

186.163 Deferred Steam Heat Balancing Account $92,535

This account was established pursuant to OPUC Order No. 85-386, resulting from Northwest Natural's general rate case (UG 28). Monthly entries into this account were made to reflect differences in revenues from those used to set rates which are related to the phase-out of Pacific Power & Light Co.'s steam heat system over the period May 1, 1985-March 31, 1986. The residual balance is currently being refunded to customers over a four-month period beginning January 1, 1987.

186.171 1986 Leakage Reconstruction Program Deferred Account $1,214,903

This account was established pursuant to OPUC Order No. 86-500, resulting from the company's 1986 general rate case (UG 38). Northwest Natural was directed to debit this account monthly with the Oregon revenue requirement associated with the costs of the 1986 Leakage Reconstruction Program reported for the previous month at the rate of 18.062 cents per dollar of direct program costs. The order states that the balance in this account, not to exceed $1,531,000, will be amortized in rates over 12 months beginning October 1, 1987.

186.168 Interim Rate Increase Deferred Account $517,768

OPUC Order No. 86-180 (UG 38) authorized the company interim rate relief effective March 1, 1986. However, March revenues were to be deferred and amortized over 12 months beginning April 1, 1986. The residual balance in this account is currently being amortized in rates over a four-month period beginning January 1, 1987.

186.174 Transportation Increment $156,044

This account was set up by the company to correct for prior period errors due to omission of transportation volumes in deferred account balance calculations. The balance in this account is currently being amortized in rates over a four-month period beginning January 1, 1987.

191 Accounts

All of the 191 account balances listed below are currently being amortized in rates over 4- or 10-month periods beginning January 1, 1987, pursuant to approval of Northwest Natural's gas tracking increase (UG 49).

191.53 Northwest Pipeline Refund $304,988

This account reflects the unamortized balance of the Pipeline refund associated with the Pipeline's 1982 general rate case, which began to be tracked in rates May 1, 1985.

191.56 Northwest Pipeline IS-1 Savings ($172,945)

This account reflects the unamortized balance of deferred gas cost savings associated with the Pipeline's IS-1 rate, as specified in Docket UG 28.

191.64 Northwest Pipeline D-1 Charge $46,645

This account reflects gas cost savings resulting from a decrease in the Pipeline's May 1, 1985, D-1 Charge which were deferred by the company until October 1, 1985.

191.72 Northwest Pipeline Demand Charge Credit ($452,731)

This account reflects the deferral of demand charge credits due to the Pipeline's off-system gas sales.

191.78 Deferred Cost of Gas Amortization ($65,331)

This account reflects the consolidated balances of accounts 191.63, 191.66, 191.68, and 191.70, which began being amortized in rates May 1, 1986.

191.79 Special Purchase Gas Savings ($131,993)

This account reflects the savings associated with special purchases of gas made prior to the May 21, 1986, settlement date of Northwest Natural's 1986 general rate case UG 38.

191.80 Special Purchase Gas Savings ($706,981)

This account reflects the savings associated with special purchases of gas made between May 21 and July 31, 1986.

191.81 Cost of Gas Amortization ($274,755)

This account was established to amortize the balance of Account 191.74, which deferred the April 1, 1986, Pipeline tracking decrease for the month of April 1986.

191.82 Northwest Pipeline Refund ($69,663)

This account reflects two refunds from the Pipeline in settlement of FERC Order No. 399-B.

191.84 Northwest Pipeline Section 104 Refund ($266,359)

This account reflects the total of Pipeline Section 104 refunds.

191.87 Deferred Gas Cost Decrease ($435,431)

This account reflects the savings due customers associated with the delayed tracking of the April 1, 1986, gas cost decrease from May 1, 1986, through May 20, 1986.

191.88 Deferred Gas Cost $318,520

This account reflects the difference between actual ODL-1 commodity costs (24.643 cents/therm) and UG 38 commodity costs (22.363 cents/therm) for the period May 21, 1986, through July 31, 1986.

191.89 CIG Refund ($504,608)

This account reflects a pipeline refund stemming from the settlement with Colorado Interstate Gas (CIG) in FERC Docket No. RP 84-59.

CASCADE NATURAL GAS CORPORATION (Cascade)

1860-148 Oregon Weatherization Costs ($13,455)

The balance in this account represents the residual balance of previously amortized costs of Cascade's mandated residential weatherization program in its Oregon service area. This account is also used to monitor the ongoing costs of the weatherization program. Costs are initially charged to this account, then transferred each month to Account 908.

1860-166 Oregon Water Heater Program $68,930

The balance in this account represents the unamortized balance of the cost of water heater rebates issued to Cascade's Oregon customers under a program approved by the OPUC in 1981. The program was discontinued in the Spring of 1985 pursuant to OPUC Order No. 85-010. The remaining balance in this account is being amortized over a 10-year period.

1860-174 Oregon Commercial Weatherization Costs $2,040

This account is charged with the costs of Cascade's commercial weatherization program. There have been no accounting procedures established to date to amortize the balance in this account.

1860-213 Astoria Cleanup Costs $315,000

This account was set up by Cascade to contain the company's costs associated with the settling of its portion of the liability for the cleanup of the site of a former manufactured gas plant that was once operated by one of Cascade's predecessors. No decision has been made as to the ultimate accounting treatment of these costs.

2530-043 Oregon Deferred Self-Help Gas Cost Credit - 1985 ($41,662)

This account was credited with the amount of gas cost savings which resulted from Cascade's purchases of system-supply gas from sources other than its primary supplier in 1985. These savings are currently being refunded to customers under Rate Schedule 194.

2530-052	Oregon 8/1/86 Gas Cost Decrease	($177,630)

This account is credited monthly with the one cent per therm which was withheld from the company's August 1, 1986, gas cost tracking rate reduction. The estimated December 31, 1986, balance is currently being amortized in rates over 12 months beginning January 8, 1987.

2530-050	Oregon Deferred Self-Help Gas Cost Credit - 1986	($189,464)

This account was credited with the amount of gas cost savings which resulted from Cascade's purchases of system-supply gas from sources other than its primary supplier in 1986. It is anticipated that these savings will be refunded to customers by means of a future rate reduction.

2530-045	Northwest Pipeline Demand Charge Credit	($53,683)
2530-047	1986 Northwest Pipeline Refunds	($69,313)
2530-056	Northwest Pipeline Commodity Decreases (11/86, 12/86, 1/87)	($63,261)

These accounts are credited with various refunds and credits received from Northwest Pipeline Corp. The estimated December 31, 1986, balance of Account 2530-045 is currently being amortized in rates over a four-month period beginning January 8, 1987. The balances in Accounts 2530-047 and 2530-056 will be refunded to customers by means of a future rate reduction.

2530-033	Oregon Gas Cost Reduction Credit (4/85)	$33,436
2530-034	Oregon 5/85 Technical Adjustment No. 1	$13,181
2530-035	Oregon 5/85 Technical Adjustment No. 3	$3,454
1860-204	Oregon 5/85 Technical Adjustment No. 2	($2,865)
2530-040	Oregon 7/1/85 Gas Cost Decrease	($1,319)

These accounts represent residual balances of prior Pipeline refunds and credits, and the results of delayed tracking of Pipeline gas cost changes. These items had been previously passed on to customers through temporary rate adjustments. At the expiration dates of these temporary rate adjustments, there were either residual debit or credit balances in these accounts. The net balance of these accounts is currently being collected from customers over a four-month period beginning January 8, 1987.

1860-215	November 1, 1986, Oregon Demand Cost Increase	$14,283

This account was set up to accumulate the increased costs associated with the Pipeline's November 1, 1986, demand charge increase.

CP NATIONAL CORPORATION (CPN) - GAS

186.13 $150 Water Heater Rebate Deferral $62,376

CPN began offering a $150 water heater rebate program with OPUC tariff approval in 1981. The costs associated with the program were deferred in this account with amortization to occur over a 10-year period. In the January 8, 1985, Order No. 85-010 (AR 112), the Commissioner directed the gas utilities to discontinue their water heater incentive programs. The balance in this account is being amortized over a 10-year period.

186.74 Interruptible Sales Balancing Account ($28,426)

CPN's Interruptible Sales Balancing Account (ISA) was established as a result of OPUC Order No. 81-673 (UF 3695) in September 1981. The purpose of this account is to protect the utility and its customers from under- or overcollection of revenues due to the volatility of interruptible sales. Eighty percent of the difference between revenues based on actual interruptible gas sales and revenues based on expected interruptible sales are credited or debited to the account monthly. The balance accumulated in the account over a 6- to 12-month period (either owing to the company or to the customers) is amortized to rates over a 12-month period following the company's filing of rate changes.

186.73 Northwest Pipeline Refund ($66,989)

This account represents a refund CPN collected from Northwest Pipeline Corporation (Pipeline) for overbilling as the result of a FERC order. CPN began amortizing the balance due to customers in April 1985 and will continue until fully amortized.

186.73 CIG Surcharge Refund ($51,796)

The balance in this account reflects the net effect of a Pipeline refund resulting from settlement of FERC Docket RP 84-59 [1983 minimum bill settlement from Colorado Interstate Gas (CIG)] and a CIG demand charge surcharged to the company. The balance is currently being refunded to customers over a four-month period beginning December 1, 1986.

186.76 Incentive Sales (I.S.) Overcollection ($21,293)

This account represents the overcollection from customers resulting from CPN purchases of lower-priced gas since April 1, 1986. The balance is currently being refunded to customers over a four-month period beginning December 1, 1986.

191.71 Incentive Gas Overcollection ($10,078)

This account, similar to the I.S. Overcollection above, is being refunded to customers over a 12-month period beginning April 1, 1986.

186 Interim Commodity Cost Balancing Account ($81,197)

This account reflects the savings resulting from purchasing gas from suppliers other than Northwest Pipeline Corporation and transporting that gas across the Pipeline's system. The balance is currently being refunded to customers over a four-month period beginning December 1, 1986.

186 Northwest Pipeline 11/1/86 Decrease ($88,328)

This account represents the one-month accumulation of overcollection from customers due to the Pipeline's November 1, 1986, rate decrease not passed on in CPN's rates. The balance is currently being refunded to customers over a four-month period beginning December 1, 1986.

kwc/8832H

OREGON HOUSE OF REPRESENTATIVES

Bill No. HB 2145 Pages Date JUN 0 9 1987 PM
Presented by Staff

LEGISLATIVE SESSION - 1987

STAFF MEASURE ANALYSIS

Measure: HB 2145

Title: Relating to public utilities; and declaring an emergency

Committee: House Environment and Energy

Hearing Dates: 3/11/87, 3/25/87, 3/30/87, 4/8/87

Explanation prepared by: Carol Kirchner, Administrator

PROBLEM ADDRESSED. Utility rates are set for the future. Rates set today, in effect, are a forecast of expected utility expense and revenue for a given period. Utilities cannot ask for an increase in rates to make up for costs not projected. There are certain instances where unanticipated costs cannot be known well enough in advance to project them in a formal rate case. Conversely, benefits may accrue that were otherwise not anticipated. To accommodate these situations, the PUC has allowed deferral of costs and revenues which were subsequently included and considered in setting rates in formal rates cases.

On March 11, 1987, the Attorney General issued an opinion that calls into question the authority of PUC, on its own order, to effectively make "rates retroactively" without specific statutory direction.

FUNCTION AND PURPOSE OF MEASURE AS REPORTED OUT. HB 2145 directs that the PUC may defer utility expenses or revenues in certain circumstances and include such deferrals in a formal rate case. Deferral applications may be made by the utility, the PUC, or a ratepayer. In any one year, the impact of the collection or refunding (amortization) shall not exceed 3% of the utility's gross revenue. Qualifying circumstances include: orders retroactively imposed by another government agency; changes in wholesale price of power; balances allowed under the Regional Power Act; and to minimize fluctuations of rates. Amounts previously deferred under PUC order are allowed to stand but must be reauthorized to continue. An emergency is declared.

MAJOR ISSUES DISCUSSED. The exact dimensions of the "unanticipated" events to insure they are not abused; recognizing unanticipated benefits, as well as costs; previous PUC orders; and allowing public comment on applications.

EFFECT OF COMMITTEE AMENDMENTS. Includes refund of unplanned-for revenues in rates; application by PUC or a ratepayer; interest on approved deferrals to be set by PUC;authorizes previous PUC orders, subject to continued reauthorization; sets limit on rate impact and declares an emergency.

COMMITTEE VOTE. The bill received a 7-2 do pass recommendation, as follows: AYE: Barilla, Eachus, Gilman, Parkinson, Peterson, Sowa and Cease. NO: Anderson and Johnson. CARRIER: Eachus

Note: This analysis is intended for information only and has not been adopted or officially endorsed by action of the committee.

Legislative Counsel
HB 2145A-6
(Amend.)
6/10/87 (ky)

PROPOSED AMENDMENTS TO A-ENGROSSED HOUSE BILL 2145

On page 1 of the printed A-engrossed bill, line 21, after the period insert "A deferral may be authorized for a period not to exceed twelve months after the date of application.".

On page 2, after line 4, insert:

"(7) Amounts that have accrued in deferred accounts and amortized in rates since November 15, 1986, in excess of the limit established under subsection (6) of this section, shall be:

"(a) Refunded to ratepayers; and

"(b) Subject to the standards and procedures of subsections (4) to (6) of this section.

"<u>SECTION 3.</u> Section 4 of this Act is added to and made a part of ORS 756.500 to 756.610.

"<u>SECTION 4.</u> (1) The commission may award reasonable attorney fees, expert witness fees and other costs of participation or intervention in a hearing or proceeding held for the purpose of establishing or modifying a public utility rate, or establishing a fact or adopting a rule that may influence a public utility rate, to the Citizens' Utility Board or any other person who so participates or intervenes.

"(2) The commission may make the award referred to in subsection (1) of this section if the commission finds that the information presented makes a substantial contribution to the adoption, in whole or in part, of any order or decision of the commission.

"(3) The award referred to in subsection (1) of this section shall be an order by the commission directing the public utility that is a party to the hearing or proceeding to pay the award.".

In line 5, delete "3" and insert "5".

****

SENATE BUSINESS, HOUSING AND FINANCE
HB 2145
Exhibit P Pages 2
Presented by Charles Davis Date JUN 11 1987 for the record

NEIL GOLDSCHMIDT
GOVERNOR

PUBLIC UTILITY COMMISSION OF OREGON

LABOR & INDUSTRIES BUILDING, SALEM, OREGON 97310 PHONE (503)
378-6611

June 10, 1987

Senator Jim Hill, Chair
Senate Business, Housing & Finance Committee
S306 State Capitol
Salem OR 97310

Re: HB 2145 - Utility Deferred Accounting and Ratemaking

At the meeting of your committee on the afternoon of June 9, 1987, an amendment to HB 2145 was proposed by a representative of Boise Cascade Corporation (Boise). The amendment would read as follows:

> Add a new subsection (7) to section 2 of HB 2145:
>
> (7) Amounts accrued in deferred accounts and amortized in rates since November 15, 1986 in excess of the limitation contained in subsection (6) of this section shall be refunded to ratepayers and shall be subject to the standards and procedures of subsections 4 to 6 of this section.

We oppose the amendment. It appears the sole purpose of the amendment is to require by statute that a matter at issue in a pending CP National Corporation electric utility rate case be resolved in Boise's favor. Boise is, of course, a party actively involved in the rate proceeding. It had, and to the extent permitted by fairness to all parties, still has, an opportunity to present its arguments on this issue before the Public Utility Commission. The Commission has an obligation to resolve the matter in a fair and reasonable way, considering all interests involved.

Moreover, the existing statutes which apply to Commission activities appear to allow the result Boise seeks. Under ORS 757.215, interim rate changes, such as those now in effect for CP National, are subject to refund. If the Commission is persuaded by Boise's position, it can make the retroactive changes sought by the amendment.

In addition, we believe it to be poor practice to circumvent the established process in a relatively complex technical matter by a statutory provision with such narrow application. The provisions of the amendment are apparently intended to apply to the rates of one company for the period from November 15, 1986 to the date of enactment of this bill. The PUC rate-setting process is better able to reach a resolution in the matter which is fair to all parties.

Also at yesterday's session of your committee, a question arose as to the effect of the Cohen amendment. That amendment added a new sentence, as follows, to Section 2 (3) of the bill:

> Deferrals may be authorized for a period not to exceed twelve months from the date of application.

We believe the new language would allow creation of deferred accounts for a period as long as one year following an application to the Commission. Amortization of the deferrals, i.e., inclusion of costs or benefits in customers' rates would take place subject to the requirements in Sections 2 (4) through 2 (6) of the Act. If additional deferrals in connection with a particular matter are appropriate beyond the one-year limit, another application would be required. However, amortization could take place over more than one year, particularly through application of the 3 percent annual rate cap in Section 2 (6).

We believe the Bill, as amended by your committee on June 9, is in reasonable form, and we urge its adoption.

Charles Davis

Charles Davis
Commissioner

nh/4083F

cc: Commissioner Paul Cook
Commissioner Nancy Ryles
Senator Joyce Cohen
Senator William Frye
Senator Bill Kennemer
Senator Jim Simmons
Representative Ron Eachus
Mr. Roy Hemmingway, Boise Cascade

Exhibit 3405 has been retained and transmitted in its native format

Information provided in electronic format only

ITEM NO. 5

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: January 17, 2019

REGULAR ____ **CONSENT** X **EFFECTIVE DATE** **December 7, 2018**

DATE: January 8, 2019

TO: Public Utility Commission

FROM: Mitchell Moore MPM

JC for JE JC

THROUGH: Jason Eisdorfer and John Crider

SUBJECT: PORTLAND GENERAL ELECTRIC: (Docket No. UM 1986) Request for Authorization to use Deferred Accounting to support PGE's use of balancing accounts.

STAFF RECOMMENDATION:

Staff recommends the Commission approve Portland General Electric's (PGE or Company) request to authorize deferral of the variance between revenues and expenses associated with the Multnomah County Business Income Tax (MCBIT) for the 12-month period beginning December 7, 2018.[1]

Staff recommends the Commission approve PGE's request to authorize deferral of the variance between revenues and expenses associated with Energy Efficiency (EE) Customer Service for the 12 month period beginning December 7, 2018.

Staff recommends that the Commission deny PGE's request for a deferral of the Major Maintenance Accruals (MMAs) in this docket, as the Company already has a deferral application for these amounts, which is docketed as OPUC Docket UM 1915.[2]

Finally, Staff recommends that the Commission deny PGE's request for a deferral of the RPA Credit, as a deferral is not necessary in order to facilitate the current ratemaking treatment for the balancing account already in place.

[1] PGE filed this deferral at the request of Staff due to a change in understanding regarding the need for deferrals underlying certain types of balancing accounts.
[2] OPUC Docket No. UM 1915 – the Commission approved PGE's Initial Deferral at the May 8, 2018 public meeting in Order No. 18-517.

DISCUSSION

Issue:

Whether the Commission should approve PGE's request for authorization to use deferred accounting to support PGE's use of balancing accounts for the MCBIT, RPA Exchange Credit, MMA's, and EE Customer Service.

Applicable law:

PGE filed its application in accordance with 757.259 and OAR 860-027-0300. ORS 757.259(2)(e) authorizes the Commission to allow a utility to defer, for later ratemaking treatment, expenses or revenues in order to minimize frequency of rate changes or to match appropriately the costs borne by and benefits received by customers. OAR 860-027-0300 sets forth the requirements for applications to defer.

The Northwest Power Act, Section 839c(c)(3) provides that "[t]he cost benefits, as specified in contracts with the Administrator, of any purchase and exchange sale referred to in paragraph (1) of this subsection which are attributable to any electric utility's residential load within a State shall be passed through directly to such utility's residential loads within such State, except that a State which lies partially within and partially without the region may require that such cost benefits be distributed among all of the utility's residential loads in that State."

Analysis:

Background:
In the Spring of 2018, Staff had determined that there were a number of balancing accounts held by various utilities that rolled positive and negative balances forward to set future rates, and that balancing accounts that incorporate past costs and revenues into future rates may require a deferral. Since then, Staff has worked with the utilities to identify such accounts and to file deferral applications to support these accounts.

PGE has identified several balancing accounts that it believes require deferred accounting approval based on Staff's position on balancing accounts used to set rates with carry-forward balances.

Accordingly, PGE made this filing on December 7, 2018, requesting approval for deferred accounting for four separate balancing accounts. In its deferral application PGE states that the purpose of the deferral is to address occasions when there is a positive (debit) balance that is rolled forward within these balancing accounts. Staff would clarify that the deferral is to address *any* variance – positive or negative – between costs incurred and revenues collected.

Further, PGE proposes to aggregate the requirement of Order No. 17-511, which requires the Company to file an annual deferral associated with its MMAs, with other unrelated deferrals for current balancing accounts. This would avoid the need for the Company to file separate deferral applications to support each of the balancing accounts.

While Staff is sympathetic to the additional paperwork and process that accompany separate deferral filings, Staff believes that the Commission is required to evaluate each deferral application on its own merits, and apply numerous criteria from statute, rules and previous Commission Orders to determine the validity and appropriateness of each request. Condensing multiple types of accounts into a single deferral mechanism would make the process of evaluating and tracking deferral accounts too cumbersome. In the case of already established deferrals, such as the MMA deferral, Staff can find no benefit; to the contrary, condensing deferrals for multiple balancing accounts reduces transparency. Therefore, Staff requests that the Commission direct PGE to file separate deferral applications for each different *type* of balancing account.

<u>MCBIT deferral request</u>

The Company maintains a balancing account to accrue any difference between the Company's actual MCBIT expense and what is collected from customers. Each year, the Company makes an advice filing to adjust the rate to reflect the Company's projections of the MCBIT tax expense for the coming year, as well as incorporating any residual balance from the previous year.

The Company determines the MCBIT rate by forecasting its expected MCBIT tax liability for the next calendar year and adding this forecasted amount to the actual over- or under-collection of the prior year's MCBIT taxes. The total amount is divided by the forecasted revenues for Multnomah County to determine the final MCBIT rate.

Proposed Accounting:
PGE proposes to account for the expenses and revenues associated with the MCBIT by recording the deferral in FERC Account 242, (Current Regulatory Liability). MCBIT payments are debited to FERC Account 242 and credited to FERC Account 407.4 (Regulatory Credit). The amortization of MCBIT is credited to Account 242 and debited to account 407.4. Interest will accrue on the balance at the approved blended treasury rate.

Estimated Deferrals in Authorization Period:
PGE did not provide an estimate of the amounts to be deferred.

Information Related to Future Amortization:

- Earnings review – An earnings review is required prior to amortization, pursuant to ORS 757.259(5).
- Prudence Review – A prudence review is required prior to amortization and should include the verification of the accounting methodology used to determine the final amortization balance.
- Sharing – One hundred percent of the deferred balance is subject to utility recovery, pending a prudence review.
- Rate Spread/Design – The costs are allocated among all Multnomah County customers on an equal cents per kilowatt basis.
- Three Percent Test (ORS 757.259(6)) – The three percent test measures the annual overall average effect on customer rates resulting from deferral amortizations. The three percent test limits (exceptions at ORS 757.259(7) and (8)) the aggregated deferral amortizations during a 12-month period to no more than three percent of the utility's gross revenues for the preceding year.

<u>MMA Deferral Request</u>

PGE's MMA balancing account is a combination of an accrual and a balancing account wherein PGE develops a forecast of projected expenses over a five-year rolling period and establishes an accrual amount that levelizes those costs. Expenses, when incurred, are then booked to the MMA balancing account, offsetting the amounts collected under the annual accrual. This process is intended to result in an expected account balance of zero by the end of the five-year rolling period. In the next forecast of expected expenses, the current balance of the MMA balancing account is rolled forward within the balancing account and into the calculation of the proposed accrual.

As stated above, PGE already has a deferral underlying this account, which is docketed as UM 1915. PGE's initial request was approved by the Commission in Order 18-517, and PGE filed for reauthorization of this deferral on December 3, 2018. Staff does not believe that it is either more efficient or more transparent to defer MMA funds pursuant to this deferral, and therefore recommends that the Commission continue to review MMA deferral requests in docket UM 1915.

EE Customer Service Deferral Request

PGE established a balancing account to record the differences between the actual fully loaded qualifying expenses and the revenues collected under Schedule 110 adjusted for allowance for uncollectibles, franchise fees, and other revenue sensitive costs.

Proposed Accounting:
EE Customer Service accounting treatment: the balancing account is recorded in either FERC 182.3 (Regulatory Assets), when qualified expenses incurred exceed revenue collected from customers, or FERC Account 254 (Regulatory Liabilities) when qualified expenses incurred are less than revenue collected from customers. PGE amortizes the balancing account based on the rate collected from customers through Schedule 110, adjusted by revenue sensitive costs.

Estimated Deferrals in Authorization Period:
PGE did not provide an estimate of the amounts to be deferred.

Information Related to Future Amortization:

- Earnings review – An earnings review is required prior to amortization, pursuant to ORS 757.259(5).
- Prudence Review – A prudence review is required prior to amortization and should include the verification of the accounting methodology used to determine the final amortization balance.
- Sharing – One hundred percent of the deferred balance is subject to utility recovery, pending a prudence review.
- Rate Spread/Design – In accordance with current ratemaking treatment
- Three Percent Test (ORS 757.259(6)) – The three percent test measures the annual overall average effect on customer rates resulting from deferral amortizations. The three percent test limits (exceptions at ORS 757.259(7) and (8)) the aggregated deferral amortizations during a 12-month period to no more than three percent of the utility's gross revenues for the preceding year.

Residential Power Act Exchange Credit

With regard to the Company's deferred application request for a deferral for the RPA Credit, Staff had previously advised the utilities, including PGE, that a deferral is not required to support the RPA Credit balancing account. Language in the Northwest

Power Act requires that costs and benefits of purchase and exchange sales be passed through directly to each utility's residential load. Therefore, there is an independent statutory basis for the treatment of this item, which is an exception to the requirement that a deferral be filed.

PGE has stated that it would prefer the Commission to make this determination, and therefore did not withdraw this request from its Application.

Conclusion

With regard to the MCBIT accounts, the Company's application meets the requirements of ORS 757.259 and OAR 860-027-0300, but finds that the Company should update its deferral applications once estimates of deferred amounts are known. Staff received a verbal estimate from the Company, but requests that the Company provide written estimates in future deferral applications.

The EE Customer Service accounts require a deferral, but should be docketed separately for the reasons discussed above.

With regard to the other balancing accounts included in this application, Staff concludes that:

- The MMA accounts deferral is already provided for in Docket No. UM 1915, and the Company should file its reauthorization requests in this docket; and
- The RPA Credit accounts have an independent statutory basis in the Northwest Power Act for rate treatment, and therefore is an exception to the deferral requirement.

PROPOSED COMMISSION MOTION:

Approve Portland General Electric's (PGE or Company) request to authorize deferral of the variance between revenues and expenses associated with the Multnomah County Business Income Tax (MCBIT) for the 12-month period beginning December 7, 2018.

Approve PGE's request to authorize deferral of the variance between revenues and expenses associated with Energy Efficiency (EE) Customer Service for the 12-month period beginning December 7, 2018, and direct that this deferral be docketed separately (beginning with this deferral), and that subsequent requests for reauthorization be filed in the respective docket.

Deny PGE's request to defer Major Maintenance Accruals (MMAs) in this docket, as the Company already has a deferral application for these amounts which is docketed as OPUC Docket UM 1915.[3]

Deny PGE's request for a deferral of the RPA Credit, as a deferral is not necessary in order to facilitate the current ratemaking treatment for the balancing account already in place.

[3] OPUC Docket No. UM 1915 – the Commission approved PGE's Initial Deferral at the May 8, 2018 public meeting in Order No. 18-517.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 416

Revenue Requirement

PORTLAND GENERAL ELECTRIC COMPANY

Surrebuttal Testimony of

Greg Batzler
Jaki Ferchland

September 11, 2023

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 name is Jaki Ferchland. My position is Manager of Revenue Requirement, Regulatory Affairs.

Our qualifications were previously provided in our Direct Testimony PGE Exhibit 200.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to respond to the rebuttal testimony provided by the Public Utility Commission of Oregon (OPUC or Commission) Staff (Staff) and the Alliance of Western Energy Consumers (AWEC) (collectively, the Parties) with respect to PGE's 2024 test year revenue requirement.

Q. What specific issues do you address in your testimony and how is it organized?

A. We address the following issues:

- Section II – Flow Through vs. Normalized Taxes;
- Section III – Average Rate Base;
- Section IV – Fuel Stock; and
- Section V – World Trade Center Lease.

Q. Please summarize PGE's position regarding the above issues.

A. As the following testimony will demonstrate, parties offer proposals and adjustments that are unsupported, misguided, and based upon incorrect analysis. As such, we recommend the Commission reject the parties' proposals regarding the issues discussed here.

Q. Is there anything not addressed in testimony?

A. Yes. The parties reached a settlement in principle on the amount of uncollectibles and intend to submit a settlement agreement to the Commission in the near future, so we will not be addressing that issue in our testimony.

II. Flow Through vs. Normalized Taxes

Q. Please describe AWEC's proposed adjustment related to PGE's state-related Accumulated Deferred Income Taxes (ADIT).

A. AWEC continues to recommend that PGE change its accounting method for state income tax purposes from the current normalization method, which is required for federal income tax purposes, to the flow-through method.[1] The resulting impact from this change in method would reduce PGE's ADIT (thereby increasing rate base) and reduce tax expense.

Q. Have any other parties in this proceeding expressed an opinion on AWEC's proposal?

A. Yes. Staff does not support AWEC's proposal based primarily on the concern PGE raised in PGE Exhibit 1700 of intergenerational equity. Staff Exhibit 3000 states in part, "[a]ccelerating the distribution of customer accrued benefits ultimately is unfair to customers as current customers get the full tax benefit for long-lived assets that future customers will continue to pay for."[2]

Q. Does PGE agree with Staff's assessment?

A. Yes. This is one of many issues PGE raised in reply testimony regarding AWEC's proposal and we continue to agree. AWEC's proposal would provide a one-time benefit to current customers, while ensuring that, all else equal, future customers pay a higher cost.

[1] AWEC/600, Mullins/14.
[2] Staff/3000, Chipanera/5 at 17-19.

Q. Has AWEC offered any compelling new evidence in their final round of testimony to support their proposal or refute the above issue?

A. No. While AWEC asserts that the flow-through method does not result in large swings year to year, they have offered no evidence to demonstrate this, and the foundation of their proposal suggests otherwise.

Q. Please explain.

A. AWEC's proposed adjustment is predicated on a large swing in costs and benefits. That is, AWEC proposes a $74 million reduction in revenue requirement for two years, yet they say nothing to address the fact that, all else equal, customer's prices will clearly be $74 million greater in year three when the benefit is gone.

Q. Staff states that "if it is expected that the same amount would be flowed through to customers each year, then [they] could support [AWEC's] proposal."[3] Is there a method where such an expectation exists?

A. Yes. PGE's current method of normalization, which we demonstrated is the most common method for investor-owned utilities,[4] does precisely that. Customers receive a smoothed benefit that is normalized over the life of the asset.

Q. AWEC points to PGE highlighting the severe and negative cashflow impact as justification for their proposal. Does that make sense?

A. No. AWEC's argument here is effectively that if their proposal negatively impacts PGE shareholders, it must be good for customers. However, shareholder and customer interests are not misaligned as AWEC appears to believe. As we clearly demonstrated in PGE Exhibit

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[3] Staff/3000, Chipanera/6 at 1-2.
[4] *See* PGE/1704.

1700, AWEC's proposal would harm both customers and shareholders. Again, AWEC has provided no evidence or argument to actually refute the issues we raised.

Q. Did AWEC "demonstrate that the IRS normalization requirements do not apply to state taxes" [5] in their opening testimony?

A. No. While AWEC made a statement that there is no requirement to use a normalization method of accounting for state income taxes, they provided no evidence this is true.

Q. Does PGE have evidence to suggest that the State of Oregon does require utilities to follow Normalization Rules?

A. Yes. The State of Oregon has a "rolling" conformity[6] with respect to federal taxable income. In the latest legislative session, it was confirmed that Oregon conforms with the Internal Revenue Code (IRC) in effect on 12/31/2022.[7] IRC § 168 defines the allowed depreciation methods that may be used to calculate taxable income. IRC § 168(f)(2) states that public utility property may not be depreciated using any of the accelerated depreciation methods defined in IRC § 168 if the taxpayer does not use a normalization method of accounting. While Oregon has decoupled from some parts of the IRC, to our knowledge, Oregon does not currently decouple from any part of IRC § 168. Therefore, the normalization requirements *are* contained in Oregon law as well as federal law. As such, PGE believes that changing to a flow-through method of accounting for state income taxes would be a violation of Normalization Rules in Oregon.

Q. PGE provided a number of direct statements from both the Federal Energy Regulatory Commission (FERC) and the National Regulatory Research Institute (NRRI), that not

[5] AWEC/600, Mullins/14 at 8.
[6] Rolling conformity means that a state automatically conforms with all or certain provisions of the IRC.
[7] Or. Rev. Stat. § 317.010(7).

only opposed the flow-through method but summarized the faults of this method. How did AWEC respond?

A. AWEC did not respond to our direct quote from NRRI debunking their argument that customers do not receive the benefits of normalization. In response to the numerous justifications the FERC provides for why tax normalization is superior, AWEC's argument is effectively that the FERC regulates different aspects of a utility than state commissions without offering any evidence for why this should make any difference. AWEC also provided no response to those findings.

Q. What does PGE request of the Commission regarding AWEC's flow-through tax proposal?

A. Based on the clear evidence described above and within PGE Exhibit 1700 demonstrating the inaccuracies of AWEC's arguments, the harm of switching to the flow-through method, and the benefits afforded by PGE's current method of normalization, we request that the Commission affirm PGE's continued use of normalization for state income taxes and decline to adopt AWEC's flow-through proposal.

III. Average Rate Base

Q. Please restate Staff's argument and recommendation regarding PGE's method for determining rate base.

A. Staff continues to argue that PGE should not determine rate base using year-end point in time values but instead should use a method they propose and incorrectly term the "average of monthly averages" method. Specifically, Staff's method uses PGE's filed year-end (i.e., 12/31/2023) amount for net plant, which includes a full year of depreciation, and then effectively adds another half year of accumulated depreciation using PGE's total filed depreciation expense, which they state is an approximation of average accumulated reserve over the test period (i.e., 1/1/2024 through 12/31/2024). This proposed approach incorrectly utilizes misaligned periods (2023 vs. 2024) and methods (point-in-time vs. over time) that result in an inequitable and unbalanced view of PGE's rate base.

While PGE provided evidence to the contrary, Staff continues to state as support for their argument that this is the Commission's "favored method"[8] and disagrees with PGE's testimony demonstrating that Staff's method has never been used. Additionally, Staff argues their method is more accurate for capturing PGE's actual rate base over the test period and that PGE's year-end method, which is also used by other utilities in Oregon and is the most commonly used method in the state, effectively allows PGE to over-recover by roughly 36 basis points of its authorized return on equity (ROE).

[8] Staff/3200, Stevens-Young/5.

Q. Has Staff made any adjustments from their initial round of testimony?

A. Yes. Staff has revised the revenue requirement effect of their adjustment to be $15.7 million from $21.7 million in their opening testimony, though it is unclear in their testimony what led to this difference.

Q. Do any other parties support Staff's rate base arguments?

A. Yes. AWEC has also provided testimony that is supportive of Staff's proposal while recommending for the first time in rebuttal testimony an additional $11.6 million reduction to PGE's depreciation expense.[9]

Q. Was it appropriate for AWEC to recommend a new adjustment in its rebuttal testimony?

A. No. The Commission requires five rounds of testimony in general rate cases so that Staff and intervenors can identify disagreements with the Company's filing in their first round of testimony and then address the utility's detailed response in their second round of testimony.[10] Through this process, the issues become "more sharply focused" as the case progresses.[11] By identifying a new issue in rebuttal testimony, AWEC undermined the Commission's established process and the agreed-upon schedule. In addition, AWEC's timing provided PGE with limited time to respond and wholly deprived other parties of an opportunity to respond.

Q. Does Staff's proposed method actually derive an average rate base amount as it has been commonly used in Oregon in the past?

A. No. While Staff uses the term "average rate base," it is a misnomer, as we demonstrated in PGE Exhibit 1700. Staff is not calculating a 13-month average of 2024 rate base amounts

[9] AWEC/600, Mullins/2-6.
[10] *In the Matter of Avista Corp. Request for a Gen. Rate Revision*, Docket UG 288, Order No. 16-109 at 22 (Mar. 15, 2016).
[11] *See Id.*

because estimating monthly changes to rate base with no assumption of changes to capital amounts is not reflective of actual rate base over the test year. In fact, Staff's method does not accurately reflect PGE's rate base at any point in time. Staff's method artificially reduces PGE's total rate base to a level that is not reflective of PGE's past, current, or future rate base amounts and thus does not reasonably reflect the assets PGE has invested in to prudently serve customers.

Q. Please describe Staff's proposed method.

A. Staff's proposal isolates a specific component of PGE's net plant (i.e., the "net" or credit component) and carries that amount forward into the test year such that these credit amounts continue to accumulate. At the same time, Staff argues that continuing investments over the same period of time (i.e., the "plant" component of net plant) cannot and should not be carried forward. As a result, what Staff derives is not actually reflective of net plant nor is it an actual average of averages rate base amount.

Q. What is the impact of using Staff's proposed method?

A. Staff's method mismatches time periods and results in a non-sensical rate base amount that in no way reflects PGE's actual rate base. Specifically, Staff's method produces a rate base amount that will always be below what PGE currently reflects or is expected to reflect on its balance sheet. This ensures that, while customers will receive the benefits associated with PGE's investment in its system, they will not be fully paying the costs associated with this investment.

Q. Would it ever make sense for PGE or any other business to reflect its actual balance sheet amounts in the manner Staff proposes?

A. No. Reflecting financial statements in the manner Staff proposes would violate Generally Accepted Accounting Principles (GAAP). Specifically, Staff's method would violate the principle of periodicity and the principle of consistency. In short, GAAP is foundationally based upon ten key principles. The principle of periodicity establishes that accounting entries should be distributed across the appropriate periods of time. The principle of consistency ensures that consistent standards are followed in financial reporting from period to period to ensure financial comparability between periods. Staff's method neither matches the periods of time nor is it consistent with balance sheet reporting at either a point in time or over time.

Q. Does PGE reflect rate base within its results of operations reporting in the manner Staff proposes?

A. No. PGE's rate base is reflected consistently across time periods. That is, the time periods for gross plant, accumulated depreciation, and accumulated deferred income tax all match (as do the time periods for other rate base items).

Q. Is Staff's adjustment associated with any argument of imprudence related to PGE's invested capital?

A. No. Staff's recommendation and adjustment have no association with any prudence determination. If adopted, it would reduce PGE's prudent rate base amounts by $170 million without any claim or showing of imprudence.

Q. Is Staff's proposal a method that has ever been approved by the Commission or used by any regulated utility in Oregon?

A. No. Contrary to their claim and based on PGE's research, the methodology Staff is proposing has never been used by any utility in Oregon and is unlikely to have been used by any other state commission. When PGE requested that Staff provide evidence of their method having been in use, they were unable to provide a single example.[12]

Q. Does Staff acknowledge that the method they propose has never been used?

A. No. Even though Staff cannot provide any example of their specific method having been used, they continue to inaccurately represent that their method is the Commission's "favored" method. However, Staff now appears to concede that their proposal is not the traditional average of monthly averages approach by characterizing their method as "modified."[13]

Q. Has PGE demonstrated that the method used previously by both PGE and PacifiCorp is in fact not what Staff is proposing?

A. Yes. We have clearly and thoroughly demonstrated using the historical record that the average method used by Oregon utilities prior to the change to year-end also included average plant additions over the test period and that this approach was authorized through a Commission ruling made subsequent to every Commission order Staff cited in their opening testimony.[14] In contrast, Staff's proposal in this case would not include plant additions, resulting in an artificially reduced rate base. As the record on this was established in PGE Exhibit 1700 and Staff has made no attempt to respond to the facts presented, we will not repeat them here. However, we will highlight that, since Order No. 79-055 interpreted the term "presently in-

[12] Staff's response is provided as PGE Exhibit 3501.
[13] Staff/3200, Stevens-Young/5 at 8.
[14] PGE/1700, Batzler-Ferchland/13-21.

service" to mean that "[a] near future test period is clearly allowed,"[15] we are unaware of any subsequent Commission order interpreting this language differently. Thus, PGE believes that if an average of averages method were to be used, not only is it balanced and logical to follow the matching principle and include <u>all</u> components of net plant, including the 13-month average of plant additions over the test year, according to Order No. 79-055, it is allowable under the statute.

Q. Staff claims that PGE's current method for establishing rate base allows PGE to over-recover. Is their support for this claim convincing?

A. No. While Staff may accurately calculate an ROE basis point amount associated with their proposal, this calculation does nothing to prove PGE is over-recovering. In fact, because PGE's actual rate base is expected to grow larger (not smaller per Staff's methodology) post-2023, Staff's example provides an estimate of the additional basis point *deficit* PGE would face compared to our authorized ROE. That is, should Staff's mismatched proposal be adopted and using the numbers they provide, the Commission would be guaranteeing that PGE will underearn its authorized ROE by roughly 36 basis points due directly to this change in methods.

Q. Please explain why Staff's proposal will inhibit PGE's ability to earn its authorized ROE.

A. PGE has two relevant benchmarks for demonstrating that Staff's proposal will erode PGE's ability to earn its authorized ROE.

First, as we explained in PGE Exhibit 2800,[16] PGE has predominately under-earned its ROE over the last 20 years. In fact, as Table 1 of PGE Exhibit 2800 illustrates, PGE has under-

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[15] *In the Matter of Revised Tariff Schedules applicable to electric service in the State of Oregon, filed by Portland General Electric Company*, Docket UF 3443, Order No. 79-055 (Jan. 25, 1979) 9.
[16] PGE/2800, Sims-Outama/26 at Table 1.

earned its authorized ROE in 16 of the last 20 years, and none of the four years in which PGE over-earned its ROE occurred post-2015 when PGE changed rate base methodologies. As Table 1 below demonstrates, PGE has underearned in every rate case year by a significant amount (117 bps on average), since switching to the year-end rate base method. For comparison purposes, Table 1 also includes the four prior rate case years of 2007, 2009, 2011, and 2014, during which PGE forecast rate base using the average of averages method. As can be clearly seen, during those rate case years PGE both under and over-earned, whereas, since the change to year-end, PGE has persistently under-earned in every test year.

Table 1
Basis Point Impact of Authorized vs. Actual rate Base

Test Year	Rate Base Method	Regulated ROE	Authorized per Rate Case	Basis Point Difference
2007	Average	11.58%	10.10%	148
2009	Average	8.27%	10.00%	(173)
2011	Average	11.00%	10.00%	100
2014	Average	9.51%	9.75%	(24)
2007-2014 GRC Test Year Average				**13**
2015	Year-End	8.18%	9.68%	(150)
2016	Year-End	8.60%	9.60%	(100)
2018	Year-End	8.53%	9.50%	(97)
2019	Year-End	8.44%	9.50%	(106)
2022	Year-End	8.19%	9.50%	(131)
2015-2022 GRC Test Year Average				**(117)**

Second, PGE's method of calculating rate base is not causing it to over-earn. As there are many reasons other than the difference between PGE's authorized and actual rate base that could be causing this persistent under-earning, we isolate this specific component of PGE's cost structure. We partially addressed this in our reply testimony to Staff by providing a comparison of PGE's actual rate base amounts against forecasted amounts in each general rate case from 2014 through 2022. This analysis, which Staff did not address, was provided as PGE Exhibit 1702 and demonstrated that since PGE moved to the year-end method, approved rate base has been lower than the average rate base for the same year. The only exception to this was 2016; however, this can be explained by PGE's Carty plant, which did not come into customer prices, nor PGE's actual rate base, until midway through the year. After ratably adjusting for Carty, 2016's approved rate base is also lower than PGE's actual average regulated rate base.

Table 2 below illustrates and quantifies the impact of PGE's approved versus actual rate base. As can be seen below, of the 117 average basis point difference between PGE's authorized and actual ROE in Table 1 above, approximately three-quarters of the variance, or 76 basis points, is attributable to PGE's actual average rate base coming in greater than amounts approved. Additionally, for comparison purposes, we have included the calculated results for PGE's last rate case prior to the move to year-end rate base. As can be seen, there is a much smaller difference between approved and actual rate base amounts.

Table 2
Basis Point Impact of Authorized vs. Actual Rate Base

Test Year / ROO Year	Docket	Rate Base Method	Authorized Rate Base(4)	Actual Average Rate Base	Difference	ROE Basis Point Impact
2014	UE 262	Average	3,054,217	3,105,774	51,557	(26)
2015	UE 283	Year-End	3,785,421	4,009,617	224,196	(80)
2016	UE 294(1)	Year-End	4,143,584	4,268,624	125,040	(42)
2018	UE 319	Year-End	4,505,374	4,863,447	358,073	(105)
2019	UE 335	Year-End	4,744,710	4,949,366	204,656	(57)
2022	UE 394(2)(3)	Year-End	5,287,621	5,681,061	393,440	(97)
Average 2015-2022 bps impact:						**(76)**

(1) Ratably adjusted for the Carty Tracker
(2) Includes Colstrip
(3) Ratably adjusted for May 2022 price effective date
(4) PGE notes that, if using Staff's method, "authorized rate base" would be lower every year, resulting in a greater difference

Staff argues that PGE's method "over collects because rates are set based on a rate base value that is appreciably greater than the actual average rate base value during the test period."[17] As these results clearly demonstrate, PGE is neither over-earning in general nor are we over-earning as a result of our current method for calculating a test year rate base amount.

Q. Staff makes a point of stating that the "Test Year is intended to be representative of the Company's normal operations."[18] Does PGE agree?

A. We do, which is why we fundamentally disagree with Staff's proposal. As we demonstrate above, PGE is neither over-collecting broadly nor are we over-collecting on our test year rate base. In fact, the historical evidence provided above demonstrates the opposite. PGE's current method for establishing rate base already leads to a systematic under-collection, and if Staff's proposal is adopted, this persistent under-collection will grow larger. PGE should be afforded the *opportunity* to earn its authorized ROE. Adopting Staff's unbalanced method will make this exceedingly difficult.

Q. Is PGE's position that Staff's method mixes and matches year-end numbers with average numbers a "red herring" as Staff suggests?

A. No. PGE's statement that Staff is mixing and matching time periods is neither intended to mislead nor distract from the faults of Staff's proposal. Staff either fails to understand or refuses to recognize the point we are making. We are not arguing over the precision of Staff's numbers. We are arguing over the fundamental premise of Staff's proposal. The "mixing" and "matching" in Staff's proposal is both an issue of time periods (i.e., using a 2023 amount for capital additions versus a 2024 amount for accumulated depreciation) and of amounts at a "point in time" (i.e., December 31, 2023 for capital) versus amounts "over time" (i.e., January 1, 2024 through December 31, 2024 for accumulated depreciation). Not only are

[17] Staff/3200, Stevens-Young/8 at 14-16.
[18] *Id.*/5 at 20-21.

the methods misaligned, but the years are misaligned. The result reflects two mismatched periods that in no way are reflective of PGE's actual net plant balance at any time.

Q. Does Staff address the evidence that PGE presented regarding the fact that both PGE and PacifiCorp, Oregon's two largest utilities, have used the year-end method for approximately 10 years and that Staff clearly recognized this change in method when PGE employed it, and found it to be reasonable?

A. No.

Q. Staff notes in their testimony that Avista recently accepted a settlement proposal that is aligned with what Staff proposes for PGE. How do you respond?

A. Setting aside the fact that Avista's settlement has yet to be adopted by the Commission, we would note that Avista did not file *any* responsive testimony in UG 461. That is, Avista settled the entirety of their rate case without formally responding to any party testimony. Additionally, Avista reserved the right in a future proceeding to address the issue.

Q. What incentive might Avista have to simply settle this issue with Staff?

A. Avista's incentive may be one of efficiency. Avista serves utility customers in three states and Oregon comprises a very small share of Avista's total revenue base. According to their initial filing in UG 461, Avista's total Oregon revenue requirement requested was approximately \$84.7 million.[19] This amounts to approximately 6.5% of their total gas and electric retail revenues[20] and equates to approximately 3.2% of PGE's total requested revenue requirement in this proceeding. The impact to Avista from this change is likely immaterial to their overall operations, and thus it would appear that expediency took priority in adjudicating their Oregon

[19] *In the Matter of Avista Corporation, dba Avista Utilities, Request for a General Rate Revision*, Docket UG 461, Avista/501, Schultz/1.
[20] UG 461, Avista/100, Vermillion/3. Total gas and electric retail revenues of \$1,305 million.

general rate case request. Again, we would note that Avista reserved the right to address the methodology in the future, which shows that they were not necessarily agreeing to Staff's premise with their settlement.

Q. Did Avista include any 2024 test year capital amounts within their Oregon rate case filing?

A. Yes. Contrary to Staff's interpretation of ORS 757.355, Avista did include certain 2024 capital amounts within their 2024 test year request, which were ultimately included as part of their stipulated outcome.[21]

Q. Is there support for PGE's contention that Staff's proposed method will violate Normalization Rules?

A. Yes. 26 U.S.C. § 168(i)(9)(B) provides that the Normalization Rules are not satisfied if the taxpayer, for ratemaking purposes, uses a procedure or adjustment which uses an estimate or projection of tax expense, depreciation expense, or a reserve for deferred taxes unless such estimate or projection is also used with respect to the other two items and with respect to rate base. This prohibition is generally referred to as "the Consistency Rule." Using the misnamed "average-of-averages" method proposed by Staff will violate the consistency rule because Staff proposes to change rate base without changing the projection of tax expense, depreciation expense, and the reserve for deferred taxes. In other words, Staff proposes to change one of the four items that must be kept in sync without adjusting the other three.

Q. Are there any other Normalization Rules that would be violated with Staff's recommended change in rate base?

[21] See UG 461, Staff/200, Chipanera/7 at 17-19 and Second Settlement Stipulation, Table No. 3, part f.

A. Yes. Treasury Regulation 26 C.F.R. § 1.167(l)-1(h)(6)(i) makes it clear that the reserve excluded from rate base must be determined by reference to the same period as is used in determining ratemaking tax expense. Therefore, a taxpayer may use either historical data or projected data in calculating these two amounts, but they must be consistent. As explained in 26 C.F.R. § 1.167(l)- 1(a)(1), the rules provided in § 1.167(l)-1(h)(6)(i) are to ensure that the same time period is used to determine the deferred tax reserve amount resulting from the use of an accelerated method of depreciation for cost of service purposes and the reserve amount that may be excluded from the rate base or included in no-cost capital in determining such cost of services. The change proposed by Staff moves the calculation of rate base to a different period from the one used to calculate deferred taxes.

Q. AWEC claims that PGE's approach to year-end rate base "results in an inconsistent revenue requirement because it is capturing escalated expenses but not the corresponding accumulated depreciation in the Test Period."[22] Is their argument valid?

A. No. AWEC is fundamentally mixing concepts when PGE's test year is in fact entirely consistent. Specifically, for balance sheet items, which reflect point-in-time values, PGE has consistently forecast all of them at December 31, 2023, which is one day prior to PGE's price effective date and consistent with ORS 757.355. For income statement items, PGE reflects these amounts over time assuming a calendar year 2024 (i.e., PGE's forecast test year). There is no "corresponding accumulated depreciation" to PGE's 2024 test year expenses outside of depreciation expense, which we have already taken into account. AWEC's recommendation is based on a number of incorrect statements regarding how PGE calculates depreciation expense.

[22] AWEC/600, Mullins/3 at 18-20.

Q. How does AWEC claim that PGE calculates depreciation expense?

A. AWEC states that PGE's depreciation expense is "effectively calculated on a forward-looking basis over calendar year 2024."[23] However, this is incorrect as there are no 2024 plant amounts included within PGE's test year and thus no corresponding 2024 depreciation expense.

Q. AWEC describes PGE's method of annualizing depreciation amounts associated with new capital additions for 2023 to claim that PGE's approach is a mismatch of 2023 and 2024 depreciation expenses.[24] Is AWEC's understanding accurate?

A. No. AWEC's description excludes key details. Specifically, as we describe in PGE Exhibit 1700, new depreciation expense for 2023 is also assumed at a full year (i.e., annualized) for purposes of establishing accumulated depreciation in rate base. PGE Exhibit 200, Section III clearly describes how PGE's depreciation expense is both aligned with our requested rate base and PGE's 2024 test year for expense.

Q. Did Staff review PGE's depreciation expense?

A. Yes. Staff reviewed PGE's depreciation expense in detail and specifically discussed PGE's calculation and method for determining test year depreciation expense in Staff Exhibit 1700. After discussing their review of PGE's depreciation expense in detail over several pages, Staff ultimately states that "PGE complied with the Commission Order No. 21-463, and its calculated depreciation expense is reasonable."[25] Staff goes on to state that they "do not make an adjustment to PGE's depreciation expense in UE 416."[26]

Q. Has PGE forecast a rate base amount that assumes the average of averages methodology for gross plant, accumulated depreciation, and accumulated deferred income taxes,

[23] *Id.* 3 at 3-4.
[24] *Id.*/4.
[25] Staff 1700, Peng/10 at 19-20.
[26] *Id*. at 20-21.

similar to the methodology PGE and PacifiCorp used prior to moving to the current method?

A. Yes. PGE has recently conducted its capital budget process for 2024 and using these results, we have developed a preliminary forecast of total net plant (i.e., gross plant, net of accumulated depreciation and accumulated deferred income taxes) and depreciation expense, that is consistent with normalization requirements, using the average of averages methodology as allowed by Commission Order No. 79-055 and used by PGE and PacifiCorp prior to each utility's change to the year-end method.

Q. What is the result of this forecast?

A. This draft analysis using PGE's 2024 preliminary capital forecast results in an increase of $277.8 million to PGE's filed rate base amounts and a $4.5 million increase to PGE's filed depreciation expense. If PGE were to have filed its 2024 test year using the average rate base method historically employed by Oregon utilities following Order No. 79-055, our total revenue requirement request would have been approximately $30.5 million greater. Table 3 below provides these results.

Table 3
Year End vs. Average of Averages Results (millions)

	Year End Method (As Filed)	**2024 Average of Averages**	**Delta**
Gross Plant	12,249.5	12,650.0	400.4
Accum. Reserve	(5,441.3)	(5,552.1)	(110.8)
Accum. Def Tax	(667.3)	(676.6)	(9.4)
Net Utility Plant	**6,140.9**	**6,421.2**	**280.3**
Depr/Amort Exp.	**422.6**	**427.1**	**4.5**
Sales to Consumers	**1,004.9**	**1,035.4**	**30.5**

Q. Does this mean that PGE could have responded to OPUC Data Request No. 819?

A. No. PGE did not "refuse[] to respond" to this data request, as Staff states within their testimony.[27] In fact, as we clearly stated in our response to Staff, the request asked for "information that PGE has not prepared or forecast and that is not included within this proceeding." We continued by stating that "using an average of averages for 2024 accumulated depreciation and accumulated deferred income taxes (ADIT), requires a monthly forecast of plant closings from January 1 through December 31, 2024, which PGE has not yet developed as PGE has based its current request on plant closings as of December 31, 2023."[28] We did not provide the above information because, as we explained in our response to OPUC Data Request No. 819, we did not yet have a budget or forecast from which to calculate the requested information. In fact, this information only became available in draft form at the end of July, which is the normal time when preparing budgets for the following year. As such, PGE has now supplemented its response to OPUC Data Request No. 819, consistent with the information presented above in Table 3.

Q. Are there any other unintended consequences of making an abrupt shift to a new and not broadly used or supported methodology?

A. Yes. A change such as this, which is clearly non-representative of PGE's prudently invested capital, will likely signal to investors that PGE is a riskier investment relative to our peers. Utility investors favorably view regulatory jurisdictions that consistently apply ratemaking methodologies that enable a reasonable ability to earn near the allowed rate of return. Staff's proposal would be a change from methodologies applied in previous rate cases and erodes PGE's ability to earn at its authorized ROE. As such, the risks of investing in PGE will

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[27] Staff/3200, Stevens-Young/2.
[28] PGE's response is provided in full as Staff/802.

increase relative to our peers, while the rewards, particularly authorized ROE, will not, thus impacting investor decision-making. While this may not serve as reason alone for the Commission to reject this change, it should be considered that an unintended consequence of adopting this mis-matched method for a $170 million downward adjustment to rate base will likely be a negative investor reaction, impacting PGE's ability to effectively access capital markets and raise cost-effective capital.

Q. What does PGE request of the Commission?

A. We request the Commission recognize PGE's year-end method for establishing its test year net utility plant and depreciation amounts as reasonable and that the Commission decline to adopt Staff's or AWEC's proposals regarding this issue. ORS 756.040 provides that "[t]he commission shall balance the interests of the utility investor and the consumer in establishing fair and reasonable rates." And that "[r]ates are fair and reasonable […] if the rates provide adequate revenue both for operating expenses of the public utility or telecommunications utility and for capital costs of the utility." PGE has clearly demonstrated that adopting these proposals will result in rate base and depreciation amounts that are not reflective of the test year and are not fair and reasonable, which will lead to persistent and systematic under-earning, with the end result being that PGE will almost certainly under-recover its prudent investments used to serve customers.

IV. Fuel Stock

Q. Please summarize Staff's suggested treatment for PGE's fuel stock.

A. Staff continues to propose adjustments to PGE's gas, oil, and CO2 inventories. Their proposal has remained the same as first described within Staff Exhibit 2700. In short, Staff proposes adjustments to both the price and the quantity of PGE's fuel stocks and they continue to propose that PGE's CO2 allowance stock be fully removed. Additionally, Staff continues to claim that PGE's fuel stock balances are "mostly subject to and determined by financial considerations."[29]

Q. Did Staff respond to PGE's testimony demonstrating that our fuel stocks are both used and useful and valued correctly under the weighted average cost method?

A. Largely no. Staff chose to ignore a significant number of PGE's arguments while continuing to propose aggressive and unfounded reductions to both the quantity and price of PGE's fuel stock and while refusing to acknowledge the clear benefits customers receive from both a financial perspective, via PGE's annual net variable power cost filings, and a reliability perspective, with PGE's oil and certain gas reserves serving as low-cost insurance against emergency events such as pipeline disruptions, runaway prices, and market illiquidity.

Q. Did PGE characterize its fuel stock as having no financial aspect, or there being no financial consideration regarding fuel stock balances?

A. No. Contrary to Staff's mischaracterization of PGE's testimony, PGE made no such claim. What we did take issue with and clearly demonstrated within reply testimony was Staff's claim that financial considerations were the primary drivers of these balances. As we discussed in PGE Exhibit 1700 and will continue to demonstrate here, while PGE seeks to

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[29] Staff/4000, Ankum/3 at 19.

serve load as cost-effectively as possible, regardless of where those costs reside geographically, reliability is our first priority and both North Mist gas and Beaver oil serve as reliability insurance for PGE and customers.

Q. Staff uses MONET as an example of their concept of "constrained operations." Does MONET include the volume and value of gas in North Mist for use in PGE's power cost modeling?

A. Yes. As we state in PGE Exhibit 1700 and as quoted by Staff in their testimony, a secondary benefit to North Mist *is* the beneficial economics of injecting at North Mist during months when power prices are relatively lower and withdrawing to fuel plant generation during months when power prices are relatively higher, which PGE forecasts within its net variable power costs and provides to customers as a benefit.

Q. Does Staff recognize this customer benefit within their testimony?

A. No. While Staff devotes numerous pages to discussing financial optimization, beyond simply quoting our statement of fact, Staff ignores that this benefit is derived from the very gas they seek to remove from PGE's filing. The fact is, PGE manages its net variable power costs and its entire business of delivering safe, reliable, affordable, and clean energy in a least-cost, least-risk manner. Holding sufficient fuel reserves, while also optimizing these resources for customers is precisely what we do.

Q. What did this benefit amount to in PGE's 2023 net variable power cost forecast used to set customer prices?

A. The total benefit provided to customers from PGE's gas optimization model within MONET for 2023 was $11.8 million. That is, the forecast power costs used to set current customer prices are $11.8 million lower due to PGE's gas stock at North Mist. This compares to the total revenue requirement effect of PGE's gas stock in rate base of approximately $2.2 million.

Q. Is it reasonable to recommend a volume adjustment to North Mist gas, while at the same time customers receive a financial benefit for the same gas?

A. No. Staff appears to believe it is reasonable for PGE to provide customers the benefits of PGE's North Mist gas optimization, while at the same time arguing it is unreasonable for customers to incur the costs.

Q. Is there a distinction between "cushion" gas and PGE's contingency reserve gas?

A. Yes. Contrary to Staff's statements, there is a clear difference. According to the Energy Information Administration (EIA), cushion gas (or base gas) "is the volume of natural gas intended as *permanent inventory* [emphasis added] in a storage reservoir to maintain adequate pressure."[30] North Mist contains this cushion gas, however, as we have stated, it is not part of PGE's gas inventories and cannot be used by PGE. None of PGE's gas reserves are intended as permanent inventory. While it is true that, after a certain level of PGE gas withdrawal, the facility pressure will drop below what we would consider optimal, this gas is still available for use, should circumstances warrant the need. The fact remains that PGE's 1.2 BCF of contingency reserve gas can be and is intended for use during emergency situations, and contrary to claims from Staff, portions of PGE's 1.2 BCF have been used as recently as March of 2023, when PGE's inventory went down to approximately 1.0 BCF on an intra-month basis.

Q. Are there other occasions where PGE has withdrawn portions of its contingency reserve gas?

[30] "The Basics of Underground Natural Gas Storage," U.S. Energy Info. Admin. (Nov. 16, 2015) https://www.eia.gov/naturalgas/storage/basics/

A. Yes. PGE's gas inventory was below 1.2 BCF for multiple months in 2021, coinciding with the February 2021 ice storm declared emergency, with the March intra-month balance dipping below 0.8 BCF. In September 2019, PGE's gas inventory was also approximately 1.0 BCF on an intra-month basis. Considering that the first time North Mist even reached its full capacity was in July of 2019, a mere four years ago, we have utilized our reliability reserves somewhat regularly.

Q. Does PGE describe any of its fuel stock as fixed as Staff suggests in testimony?[31]

A. No. Nowhere on the page Staff cites, nor anywhere within Exhibit 1700, do we describe North Mist gas as fixed—because it is not.

Q. Is there accounting guidance on how to treat cushion gas versus working gas on a utility's balance sheet?

A. Yes. Which is precisely why the distinction is important. According to accounting guidance from PricewaterhouseCoopers (PwC), <u>only</u> cushion gas should be classified as part of property, plant, and equipment (i.e., at original cost). This is what Northwest Natural does for the cushion gas at North Mist, as they own North Mist and the cushion gas, which is not intended for sale. To record any of our 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. Staff also claims that PGE is "indifferent to carrying excess gas" and that "the financial incentives are for PGE to favor an excess of contingency gas." Is Staff's assertion accurate?

[31] Staff/4000, Ankum/9 at 17.

A. No. PGE has every incentive to carefully manage our gas reserves, as the price and quantity of gas injected into our leased storage must be expensed at the weighted average cost of gas (WACOG) as it is burned. Thus, when and how much PGE injects and withdraws gas is very important, as it ultimately impacts our total net variable power costs.

Q. Does the fact that PGE would lean on every tool necessary to ensure resource adequacy support Staff's position as they suggest?

A. No. While Staff recognizes that PGE has a responsibility as a provider of last resort, they do not appear to understand the true importance of that responsibility. The energy market does not have infinite depth and liquidity. 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 of the next marginal unit of gas or electricity being unavailable at any price. PGE is not 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. Does Staff accurately describe the weighted average cost (WAC) method or PGE's data response providing PGE's fuel inventory forecast?

A. No. While Staff gives the impression that they understand the data that has been provided to them, it is clear they do not. The "price" that Staff references in PGE's Data Request 639-A (and included as Figure 2 of Staff Exhibit 4000) is, in fact, not the weighted average price of PGE's gas. While the workbook Staff references and amounts Staff provides in Figure 2 of Staff Exhibit 4000 calculate a forecasted WACOG, the workbook does not provide a weighted average price over the period. As we explain in PGE Exhibit 1700, what is reflected in this workbook is the WACOG over the entire history of PGE's gas reserves at North Mist. This is performed by simply layering on the forecasted purchases and/or sales times the price of the purchase or sale onto the previous month's balance. Again, this does not reflect a WACOG over 15 months as Staff has suggested. Rather, it reflects a forecasted WACOG over the life of PGE's stored gas at North Mist.

Q. Staff argues that "WACOG is predicated on the notion that gas flows in and out of storage."[32] Do you agree?

A. We do and, in fact, that is exactly what occurs at North Mist. Fuel inventory is not akin to a wrench or transformer, which can be individually tagged and identified. 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 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 May of 2023, over 24.3 BCF have been injected into and over 20.3 BCF have been withdrawn from North Mist. That is approximately five to six times of PGE's total capacity over less than 5 years of North Mist being placed into service.

Q. How common is the WAC method for fuel commodities?

A. It is the predominant method for reflecting fuel commodity reserves precisely because each individual unit is indistinguishable from another.

Q. Is the original cost PGE paid for gas reserves at North Mist reflected in the WAC of its total gas reserves?

[32] Staff/4000, Ankum/10 at 8,

A. Yes. The WAC method accounts for every change in quantity and price since the inception of a particular inventory balance. As such, every weighted value at which PGE has injected and withdrawn its fuel stock is factored into the WAC of the total remaining balance.

Q. Are Staff's proposals regarding PGE's gas and oil reserves conflicting?

A. Yes. Staff's recommendation is opportunistically rationalizing different pricing depending on the commodity. On the one hand, Staff is arguing that a portion of PGE's gas be valued at original cost versus the industry standard of WAC because current gas prices are higher than historical prices. While, on the other hand, Staff is arguing that PGE's oil stock be valued at current market prices versus WAC because the current price of this commodity is lower than PGE's WAC. Using the industry standard of WAC avoids this type of gamesmanship.

Q. Did PGE testify that its oil stock is not for contingency events as Staff states?

A. No. PGE's oil stock has historically been retained for contingency events, leveraging Beaver's dual fuel capabilities, and this remains true. PGE does, however, recognize that this ultimately will change in future years, and we are upfront about working with Staff and stakeholders to develop an effective strategy to address this reality when the time comes. Disappointingly, rather than recognizing this and seeking to engage constructively on the issue, Staff chose to mischaracterize our statement.

Q. Would there be accounting implications from using different measurements of value both within and between PGE's fuel stocks?

A. Yes. GAAP requires consistency of inventory costing, and a company is required to use the same cost formula for all inventories having a similar nature and use. The fact is, all of PGE's fuel inventories are available for sale or use in operations, and the WAC method is PGE's chosen method of accounting.

Q. Staff continues to assert that PGE is over-earning on its fuel stock. Is this an accurate characterization?

A. No, there is simply no basis for Staff's claim. As we have demonstrated above and in PGE Exhibit 1700, all of PGE's gas and oil stock is available for use. PGE is not holding onto this stock in order to make money via a return on rate base. It is helpful to put these amounts in perspective with PGE's total annual net variable power costs (NVPC). The total amount of PGE's oil, gas, and CO2 allowance stock that is forecast within this proceeding is approximately \$34.5 million, which equates to approximately \$3.2 million of revenue requirement. Compare this to PGE's 2023 NVPC forecast of \$730.2 million, and PGE's actual 2022 NVPC of \$568.3 million, or 0.4% and 0.6% respectively. Additionally, PGE's most recent PCAM in 2022 was \$23.2 million above baseline power costs (i.e., forecast power costs used to set prices) and our 2021 PCAM was \$61.6 million above baseline power costs. If holding fuel reserves was based on the financial incentives of either earning a return on rate base versus the income statement benefit of reducing actual power costs expense, surely, PGE would have utilized more of our fuel stock during 2021 and 2022. However, while gas optimization served to reduce NVPC for both of these years, the primary function of this stock is to ensure reliability.

Q. Staff uses an insurance analogy when speaking about PGE's fuel reserves. How does PGE's oil stock and reliability reserve gas compare to PGE's insurance products for catastrophic events?

A. PGE's 2024 property insurance premium forecast in this proceeding totals approximately \$16.6 million, with per-event deductible amounts up to \$5.0 million for PGE's Main All-Risk coverage. Part of this coverage protects PGE property for events caused by fires, wind, ice, and earthquakes among other types of events. This coverage does not protect PGE from pipeline or other fuel disruptions, or runaway price excursions, which can quickly add up to many millions of dollars, while also putting PGE at risk of not being able to serve load. In contrast, PGE's oil reserves and reliability reserve gas total approximately $1.5 million in revenue requirement and could allow PGE to generate approximately 112,000 MWh[33] to serve load. While this can be compared to mitigating the risk of runaway market prices that reach or exceed $1000 per MWh, as we described in PGE Exhibit 1700, one must also consider the scenario in which the next marginal unit of energy is unavailable at any price.

So, while an insurance analogy may be appropriate, we would argue that our fuel reserves serve as a very cost-effective insurance product.

Q. Has the Northwest Pipeline, which serves gas to PGE's westside thermal plants, ever experienced a disruption?

A. Yes. Prior to North Mist being placed into service, the Westcoast Pipeline in British Columbia ruptured on October 9, 2018. This resulted in nearly all gas imported into the Pacific Northwest at Sumas being cut off, which impacted all natural gas-fueled generating facilities in the region, including PGE's. Directly following this incident, PGE took numerous actions, including:

1. PGE took Port Westward 1 and Port Westward 2 offline to provide relief to pipeline pressures;
2. Increased real-time market purchases;
3. Returned to service the 518 MW Boardman Coal Plant, which was offline prior to the rupture;

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[33] Estimated using Beaver unit generation of 750 dekatherms (Dth) for 70 MWh. 1,200,000 Dth/750 Dth * 70 MWh = 112,000 MWh.

4. Postponed Carty's planned outage to keep it running; and
5. Returned Beaver units that were in a planned outage to service early.

PGE was unable to utilize storage to maintain Port Westward 1 operations due to the limited storage levels experienced at the end of PGE's summer withdrawal operations. PGE strategically utilized Mist storage rights to fuel Port Westward 2 and Beaver during the Forced Majeure issued by regional pipeline operators.

Q. Does the fact that this emergency event occurred prior to North Mist being in service mean that PGE does not need these reliability reserves?

A. No. Fortunately, this emergency event occurred during a period of mild weather, which allowed the region to continue to serve electric load and heating demand. However, these types of events are unpredictable, and had this occurred just a few months later in February 2019, when Portland accumulated 6.5 inches of snow and a low temperature of 23 degrees Fahrenheit, the outcomes for the region and PGE's customers may have been more severe.[34]

Q. Have there been any other significant changes to PGE's resource stack since this event?

A. Yes. We no longer have Boardman in our fleet as the plant has been decommissioned. That means, all else equal, PGE would have needed to find an additional 518 MW of capacity in response to this event if it occurred today. Fueling resources from North Mist is now a critical tool in minimizing the impact of emergency events and it is a fuel source that would have allowed PGE to fill a large portion of the deficit that Boardman met during the 2018 event.

[34] The outcomes may have been more severe because during cold temperature events such as February 2019 electricity providers would have a high need for natural gas to fuel plants coinciding with a time where natural gas local distribution companies are serving high retail natural gas demand.

Q. Does PGE have an alternative proposal regarding its gas reserve balance?

A. Yes. Because MONET uses PGE's North Mist projected inventory balance and WACOG to forecast gas optimization benefits as we discuss above, we propose that the 2023 ending balance as provided in in PGE's final 2023 power cost forecast be used for determining PGE's gas balance. Doing so aligns PGE's December 2023 gas balance with the gas optimization benefits provided to customers as part of the 2023 Annual Update Tariff. The impact of this adjustment would reduce PGE's gas reserve balance from $23,862,415 to a total of $16,027,350; a reduction of $7,835,064 from PGE's filed fuel reserve balances.

Q. Did Staff respond to PGE's testimony regarding the customer benefit of holding CO2 allowances?

A. No. While PGE Exhibit 1700 provided a clear example of the financial benefit of purchasing CO2 allowances prior to the underlying obligation, Staff had no argument in response.

Q. Please summarize the relevant points regarding the need and prudency of PGE's fuel stock.

A. In summary, PGE's fuel stock amounts offer both financial and reliability benefits to customers and our valuation of these amounts is appropriate. More specifically, our testimony on the subject demonstrates the following:

1. The WAC method is the standard method for valuing fuel. PGE's WAC calculation does in fact account for the price paid and price sold for every molecule of PGE fuel. GAAP does not allow for the mixing and matching of methods.
2. All of PGE's fuel stock is available to serve customer load.

3. The amount included in customer prices for holding fuel reserves is an inexpensive form of insurance that mitigates the risk of a major or catastrophic event leading to a loss of load.
4. Beaver oil is still used and useful and PGE's current forecast balance is accurate and what we also expect to retain in 2024, barring an emergency event.
5. Customers have and will continue to benefit from the purchase of low-priced CO2 allowances.

Q. What do you request from the Commission?

A. We ask that the Commission affirm that PGE's gas, oil, and CO2 allowance balances are prudent and in service to customers, subject to an approximate $7.8 million downward adjustment to PGE's fuel stock balances included in the 2024 test year, to align PGE's gas reserves with the gas optimization benefits included in PGE's AUT. With this adjustment, PGE's forecast December 31, 2023, ending fuel stock balance totals $26.0 million.

V. World Trade Center Lease

Q. Does AWEC continue to propose a reduction to the rental expense associated with the World Trade Center Complex (WTC)?

A. Yes. AWEC continues to propose a $9.2 million reduction to this expense.

Q. Before addressing AWEC's arguments, please provide background on the WTC not previously provided in this case.

A. The WTC, originally named the Willamette Center, was built in 1978 as a part of a rejuvenation process initiated by the City of Portland in the 1970s. PGE purchased the land on which the WTC currently stands with the intention of building a corporate headquarters that would also house other businesses and contribute to the transformation of Portland's downtown waterfront area. The investment in the building, however, was scrutinized by the Oregon Commission and intervening parties at the time, resulting in the creation of 121 SW Salmon Street Corporation ("121 Salmon") and the transfer of the building to this non-utility subsidiary prior to completion. Upon completion of the complex, 121 Salmon entered into a sale and 65-year lease back agreement with a third-party purchaser-owner with 121 Salmon having the opportunity to repurchase the building at various trigger points, with the last being year 40 of the lease agreement. If 121 Salmon chose not to repurchase the building, it could still select to extend the terms of the lease agreement for three extension periods at a favorable reduced base rental rate, as shown in Table 4 below.

Q. How was the 65-year master lease agreement structured?

A. The master lease agreement between 121 Salmon and the third-party owner required lease payments for the entire complex to be made to the third-party owner. Then 121 Salmon entered into a sub-lease agreement for the entire complex with PGE's non-utility business unit, which then entered into sub-lease agreements with PGE's utility business and the other non-PGE occupants of the building. PGE's utility business was a rent-paying occupant whose base rent was equal to the price established in the master lease agreement multiplied by the percentage of the complex used (calculated by square feet). The non-utility occupants of the building were charged a base rental rate at the prevailing market value, and the difference resulted in a small amount of non-utility income. If the space could not be filled, this resulted in a non-utility loss.

Q. What does it mean that the purchase of the WTC was "encumbered" by the master lease agreement?

A. 121 Salmon was able to purchase the WTC at an amount set by the master lease agreement. It is unlikely that a third-party buyer would have been interested in paying a higher price for the WTC because of the locked-in significantly below-market base rental rate paid by 121 Salmon as set in the master lease agreement. The property was therefore considered "encumbered" by the lease for any other third-party buyer.

Q. Under the master lease agreement, what was the agreed-upon base rent?

A. Table 4 below shows the base rent payments included in the agreement for the initial lease term and each potential extension period.

Table 4
Base Rental Rates in WTC Master Lease Agreement

Initial Lease Term			Extension 1	Extension 2	Extension 3
1978-1979	1979-2004	2004-2018	2018-2028	2028-2038	2038-2043
$3.385 M	$5.137 M	$4.973 M	$2.487 M		

Q. Did the base rental payments by PGE change after 121 Salmon purchased the WTC in 2018?

A. No. These are the same amounts included in the current lease agreement between PGE and 121 Salmon.

Q. Is this the total rental expense that PGE has paid in each year as a tenant of the building?

A. No. As with all office space rentals, PGE's total rental expense also includes expenses for security, general maintenance, cleaning, administration, licenses and fees, utilities, property taxes, insurance, depreciation, and uncollectible accounts.

Q. Are these other expenses under dispute in this case?

A. No. The expense items are charged at cost. AWEC is disputing the base rent in this case.

Q. Describe how the structure of the lease agreement changed after the WTC was purchased by 121 Salmon in 2018.

A. Instead of maintaining a master lease agreement with a sub-lease arrangement through PGE non-utility, 121 Salmon entered into direct lease agreements with all tenants. The lease agreement between 121 Salmon and PGE maintained the same base rental rates as the original agreement. As shown and approved in Docket UI 405, for the PGE customer, there is no difference between ownership by a third-party affiliate or a non-affiliated third party.

Q. AWEC continues to dispute the base rent for the WTC in this case. What is AWEC proposing as an adjustment for WTC base rate rent charged to PGE?

A. AWEC is requesting a $9.2 million downward adjustment to PGE's annual WTC rental rate of $2.5 million. To support their proposal, AWEC has used a myriad of different arguments across two rate cases, with new arguments being introduced when prior arguments are shown to be unfounded by PGE. PGE has included its testimony from Docket No. UE 394 (UE 394) on this topic as PGE Exhibit 3505.

Q. In their most recent testimony, what does AWEC argue?

A. AWEC's primary arguments in rebuttal testimony are that:

1) The established rental rate does not meet the requirements of the lower of cost or market standard for affiliates.
2) Customers are the "anchor tenant" and "the ownership cost of the WTC has been in customer rates since docket UE 394."[35]
3) PGE "relied on the financial benefits its rental decisions have on the profitability of 121 SW Salmon to justify"[36] PGE's investment in the Integrated Operations Center (IOC).

Q. Before addressing each of these specific arguments, how does PGE respond to AWEC's proposal overall?

A. We continue to find AWEC's proposal highly inappropriate and unfounded. They have made numerous inaccurate statements regarding the comparison between the prior ownership and rental structure relative to the current ownership and rental structure that shows a lack of research, attention to detail and desire to understand their own proposal. Certain claims that they have made attack the integrity with which PGE has engaged in prior dockets (claiming PGE misrepresented information in UI 405)[37] and how 121 Salmon engaged in the purchase of the WTC (claiming "[t]he development of the IOC alleviate[d] the impairment of the below-market lease and allow[ed] PGE to outbid other potential market participants without

[35] AWEC/700, Kaufman/27 at 3-8.
[36] *Id.*/26 at 4-8.
[37] *In the Matter of Portland General Electric Company, Request for a General Rate Revision*, Docket No. UE 394, AWEC/100, Kaufman/30.

this knowledge").[38] In both instances, PGE provided evidence and analysis that AWEC's assertions were false,[39, 40] and AWEC did not continue to assert either idea after PGE provided its responsive testimony. Proposed reductions, such as this, should be made in good faith and with relevant facts; we find it concerning that that has not happened in this instance.

Q. Regarding AWEC's first argument, what is the lower of cost or market standard between the utility and affiliates?

A. The lower of cost or market standard provided by OAR 860-027-0048 simply states that goods and services provided by an affiliate or the non-utility operations of a regulated company should be transferred at the lower of the cost of providing the service or the prevailing market rate. Furthermore, it says that "[t]he nonregulated activity's cost shall be calculated using the energy utility's most recently authorized rate of return."

Q. What is PGE's most recently authorized rate of return?

A. In UE 394, PGE's mostly recent general rate case, PGE's authorized return on equity (ROE) was 9.5% and its authorized rate of return was 6.81%.

Q. What has been 121 Salmon's rate of return for the past three calendar years?

A. As provided in Exhibit 3506, 121 Salmon's rate of return was 3.43% in 2020, 1.77% in 2021, and 0.82% in 2022. The equity included in these calculations reflects the purchase price of the WTC by 121 Salmon, which was paid for by a cash infusion by PGE shareholders. As shown, none of these values come close to PGE's most recently authorized ROE of 9.50% or rate of return of 6.81% for its utility business.

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[38] AWEC/300, Kaufman/30.
[39] UE 394, PGE/1400, Tooman-Batzler/17-19.
[40] PGE/1700, Batzler-Ferchland/58.

Q. Was this information previously provided to AWEC? If so, what was their response?

A. Yes. These rates of return have been previously provided in PGE testimony both in UE 394 and in this docket regarding this issue. AWEC has not provided a direct response to these facts.

Q. What is the current market rate for base rent for office space in Portland?

A. As of Q2 2023, the comparable base rental rate for Portland was $32.23 per square foot.

Q. How does this compare to the base rental rate charged to PGE?

A. PGE is charged based on its proportionate usage of the WTC. Specifically, as reflected in Table 4 above, for the current lease term PGE pays $2,487,000 for the entire 500,000 square feet of space. This equates to a base rental rate of $4.97 per square foot, or approximately 85% below the prevailing market rate.

Q. Is AWEC aware that the rental rate charged to PGE is over 80% below the current market rate charged to other occupants of the WTC at the same time that the rate of return for 121 Salmon is currently less than 1%? If so, how have they addressed this point?

A. Yes, this information was provided in UE 394 and again in PGE Exhibit 1700 of this rate case. AWEC has not addressed this point.

Q. What, then, does AWEC use to argue for a base rental rate of *negative* $6.7 million?

A. AWEC's arguments rest on the notion that PGE's utility business has paid for ownership.[41] Further, they argue that the base rental rate should reflect right now the potential future value of the WTC in 25 years' time.

[41] AWEC/700, Kaufman/27 at 1-4.

Q. AWEC characterizes their value using multiple terms throughout their testimonies. They call it a terminal value, a transfer price, and a long-term cost of owning the WTC. What do these terms mean?

A. AWEC has failed to be clear about what this value truly represents. To be clear, this value is an attempt to calculate the gain 121 Salmon might experience if it were to sell the WTC – it is an assumption of the future value. They have claimed that our interpretation is incorrect, yet they repeatedly refer to it as a "transfer price," which, by definition, means the amount of money exchanged between the buyer and seller when a property changes ownership. It is the agreed-upon price that represents the value of a property being sold.

Q. AWEC states that PGE is incorrect in arguing that the transfer price is a sales price in 25 years' time and that their model "does not assume a sale of the property." How does PGE respond?

A. We find this logic to be even worse than if an actual sale was contemplated because it reveals that AWEC is not only arguing for non-utility money, but money that 121 Salmon does not have now and may never have.

Q. Have you disputed the calculation of this terminal value/transfer price?

A. We have not disputed the specific elements of the analysis because the premise has absolutely no foundation and is completely improper. AWEC's analysis is not conducted on rate-based assets that are actually owned by PGE customers (which does include other properties and buildings). Future potential gains of customer-owned property are not provided to customers within rates now, so why would it be appropriate to contemplate this here? A business's current "cost" is not based on a potential, unrealized value of property 25 years into the future. Again, AWEC is demanding money that 121 Salmon does not have and may never have.

Q. Do PGE customers own this asset?

A. No. Customer assets are paid for through rate base included in customer prices over the life of the asset. PGE customers have only ever paid rental expense for the WTC at a significantly reduced rate relative to market. The reasons customers do not own the WTC are provided at the beginning of this section and in more detail below.

Q. How does PGE respond to AWEC's argument that customers have paid for ownership because PGE is the "anchor tenant" of the WTC and that "the ownership cost of the WTC has been in customer rates since docket UE 394"[42]?

A. We find these statements to contradict AWEC's response to our data request sent on September 1, 2023.[43] The above statements appear to say that customers are essentially owners because they are the "anchor tenant" coupled with the (inaccurate) statement that ownership costs have been in customer prices since UE 394. However, in their response to our data request, AWEC claims they are not saying that customers are owners.

Q. So, first AWEC states in their rebuttal testimony that PGE's claim that customers have not paid for ownership of the WTC is incorrect[44] (implying to us that they believe customers to be owners), then they say customers are not owners, but then they say that customers deserve to be paid for the future potential equity of the building, yet 121 Salmon pays if the building is destroyed.[45] What does all of that mean?

A. PGE finds this contradictory string of arguments to be reflective a desire for all of the possible benefits of the ownership of an asset without having paid for it or bearing any of the associated risks.

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[42] AWEC/700, Kaufman/27 at 3-8.
[43] PGE Exhibit 3507 (AWEC Response to PGE Data Request No. 14).
[44] AWEC/700, Kaufman/27 at 1-3.
[45] PGE Exhibit 3507.

Q. How does PGE address AWEC's testimony that being an "anchor tenant" does mean that customers have paid for ownership?

A. Being a primary (or "anchor") tenant of an office space, building, or home has never translated to "ownership" in any business sector that we can find. This is because it is the owner who bears the risk associated with and provides the cash for the investment. That is true for the WTC. 121 Salmon is solely responsible for the occupancy risk associated with the building, and this is not a risk that has been or will be experienced by PGE customers. It was PGE shareholders who provided the cash equity to 121 Salmon to purchase the building.

Q. How does PGE respond to AWEC's claim that the cost of ownership is in customer prices?

A. The statement that the "ownership cost of the WTC has been in customer rates since docket UE 394"[46] is entirely false. The UE 394 general rate case included the same rental expense and costs for the WTC as every prior general rate case dating back to the inception of the lease agreement, and the included expenses are consistent with the terms of that lease agreement. To be clear, UE 394 included the same standard expenses for the WTC as it always has dating back to the late 1970s; it did not include any rate base or financing costs associated with the purchase of the WTC by 121 Salmon.

We further contend that it is illogical for any tenant to claim 100% ownership benefits (but no disadvantages) and a right to all of the future potential value of a building because that tenant is renting just over 50% of the space for a value that is 85% below the market rental rate. If AWEC's claim is based on the notion that rental payments should equate to ownership, shouldn't their analysis have at least prorated the value to correspond with the

[46] AWEC/700, Kaufman/27 at 3-4.

percentage of space rented? Shouldn't their analysis also contempt the 85% reduced rate relative to the market since not doing so would equate to double counting of the benefit? Their analysis does neither, but again, the premise of such an analysis has no merit so this is a moot point.

Q. What changed for PGE customers upon the purchase of the WTC by 121 Salmon?

A. Nothing. The rental rate remains the same, and the terms of the lease agreement remain the same as when the building was owned by Icahn Enterprise Holdings. Furthermore, any third party could own the building and the treatment would still be the same.

Q. AWEC states that "PGE also admits that PGE could have purchased 121 SW Salmon as a utility asset."[47] How do you respond?

A. While AWEC cites a data request for this response, we discussed this point in PGE Exhibit 1700 and PGE Exhibit 1400 of UE 394[48] so their characterization of an "admission" is a little confusing. To restate that explanation, PGE performed a high-level analysis to determine if ownership of the building by customers might be beneficial but ultimately concluded that it was not reasonable to attempt to add the WTC to rate base because of the additional risks that come with owning real estate, which are entirely unrelated to the utility industry or the service of providing electricity to our customers.

There was no obligation to perform this analysis; PGE chose to examine the possibility. Additionally, it is PGE's historical understanding that the Commission was not supportive of PGE's utility ownership of the real-estate asset at the time it was built, which is why the sale-leaseback agreement was initially established. We were able to confirm that there was

[47] AWEC/700, Kaufman/27 at 22-23.
[48] PGE Exhibit 3505.

criticism regarding the construction of the complex by the public while it was being built[49] and we confirmed that the original Commission order approving the sale-leaseback agreement in 1978 did not contemplate reacquisition of the building by PGE as a utility asset[50] – it only identified possible reacquisition by 121 Salmon, a non-utility business. While we do not believe the 1978 order prohibits PGE utility ownership, its substance was a contributing factor to our decision not to pursue PGE utility ownership of the WTC.

Ultimately, we did not believe it would be prudent for PGE to purchase the building, include it in current rate base, and have customers bear the various risks associated with the real-estate ownership of a city-center office building.

Q. Is it true that if PGE had pursued rate base treatment, PGE would be earning a 9.5% ROE from customers for the WTC instead of the 0.82% ROE that 121 Salmon is currently experiencing?

A. That is true.

Q. How do you respond to AWEC's claim that PGE "relied on the financial benefits its rental decisions have on the profitability of 121 SW Salmon to justify"[51] PGE's investment in the IOC?

A. PGE provided extensive testimony and documentation in UE 394 regarding the purpose and necessity of building the IOC. The driver for the IOC was the need for a space to house the foundational infrastructure needed to implement and operationalize the grid modernization initiative, a new data center, Integrated Security Operations Center (ISOC), integrated

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[49] *In the Matter of revised tariff schedules applicable to electric service in the State of Oregon,* UF 3157, Order No. 75-832 (Sept. 26, 1975) 32.

[50] *In the Matter of the Application of Portland General Electric Company for an Order authorizing it to execute a Sublease, guarantee lease payments… an affiliated interest*, Docket UF 3460, Order No. 78-646, (Sept. 6, 1978) 2.

[51] AWEC/700, Kaufman/26 at 4-6.

network operations center and a corporate emergency operations center, all of which could not be done within the WTC. Not only was there not enough space at the WTC but a seismic report showed that the WTC was not seismically sound. It would have cost approximately $304 million to upgrade only building 3 of WTC to address these seismic issues (which was about $95 million more than it would have cost to build the IOC.) Monetization of some additional square footage at the WTC was not a driving purpose for building the IOC–if this had been the case, it is unlikely PGE would have obtained full recovery of its investment in the IOC.

Q. AWEC references PGE's project justification form (PJF) for the IOC and highlights that a listed benefit of building the IOC is the ability to lease space at the WTC, which AWEC construes as a benefit for 121 Salmon's ownership. Is this an accurate reflection of what is provided in the PJF?

A. No. Once again, AWEC has failed to understand the master lease and sub-lease agreements in place prior to 121 Salmon's ownership. As explained above, prior to ownership of the WTC, 121 Salmon paid the full master lease payment to the third-party owner, but then 121 Salmon was responsible for occupying the building fully. Any space rented to a non-PGE tenant could be rented at fair-market value. This resulted in non-utility income. Conversely, space not rented resulted in non-utility loss. To be clear, PGE's utility business has only ever paid for its proportionate share of the rental rate on the WTC. This means that PGE non-utility paid a third party for the remainder of the WTC, and it became necessary to occupy the space to cover the rental expense made to the third party. As such, the statements made in the PJF were true regardless of 121 Salmon's ownership of the WTC.

Furthermore, the first statement in the PJF regarding the WTC, which comes at nearly the end of the document, is "[m]oving the operational departments out of the WTC frees up extra space that can be used for other PGE departments or sub-leased to outside clients. Sub-leasing would generate income to offset the master lease agreement."[52]

Q. What is the significance of the language used in the PJF?

A. It shows that AWEC's claim that ownership of 121 Salmon was used to make a financially driven decision regarding the IOC is false. The PJF refers to 121 Salmon's potential ability to "sub-lease" and it states that the income would "offset the master lease agreement." This is language reflective of a point in time when 121 Salmon did <u>not</u> own the WTC. 121 Salmon's ownership of the WTC ended the sub-lease arrangement. After the purchase, 121 Salmon only "leases" space at the WTC. And, under the ownership construct, there would be no reason to reference an "offset [to] the master lease agreement" because no such agreement exists under 121 Salmon ownership.

Q. What do you request of the Commission regarding AWEC's proposal to reduce PGE's base rent of $2.5 million by $9.2 million.

A. We request that the Commission reject this nonsensical proposal. AWEC has made a multitude of confusing arguments based on their own false statements and incorrect understanding of the relationship between these entities before and after ownership to demand that 121 Salmon should be *paying PGE* to rent the WTC.

A terminal value / transfer price is a future, unrealized value. It is inappropriate to claim that such a value should be provided to a renter at any the time, and it is certainly not something that can be provided 25 years in advance.

[52] Confidential AWEC/701, Kaufman/88.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

Exhibit	Description
3501	Staff response to PGE Data Request No. 064
3502	2014-2022 GRC Rate Base Basis Points
3503	2024 Preliminary Average Net Plant
3504C	2023 MONET Gas Optimization Balance
3505	Docket UE 394, Exhibit 1400 pages 16-27
3506C	121 Salmon ROE
3507	PGE Data Request No. 14 to AWEC

Date: August 30, 2023

TO:
JAKI FERCHLAND
PORTLAND GENERAL ELECTRIC
MANAGER, RATES & REGULATORY
121 SW SALMON ST, 3WTC-0306
PORTLAND OR 97204
pge.opuc.filings@pgn.com;

FROM: Bret Stevens
Senior Economist, OPUC
Robert Young
Managing Director of Economists.com of Portland LLC

OREGON PUBLIC UTILITY COMMISSION
Docket No. UE 416 - PGE Data Request filed August 22, 2023

PGE Data Request No 64

64. Reference Staff/3200, Stevens-Young/5, at lines 5 to 12:

    a. Staff disagrees with PGE's assertion that Staff's proposed method for determining test year rate base has never been used in Oregon, and they state that it is the Commission's preferred method. Please identify all prior general rate cases that have used the method Staff is proposing in UE 416. Please list the rate cases by docket number, test year, utility and order number for each instance when this exact method was used.

OPUC Response No 64:

In lines 5-8, Staff is discussing the use of the average-of-monthly averages method. The history of the Commission's use of, and PGE's move away from, this method was discussed at length in Staff/800.

Exhibit 3502 has been retained and transmitted in its native format

Information provided in electronic format only

Exhibit 3503 has been retained and transmitted in its native format

Information provided in electronic format only

Exhibit 3504C contains confidential information and is subject to

Modified General Protective Order 23-039.

Exhibit 3504C has been retained and transmitted in its native format

Information provided in electronic format only

V. World Trade Center Lease

Q. Does AWEC propose an adjustment regarding the World Trade Center (WTC) lease?

A. Yes. In his opening testimony, AWEC consultant Dr. Lance Kaufman argues that due to the purchase of the WTC Complex by PGE's non-utility subsidiary, 121 SW Salmon Corporation (121 Salmon), the rental rate charged to PGE for space in the WTC Complex should be recalculated to include an equity value based on a forecasted future sale price of the complex in 25 years' time, and that this value should be applied to the extent that 121 Salmon's return on investment is equal to PGE's cost of capital. This would ultimately result in a negative rental rate for PGE.[22]

AWEC also asserts that PGE's rental payments have increased since the purchase of the WTC Complex by 121 Salmon and suggests that PGE's representation that the annual lease expense would not change, as provided in Docket UI 405 approving the purchase transaction by 121 Salmon of the WTC Complex, was incorrect.[23]

Q. How do you respond to AWEC's proposal and statements?

A. We recommend that the Commission reject AWEC's proposed rental price change because it is highly inappropriate to ascribe a theoretical future equity value (from 25 years into the future) to current rental payments as though the unknown future value is owed to the renter. The testimony provided below explores the fallacies of such a recommendation. Additionally, PGE refutes AWEC's assertion that PGE misrepresented information provided in Docket UI 405 and will show that AWEC is wrong in making this claim.

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[22] AWEC/200, Kaufman/36-37.
[23] AWEC/200, Kaufman/30.

Q. First, is there anything you would like to add or correct regarding AWEC's consultant's characterization of the World Trade Center in his testimony?

A. Yes. Contrary to AWEC's explanation that the WTC Complex "only exists due to PGE"[24], the WTC, originally named the Willamette Center, was actually a part of a rejuvenation process initiated by the City of Portland in the 1970s. PGE purchased the property on which the WTC Complex currently stands with the intention of building a corporate headquarters that would also house other businesses and contribute to the transformation of Portland's downtown waterfront area. The investment in the building, however, was scrutinized by the Oregon Commission and intervening parties at the time, resulting in the creation of 121 Salmon and the transfer of the building to this non-utility subsidiary prior to completion. Upon completion of the complex, 121 Salmon entered into a 65-year lease agreement with a third-party purchaser-owner with the opportunity to repurchase the building at various trigger points, with the last being year 40 of the lease agreement.

A. Reporting of Total Lease Expense

Q. AWEC states that after 121 Salmon purchased the building in 2018 from its then owner, Icahn Holding Company, PGE's annual lease payments increased due in part to the new inclusion of depreciation in the cost.[25] Is this true?

A. No. While PGE understands AWEC's confusion due to the reporting change that occurred from 2017 to 2019 in PGE's annual Affiliate Interest Report (AIR) as a consequence of the sub-lease turning into a lease (resulting in a change in accounting), PGE has always paid for its portion of depreciation associated with the WTC Complex.

[24] AWEC/200, Kaufman/29
[25] AWEC/200, Kaufman/30.

Q. Could you explain further?

A. Yes. Prior to 121 Salmon's acquisition of the WTC Complex, there was a master sub-lease agreement in place between 121 Salmon and PGE. Under this construct, 121 Salmon billed PGE the entirety of the rental expense and PGE recorded it in a non-utility account. Operating expenses, property taxes and depreciation were also incurred in non-utility PGE accounts under this structure, and then an allocation process would charge PGE's utility business for its share of the rent, operating expense, property taxes and depreciation. The total cost to PGE's utility business under this method was shown in the annual AIR under the World Trade Center Facilities section of the Cost Allocation Manual, but the financial statements for 121 Salmon under this arrangement only showed the rental expense charged to PGE under the master sub-lease agreement.

After 121 Salmon purchased the WTC Complex in 2018, the sub-lease changed to a lease, and, as a result, the accounting entries changed. From that point forward, all operating expenses, property taxes and depreciation are incurred directly by 121 Salmon, which in turn bills PGE's utility operations for their share of the rent, operating expenses, property taxes and depreciation. As such, these amounts not only appear in the AIR report under the World Trade Center Facilities section of the Cost Allocation Manual, but they are included in 121 Salmon's income statement.

Q. What was the rental expense charged to PGE in 2017?

A. PGE was charged its proportionate share, based on square footage, of $4,973,000. This was consistent with the terms of the original lease agreement.

Q. What was the rental expense charged to PGE in 2019 and 2020?

A. PGE was charged its proportionate share, based on square footage, of $2,487,000 in both 2019 and 2020. This is also consistent with the terms of the original lease agreement.

Q. What was the total lease expense, inclusive of operating expense, depreciation, and property taxes, allocated to PGE in 2017?

A. The total lease expense allocated to PGE in 2017 was $10,157,042.[26]

Q. How does this compare to the total lease expense allocated to PGE in 2019 and 2020?

A. The totals allocated to PGE were $8,933,735 and $8,521,304 for 2019 and 2020, respectively.[27] [28]

Q. Do the amounts identified above suggest that PGE's representation in Docket UI 405 that the annual lease expense would not change is inaccurate, as suggested by AWEC?[29]

A. No. Consistent with PGE's application and documentation provided in Docket UI 405, the rental payment charged by 121 Salmon has remained consistent with the terms of the original lease agreement. Due to the reduced rental payments beginning at the end of 2018, PGE's total lease payments have actually been less since 2017.

B. Ownership of the WTC

Q. Was PGE ownership considered at the time of the 2018 purchase?

A. Yes. PGE performed a high-level analysis to determine if ownership of the building by customers might be beneficial, but ultimately concluded that it was not reasonable to attempt to add the WTC Complex to rate base.

Q. What factors were considered by PGE at the time of the purchase?

[26] Docket No. RE 64, PGE 2017 Affiliated Interest Report, Cost Allocation Manual p. 8.
[27] Docket No. RE 64, PGE 2019 Affiliated Interest Report, Cost Allocation Manual p. 7.
[28] Docket No. RE 64, PGE 2020 Affiliated Interest Report, Cost Allocation Manual p. 8.
[29] AWEC/200, Kaufman/30.

A. PGE considered that the WTC Complex as a business is unrelated to serving electric power to customers. This consideration was driven from our understanding that PGE did not currently own the building because stakeholders wished to exclude the cost of the construction of the complex from rate base when it was originally built.

PGE also considered that customers would not be interested in taking on commercial real estate risks associated with ownership of the building – specifically the risk of occupancy and the commercial lease market overall.

Q. Was there any obligation in a Commission order or in any contract associated with the WTC complex requiring PGE to first consider purchasing the building, and only if it was uneconomic, then the purchase could be made by its non-utility subsidiary, 121 Salmon?

A. No. We chose to perform an analysis to determine if it might make sense for PGE to purchase the building instead of 121 Salmon, however there was no obligation to do so, and it was our understanding that the historical position of the Commission was not supportive of PGE's ownership of the real-estate asset. In addition, we were able to confirm that there was criticism regarding the construction of the complex by the public while it was being built[30] and we confirmed that the original Commission order approving the sale-leaseback agreement in 1978 did not contemplate reacquisition of the building by PGE[31] – it only identified possible reacquisition by 121 Salmon. While we do not believe the 1978 order prohibits PGE ownership, its substance was a contributing factor to our decision not to pursue PGE ownership of the WTC Complex.

[30] Docket UF-3157, OPUC Order No. 75-832, p 32.
[31] Docket UF-3460, OPUC Order No. 78-646, p 2.

Ultimately, we did not believe it would be prudent for PGE to purchase the building, include it in current rate base, and have customers bear the various risks associated with the real-estate ownership of a city-center office building.

C. Lease Payments

Q. AWEC testimony states that "that goods and services provided by an affiliate or the non-utility operations of a regulated company should be transferred at the lower of the cost of providing the service or the prevailing market rate subject to the lower of cost or market."[32] Is this true?

A. Yes. Under OAR 860-027-0048, service provided by an affiliate to PGE must be provided at the lower of cost or market.

Q. Is there anything to add to AWEC's explanation of the function of lower of cost or market?

A. Yes. In addition to the section highlighted by AWEC, NARUC Guidelines state:

> The affiliate transactions pricing guidelines are based on two assumptions. First, affiliate transactions raise the concern of self-dealing where market forces do not necessarily drive prices. Second, utilities have a natural business incentive to shift costs from non-regulated competitive operations to regulated monopoly operations since recovery is more certain with captive ratepayers. Too much flexibility will lead to subsidization.[33]

Q. Is 121 Salmon providing a service to PGE where "market forces do not necessarily drive prices" resulting in self-dealing that could unfairly result in an overcharge to customers?

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[32] AWEC/200, Kaufman/27
[33] National Association of Regulatory Utility Commissioners, Guidelines for Cost Allocations and Affiliate Transactions, Exh. AWEC/202.

A. No. Market prices drive the rental rates for office space in downtown Portland. 121 Salmon uses comparable rental rate data from the area to determine rental rates for its non-utility tenants, while PGE is charged the amount from the original lease agreement set in 1978.

Q. Is 121 Salmon inappropriately shifting costs from its non-regulated competitive operation to PGE?

A. No. The rental rate charged to PGE is approximately 80% below the market rate charged to other non-utility tenants of the building, and PGE is only charged for its proportionate share of the use of the building as determined by square footage. Further, this share will decrease when PGE employees move to the IOC, which results in a decrease in WTC lease expense in the 2022 test year forecast as discussed in PGE Exhibits 400 and 800. Other costs associated with PGE's lease, consistent with the original lease agreement, are charged to PGE at cost. These charges are also consistent with comparable leases, where such costs are included in the operating expense portion of a tenant's rent.

Q. AWEC recommends "reducing the transfer price for the rent of the WTC to a level that sets the Affiliate's *expected* [emphasis added] return on investment to PGE's cost of capital."[34] What is meant by "expected?"

A. As shown in AWEC's analysis, "expected" means a theoretical amount 121 Salmon might be able to obtain from selling the WTC Complex in another 25 years' time when the current lease reaches its end.

Q. Why does AWEC select a point 25 years from now for calculating an "expected return on investment?"

[34] AWEC/200, Kaufman/26.

A. AWEC opportunistically selects a theoretical equity value from 25 years from now because that is the point when the value of the WTC Complex will no longer be encumbered by the current low-rate lease with PGE.

Q. Does this mean that the equity value of the WTC Complex right now continues to be encumbered by the low-rate lease with PGE?

A. Yes.

Q. Has 121 SW Salmon entered into any agreements to sell the WTC Complex in 25 years' time for a pre-determined price?

A. No.

Q. Is 121 Salmon required to sell the WTC Complex in 25 years' time?

A. No. There is nothing that requires 121 Salmon to sell the WTC Complex in 25 years.

Q. Is it known that 121 Salmon will sell the WTC Complex in 25 years' time?

A. No. This is a decision that would need to be analyzed approximately 25 years from now. Given the volatility of real-estate values that could occur over the next 25 years, it would not be prudent or reasonable for 121 Salmon to make such a determination at this time.

Q. Given that there is no meaningful evidence to support 121 Salmon's intention to sell the WTC Complex in 25 years' time (or at any other time), is it appropriate to use a theoretical, inflated equity value in a calculation of the cost of service to PGE?

A. No. It is not appropriate to set a transfer price for any goods or services based on an unknown future value that has not and may not ever be realized.

Q. What is 121 Salmon's current return on investment?

A. For 2020, 121 Salmon's return on equity was equal to 3.43%.[35] 121 Salmon does not currently hold any debt.

Q. Is 3.43% above PGE's authorized cost of capital?

A. No, it is below PGE's cost of capital of 6.81% and well below PGE's return on equity of 9.50%, as stipulated by Parties in this GRC.

Q. Does 121 Salmon intend to raise the rental rate to PGE in an effort to obtain a return equal to PGE's rate of return?

A. No. The rental rate will remain the same amount as originally established in the 1978 lease agreement and as recently approved by Commission Order No. 18-323 (Docket UI 405).

Q. What rental rates were established in the original lease agreement?

A. In 1978, 121 Salmon sold the building in a sale leaseback agreement to a third-party and the agreement guaranteed the rental rates as shown in Table 2, below. The below-market rates were established, in part, because 121 Salmon, not the owner, would be assuming the occupancy risk for the complex.

Table 2
Rental Payments in the Original
WTC Lease Agreement

Initial Lease Term			Extension 1	Extension 2	Extension 3
1978-1979	1979-2004	2004-2018	2018-2028	2028-2038	2038-2043
$3.385 M	$5.137 M	$4.973 M	$2.487 M		

Q. Were PGE customers exposed to occupancy risk during the 40-year period when the building was owned by a third-party?

A. No. The risk was entirely assumed by PGE's shareholders.

Q. Please describe 121 Salmon's recent challenges with occupancy risk, if any.

[35] See PGE confidential work paper "121 Salmon_ROE_2020_CONF".

A. Due to the COVID-19 pandemic and social unrest in the past couple of years, it has been more challenging to occupy all the space in the WTC Complex. Even now, more businesses are choosing to allow their employees to work from home reducing the need for office space, plus the WTC Complex is located next to the Federal Courthouse, which has been the epicenter of disturbances in downtown Portland over the past couple of years.

Q. Have PGE customers ever been exposed to the occupancy risk or other ownership risks associated with the WTC Complex?

A. No. 121 Salmon, and therefore PGE's shareholders, have always borne the risks associated with owning the building including the risk of leasing the space available to its full capacity.

Q. Have customers ever paid for ownership of the WTC complex through rate base?

A. No. The complex was sold to a third-party prior to opening in 1978 and was <u>never</u> included in PGE's rate base.

Q. In a standard real estate transaction, is there an obligation for the real-estate owner to provide a portion of equity to its renter? If no, why not?

A. No. Not only has the renter not paid for or taken on the risks associated with ownership, but equity value is extremely subjective and cannot be known until the property has been sold. As explained above, 121 Salmon does not even know if it will sell the building in 25 years let alone the amount that could be received.

Q. AWEC asserts that customers are entitled to a future potential equity value of the building because 121 Salmon purchased the building for a discounted amount due to the lease agreement encumbering the value of the complex. Is this appropriate?

A. No. A renter is not entitled to an assumed future equity value associated with ownership *because* they enjoyed and will continue to enjoy a discounted rental price for 65 years. The renter has and is already benefiting from the discounted rental price (as illustrated by 121 Salmon's current return). To use the benefit already being received as a reason to be entitled to additional benefits is illogical, especially when the renter has never been subject to the risks associated with ownership.

Q. Does AWEC's analysis include assumptions regarding the value of the below-market rental prices that have been charged to PGE for the past 40 years and the continuing below-market rental prices that will be charged for the next 25 years?

A. No. AWEC's analysis is flawed in that it does not include such assumptions. We do not correct these errors, however, because their entire analysis is fundamentally flawed in that it is based on the notion that current renters, who have never owned and have never shouldered any of the risks associated with ownership, are entitled to equity that cannot be realized for 25 years or more.

Q. If 121 Salmon had not purchased the building, would PGE be subject to a lower lease payment?

A. No. Ownership of the WTC Complex by an unaffiliated third-party versus ownership by an affiliated third-party does not and did not result in a more beneficial rental price to PGE. PGE and our customers continue to enjoy a lease rate well below market, consistent with the terms of the original lease agreement.

Q. What is your recommendation to the Commission regarding the adjustment proposed by AWEC for WTC lease expense?

A. We recommend the Commission reject AWEC's proposal. AWEC's attempt to seize a theoretical future equity value related to the WTC Complex is wholly inappropriate for multiple reasons.

First, ownership of the WTC Complex has never been paid for by customers through rate base or any other means. As a result, customers have never been exposed to the risks, particularly the occupancy risk, associated with owning real-estate. PGE's utility business, as a current renter of the WTC Complex, is not owed a future unknown equity value of this real estate asset.

Second, the equity value of the WTC Complex continues to be encumbered by the incredibly low rental rate enjoyed by PGE's utility business, there is no evidence of a sale in 25 years' time, and any applicable equity value would need to be known and realized for a return on investment to be calculated.

Lastly, PGE's utility operations have rented the building from third parties since 1978 at a reduced rate, and they are continuing to do so. 121 Salmon is also a third party that is maintaining the same below-market rental rate for PGE as would be enjoyed if any other third party owned the complex. Demanding additional value after benefiting from below market rates for 65 years, at the time when the affiliate is currently earning a return of less than half of the utility's authorized return on equity, is out of alignment with the rules and guidelines on affiliate transactions.

Exhibit 3506C contains confidential information and is subject to

Modified General Protective Order 23-039.

Exhibit 3506C has been retained and transmitted in its native format

Information provided in electronic format only

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September 8, 2023

Via Huddle

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Re: In the Matter of PORTLAND GENERAL ELECTRIC COMPANY,
Request for a General Rate Revision.
Docket No. UE 416

Dear Ms. Burton and Ms. Ferchland:

Please find enclosed the Alliance of Western Energy Consumers' Response to Portland General Electric Company's ("PGE") Ninth Set of Data Requests in the above-referenced docket.

If you have any questions, please do not hesitate to contact me.

Sincerely,

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

Enclosure

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 416

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Request for a General Rate Revision.	)))))))	ALLIANCE OF WESTERN ENERGY CONSUMERS' RESPONSE TO PGE'S NINTH SET OF DATA REQUESTS

Dated: September 8, 2023

The Alliance of Western Energy Consumers ("AWEC") Responds to PGE's Ninth Set of Data Requests as follows. Subject to the objections below, AWEC will provide responses and responsive documents to PGE's Ninth Set of Data Requests. Further, any future responses and responsive documents from AWEC will also be subject to the objections below.

GENERAL OBJECTIONS

1. AWEC objects to the instructions set forth in PGE's Data Requests to the extent that these instructions impose obligations on AWEC that exceed, are unauthorized by, or are inconsistent with the discovery rules.

2. AWEC objects to the request to the extent that the data requested is not relevant to the issues identified in this proceeding.

3. AWEC objects to the request to the extent that production of the data requested would be unduly burdensome and that the request is overly broad.

4. AWEC objects to the request to the extent that production of the requested data would reveal information protected by the attorney-client privilege, and/or the work product doctrine, and/or any other relevant privilege.

5. Each of the preceding general objections is incorporated by reference in each specific response below.

PGE DATA REQUEST NO. 14 TO AWEC:

In reference to AWEC/700, Kaufman/27 at 1-8, if Portland experienced a major earthquake and the WTC was destroyed, or if the retail-space in the bottom of the WTC flooded, is AWEC proposing that customers pay for any and all repairment costs to rebuild the WTC or reconstruct the non-utility retail space as “owners” of the WTC?

RESPONSE TO PGE DATA REQUEST NO. 14:

AWEC objects to the above request on the basis that it misrepresents Dr. Kaufman’s testimony. Without waiving this objection, AWEC responds as follows:

AWEC’s testimony does not state that customers are “owners” of the WTC, but that “the ownership cost of the WTC has been in customers’ rates since Docket No. UE 394” in the form of the rent PGE pays to 121 SW Salmon. If the WTC were to be destroyed, PGE would face the same risks as any other renter. AWEC’s cost model accounts for these risks.

Date: September 8, 2023
Respondent: Lance D. Kaufman

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 416

Transmission and Distribution (T&D)

PORTLAND GENERAL ELECTRIC COMPANY

Surrebuttal Testimony of

Kevin Putnam
Jaki Ferchland

September 11, 2023

Table of Contents

I. Introduction

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

A. My name is Kevin Putnam. I am the Senior Director Compliance & Utility Operations at PGE. My qualifications are provided in Reply Testimony, PGE Exhibit 2200 at 41.

My name is Jaki Ferchland. My position is Manager of Revenue Requirement, Regulatory Affairs. My qualifications are provided in Opening Testimony, PGE Exhibit 200 at 31.

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 Public Utility Commission of Oregon (OPUC or Commission) Staff (Staff) and the Alliance of Western Energy Consumers (AWEC) (collectively, Parties) with respect to PGE's Routine Vegetation Management (RVM) operations and management (O&M) expenses.

II. Routine Vegetation Management

Q. Please provide a summary of your testimony.

A. First, we explain why our initial RVM budget proposal is justified and why Staff and AWEC's proposed adjustments should be rejected. Second, we explain why Staff's RVM performance-based rate (PBR) mechanism should not be adopted. Finally, we explain why we support Staff's proposed RVM balancing account and how it satisfactorily addresses issues raised by both AWEC and Staff. It is also important to note that, the budget for RVM only includes work performed in non-High Fire Risk Zone areas. Compliance trimming that occurs in High Fire Risk Zones is included in the Advanced Wildfire Risk Reduction (AWRR) budget.

Q. What do you recommend of the Commission?

A. We recommend that the Commission accept Staff's proposed RVM balancing account and PGE's RVM budget proposal and reject Staff's proposed RVM PBR mechanism and RVM budget adjustments proposed by AWEC and Staff. The Commission should clearly document the amount of RVM included in base rates at **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** as requested in our opening testimony.

Q. Please summarize Parties' rebuttal testimony regarding PGE's RVM program.

A. Staff submitted rebuttal testimony that (1) reiterates support for their proposed managerial disallowance and (2) proposes revisions to their proposed RVM PBR mechanism. AWEC submitted rebuttal testimony that modifies its previous position to hold PGE's 2024 test year RVM budget flat at 2022 levels and instead proposes an "inflationary allowance of no more than 2 times the annual inflation rate," resulting in a proposed 2024 test year RVM budget of $32.5 million.[1]

[1] AWEC/600, Mullins/9 at 12-16.

A. Parties' Proposed Adjustments to RVM Test Year Forecast Should Be Rejected

Q. Please respond to AWEC's assertion that PGE "has an incentive to over-estimate baseline vegetation management costs"[2] because "it will not have to return this money to ratepayers if it underspends."[3]

A. The proposed RVM balancing account, supported by both PGE and Staff, negates AWEC's concern. Any incremental or decremental RVM expenditures compared to what is in base rates would be included in the balancing account and amortized to customers in the following year.

Q. Please respond to AWEC's proposal to provide an "inflationary allowance of no more than 2 times the annual inflation rate," resulting in a proposed 2024 test year RVM budget of $32.5 million.[4]

A. We disagree with this proposal. The record in this case clearly demonstrates why PGE's 2024 test year RVM cost of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** is justified and why applying an overall inflationary factor to the specific costs of RVM is not appropriate. In previous rounds of testimony and discovery (which we will not reiterate here), we have provided extensive information regarding the need to increase our RVM budget, which is driven by a very tight labor market for qualified line clearance tree trimmers.

Q. Please respond to AWEC's review of workpapers provided by PGE.

A. AWEC notes that the amount shown in the RVM workpaper is less than the amount requested in PGE's initial filing.[5] The reason for that is because the workpaper only shows the

[2] AWEC/600, Mullins/9 at 5-6.
[3] *Id*. at 7-8.
[4] *Id*. at 12-16.
[5] *Id*./8 at 16-17.

estimations for outside services, whereas the entire RVM budget also includes internal PGE labor.

AWEC also states that PGE provided no support for the assumed escalation rate of 16% shown in the workpaper.[6] We assume AWEC is referencing cell S5 of the workpaper.[7] Sixteen percent is a typographical error and should be 19%.[8] PGE has submitted a revised response with this correction. The formulas in the cost estimate cells accurately reference the assumed escalation rate of 19%. As shown in row 51 of the workpaper, the 19% estimated escalation rate is calculated as the average of the forecasted increase of labor and equipment costs from 2022 to 2024, as estimated by crew type.[9]

Q. In rebuttal testimony, does Staff respond to AWEC's proposal?

A. Yes. Staff asserts that they do "not agree with AWEC."[10] Staff recognizes that "the labor market for vegetation management service is tight – leading to increased costs."[11] Additionally, Staff observes that their "proposed balancing account will be able to capture any discrepancies in labor pricing" and that "any overspend in the budget will be subject to prudence review by Staff."[12] We agree with Staff's statements.

Q. Please summarize Staff's rebuttal testimony regarding the level of RVM costs.

A. Staff continues to support their recommendations made in opening testimony to (1) establish a balancing account and (2) reduce the amount of RVM costs by a managerial disallowance of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

[6] AWEC/600, Mullins/8 at 13-14.
[7] *See*, PGE Exhibit 3603 (Attachment A of PGE's revised response to OPUC Data Request No. 496).
[8] *See*, *Id*.
[9] *See*, *Id*.
[10] Staff/3300, Stevens/5 at 6.
[11] *Id*. at 7-8.
[12] *Id*. at 10-13.

Q. How do you respond to Staff's proposed RVM balancing account?

A. We continue to agree with Staff's proposed balancing account with clear documentation of the amount of RVM costs included in base rates of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[13] There would be no annual deferral filing with an earnings test associated with the RVM balancing account.

Q. What is the basis for Staff's proposed managerial disallowance?

A. Staff asserts that PGE management has not given sufficient attention to the increasingly tight labor market which is leading to increased RVM costs.[14]

Q. Do you agree with Staff's proposed managerial disallowance?

A. No. Staff's adjustment is not supported by the record. PGE management takes the labor market issues seriously and, where possible, is taking steps to influence the supply of qualified line clearance journeymen.

Q. What specific actions has PGE taken to increase the labor supply of qualified line clearance journeymen?

A. As described in our reply testimony, International Brotherhood of Electrical Workers (IBEW) Local 125 is responsible for recruiting and training enough apprentices to meet the local labor demands for qualified journeymen line clearance tree trimmers. We have encouraged both the union and our third-party vendor to increase recruitment and training of apprentices. Part of union member dues are used to support the recruitment of new apprentices; it is the role of the union to ensure sufficient recruitment to meet labor demands.

Nonetheless, both PGE and our vendor take actions to recruit new apprentices. For example, PGE has taken the following actions to support and grow the local labor supply:

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[13] Staff/3300, Stevens/5 at 14-19.
[14] *Id.*/16 at 2-8.

- Seasonally offer 10-hour, 4-day work weeks when there is sufficient daylight;
- Carefully managing the RVM budget to maintain steady year-round work for our tree trimmers, making an hourly position function more like a salaried, stable job;
- When possible, manage schedules to minimize travel time to work sites by assigning work closer to a tree trimmer's home or desired location;
- Participating in vendor-sponsored symposiums with neighboring utilities to promote a safe and stable labor force; and
- Partnering with municipalities and industry partners (such as the City of Portland, the Youth Conservation Crew, and Women in Trades) to host industry career fair events to promote work opportunities.

Q. Does Staff make any specific recommendations regarding actions that PGE could take to increase the labor supply?

A. Yes. Staff suggests that PGE coordinate with IBEW Local 125 to advertise the apprenticeship program at local college and high school job fairs and to focus its efforts in historically disadvantaged areas or through local community groups.[15]

Q. What is PGE's response to Staff's recommendations?

A. As described above, we do already work with IBEW Local 125, our vendor, neighboring utilities, and local municipalities to promote awareness of this job and recruit new apprentices. It is our understanding that IBEW Local 125 and the Northwest Line Journeyman Apprentice Training Committee are revamping their outreach efforts at local high schools and career fairs to further increase the pool of apprentices. Unfortunately, increasing the workforce of qualified

[15] Staff/3300, Stevens/16 at 11-14.

journeymen line clearance tree trimmers is not as simple as advertising the apprenticeship program.

Q. What are the challenges associated with increasing the workforce of qualified tree trimmers?

A. It takes approximately two to three years to complete the apprenticeship program and become a qualified journeymen line clearance tree trimmer. The apprenticeship program includes classroom hours and extensive on-the-job training. Power Line Clearance Tree Trimmer Apprentices represent a significant portion of PGE contractor employees. As such, PGE promotes, facilitates, and pays for apprentices on-the-job training. Work on primary overhead lines requires a minimum two-person crew, including at least one qualified journeyman. The second crew member is typically an apprentice but may be a journeyman. The type of work an apprentice can perform in the field is limited by their apprentice step level of training. For example, a second step apprentice is only allowed to trim trees outside of a ten-foot radius from primary voltage power lines. This provides the apprentice with a safe training environment to learn new tools and how to safely trim around energized power lines, although it does limit the type of work certain crews can perform.

On-the-job training is also an important component of the apprenticeship program; however, the use of apprentices adds logistical complexity and increases costs. For example, not being able to utilize multiple journeymen on one crew due to a tight labor market restricts the vendor's ability to organize and perform multiple work types (e.g., bucket work, climbing trees), as well as having the experience necessary to perform highly technical work in challenging environments.

In summary, even with sufficient recruitment, it takes at least two to three years for an apprentice to become a qualified journeymen line clearance tree trimmer.

Q. Are there other factors that impact the availability of IBEW Local 125 labor supply?

A. Yes. While PGE is striving to increase the local labor supply, there are certain limiting factors that we are unable to directly influence.

One of the most challenging aspects of the local labor supply is the unprecedented and rapid increase in demand due to the increased proliferation and severity of wildfires in the region. The 2020 Labor Day wildfires were historic in their severity and immediately accelerated the need for vegetation management to reduce the risk of wildfires in the region. Soon after, Senate Bill 762 was enacted which codified the regional urgency to take immediate action to mitigate the risk of future wildfires.

Practically overnight, PGE needed significantly higher levels of vegetation management to both remove trees damaged by the 2020 Labor Day wildfires (and other storms, such as the February 2021 severe wind and ice storms) and to take proactive actions to remove vegetation that could impact the system. This was in addition to our existing RVM program. PGE is not alone in experiencing a rapid and sudden need to increase vegetation management; many utilities across the West are in a similar situation.

This unprecedented need for rapid deployment of more vegetation management across the West created a labor market supply disruption for which we continue to experience the effects.

Q. Other than constricted labor supply and increasing costs of labor and equipment, are there other drivers that impact RVM costs?

A. Yes. We have described in detail the direct costs of labor and equipment (trucks, fuel, tools, etc.) required to safely perform RVM. However, several other variables (e.g., disparate jurisdictional requirements and varied and unpredictable growing conditions) impact the cost of RVM. These variables add logistical complexity in scheduling and completing RVM, which adds costs.

Q. Please discuss the challenges with varied trimming and tree removal requirements among jurisdictions.

A. Various government entities, including the Oregon Department of Transportation (ODOT), counties and municipalities, such as the cities of Portland, Lake Oswego, Salem, Tualatin, Beaverton, and West Linn, have their own distinct and varied requirements for tree pruning and removals. We are seeing an increase in specific and unique tree ordinances, which results in increased costs due to logistical complexities and scheduling delays, with differing and layered requirements among jurisdictions.

For example, some cities require a notice of tree removal to be posted and then a waiting period, ranging from several days to multiple months. The city of Portland requires an annual programmatic fee, plus a specific permit, including approval by the homeowner and the city, to remove a tree. There are moratoriums placed on pruning or removals of certain tree species and additional approvals required for historically significant trees. For example, the city of Portland places a moratorium on pruning elm trees between April 15 and October 15 each year, which layers on additional logistical and permitting requirements and for one of the fastest and largest tree species during the growing season.

Another challenge is that most cities require trees to be planted with new construction projects, but often do not restrict or enforce the *type* of tree planted, resulting in a situation where the developer may plant incompatible trees underneath power lines, leading to additional tree and power line conflicts and increasing PGE's tree trimming requirements.

This patchwork of varied tree trimming restrictions and requirements increase vegetation management costs. There are additional expenses from permitting fees and the extra time it takes to manage and meet the specific and varied requirements within each jurisdiction. The most direct way to mitigate these additional costs and complexities would be if the Commission could adopt a standard that preempts unnecessarily restrictive local ordinances, thereby enabling PGE to trim and remove vegetation to OPUC specifications.

Q. How does variability in weather and growing conditions affect PGE's RVM program?

A. 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, during extremely hot temperatures (e.g., over 100 degrees), power lines sag which impacts the proximity of vegetation. Depending on when OPUC Safety Staff conduct their audits, these circumstances could impact their observations of possible violations.

B. RVM PBR Mechanism Should Be Rejected; RVM Balancing Account Should Be Adopted

Q. Briefly summarize the RVM PBR mechanism proposed by Staff in opening testimony.

A. In opening testimony, Staff proposed an RVM PBR mechanism that would impose an earnings test on the first $6 million of incremental RVM expenditure beyond what is included in base rates.[16] The amount of prudently incurred costs subject to amortization would be adjusted based on the number of OPUC vegetation management violations.[17] Figure 1 shows Staff's proposed violation thresholds and penalty levels, which are the same as those agreed to by PacifiCorp and Staff in the First Stipulation in Docket No. UE 399.[18]

[16] Staff/2000, Stevens/24 at 4-18.
[17] *Id*. at 6-7.
[18] *Id*. at Table 3.

Figure 1.
Staff's RVM PBR Thresholds Proposed in Opening Testimony

Level	Threshold	Penalty
Level I	150	100 bps
Level II	225	150 bps
Level III	325	200 bps

Q. What changes did Staff make to their proposed RVM PBR mechanism in rebuttal testimony?

A. In rebuttal testimony, Staff proposes to modify the thresholds informed by PGE's "violation history"[19] instead of using PacifiCorp's thresholds (shown in Figure 1) and to provide an incentive of an increase of 100 basis points if fewer than 175 probable vegetation violations are found by OPUC Safety Staff.[20] The revised RVM PBR thresholds are shown in Figure 2.

Figure 2.
Staff's RVM PBR Thresholds Proposed in Rebuttal Testimony

Level	Threshold	Earnings Test
Level I	175<	+100 bps
Level II	260	+0 bps
Level III	345	-50 bps
>Level III	>345	-100 bps

Q. PGE opposed the RVM PBR mechanism proposed by Staff in their opening testimony.[21] In light of the changes to the RVM PBR mechanism proposed by Staff in rebuttal testimony, has PGE's position changed?

A. No. There are still multiple fundamental issues we have with Staff's proposed RVM PBR mechanism. First, while we are not lawyers, we understand that there is no legal basis for imposing an RVM PBR mechanism on PGE. We reserve our legal arguments for opening

[19] Staff/3300, Stevens/14 at 6.
[20] *Id*. at 4-7.
[21] PGE/2200, Bekkedahl-Putnam/2 at 8-9.

briefs. We are unaware of any instance wherein a PBR mechanism is imposed on a utility in Oregon without it being part of a settlement or otherwise agreed to by that utility. Our reply testimony describes examples wherein a utility has agreed to a PBR mechanism via settlement or other agreement, such as PacifiCorp's vegetation management PBR mechanism in Docket Nos. UE 374 and UE 399 and PGE's service quality metrics mechanism in Docket No. UM 814.[22]

Second, neither Staff's testimony nor their responses to discovery have demonstrated that OPUC Safety Staff's annual audit is conducted using a transparent, repeatable, and statistically valid methodology that is applied consistently year-to-year. However, Staff proposes to use the number of probable violations observed by Safety Staff to impact the amount of prudently incurred costs we can recover each year. It would be unreasonable to adopt a mechanism based on an underlying methodology that is not statistically sound and cannot be applied uniformly and consistently year-to-year.

Finally, the threshold levels proposed by Staff are incongruous with the level of PGE's historical number of probable violations and Staff's own observations about PGE's level of probable violations.

Q. Why is the methodology of the audit relevant to Staff's proposed RVM PBR mechanism?

A. Staff's proposed RVM PBR mechanism uses thresholds based on the number of probable vegetation violations cited by Safety Staff in their annual audit of PGE's system. The statistical validity and repeatability of the methodology employed by Safety Staff in their annual audits would affect the number of probable violations which would directly impact the amount of prudently incurred RVM funds recoverable by PGE.

[22] *See,* PGE/2200, Bekkedahl-Putnam/19 at 3-12.

Q. What type of methodology would you expect Safety Staff to employ when identifying and citing probable vegetation violations given that the number of those citations would have a direct financial impact on PGE?

A. We would expect Safety Staff to employ a transparent, consistent, and statistically valid methodology to audit PGE's system. The same methodology and metrics would be repeatable and used each year, thus enabling accurate year-to-year comparisons to determine whether PGE is trending positively or negatively.

Q. Based on the record developed in this proceeding, does Safety Staff use a statistically valid, repeatable, and transparent methodology with consistent metrics that enable accurate year-over-year comparisons?

A. No. In discovery, we asked Staff to provide all internal policies and procedures, guidelines, or checklists detailing the audit requirement and methodology to be followed by OPUC Safety Staff when performing audits to identify probable vegetation management violations, including the methodology by which Safety Staff selects which area(s) of PGE's system to audit at a given time. Staff provided no documentation of any internal policies and procedures, guidelines, or checklists detailing the audit requirement and methodology followed by Safety Staff.[23]

It does not appear that Safety Staff chooses which parts of PGE's system to audit based on a statistically valid random sample survey. Rather, "OPUC's vegetation audits consist of a target to spot check the entirety of the system, however, access limitations that could be the result of weather, fires, road construction or other unplanned events can limit access to a

[23] *See,* PGE/2201, Bekkedahl-Putnam/2 (OPUC Response to PGE Data Request No. 28).

particular area."[24] The record also shows that Safety Staff do not track the number of line-miles audited[25] or the number of hours spent auditing.[26]

Q. Staff contends that PGE "mischaracterize[d] OPUC's data request responses" regarding the rigor of OPUC Safety Staff's audit process and provided additional detail regarding its audit process in rebuttal testimony.[27] Did the additional detail provided by Staff address your concerns about the rigor and transparency of Safety Staff's auditing process?

A. No. Unfortunately, Staff only describes the documentation undertaken,[28] not the methodology employed to determine which parts of the system are audited to make sure they are a statistically representative sampling. Staff seems to assert that "its substantial history of audits" means there is rigor and consistency to Safety Staff's annual audits. We disagree. Just because numerous audits have occurred does not mean they were conducted via a transparent, documented, and statistically valid sampling methodology with consistently applied metrics. For example, if in one year, Safety Staff utilized a team of three to cover 500 line miles of PGE's system and then next year only an average of two team members were available to conduct the audits and could only cover 300 line miles, it is fair to conclude that more probable violations would be identified in the first year than the second. For such metrics to be used to determine cost recovery, there must be consistency from year-to-year for a valid comparison to be made. Importantly, even if OPUC Safety Staff were to adopt a statistically

[24] *See,* PGE/2201, Bekkedahl-Putnam/2 (OPUC Response to PGE Data Request No. 28).
[25] *See, Id.*/5 (OPUC Response to PGE Data Request No. 37).
[26] *See, Id.*/4 (OPUC Response to PGE Data Request No. 36).
[27] Staff/3300, Stevens/9 at 6-10.
[28] "Staff documents every observation of contact, provides photographic support, and […] has also included geolocation […]" (Staff/3300, Stevens/10 at 2-4). We do not question that Safety Staff provides documentation of its audit results. What we have not seen is evidence that Safety Staff employs a consistent and statistically valid sampling methodology to audit PGE's system.

valid, transparent and repeatable audit methodology with clearly defined and consistently applied metrics to provide year-over-year comparisons, it would need to be in effect for several years to establish a baseline against which to set any sort of thresholds.

Staff also says that PGE mischaracterized their data request response that says OPUC Safety Staff performs a "spot check" of PGE's system.[29] To be clear, the terms "spot check" and "spot checks" are used in Staff responses to PGE Data Request Nos. 28 and 37.[30] Staff says that the OPUC "evaluates the system-wide performance of PGE's vegetation program and, except for areas which may be inaccessible for a variety of reasons, completes a system-wide analysis of the program."[31] However, Staff provides no documentation that a statistically valid, random sampling methodology is used to ensure a system-wide analysis is achieved.

Q. Based on the number of probable vegetation violations cited by OPUC Safety Staff since 2007, please quantify the number of times PGE would have hit each proposed threshold.

A. The number of probable violations PGE has received in annual safety audits since 2007 is shown in PGE Exhibit 3601. Assuming Staff's proposed RVM PBR mechanism had been in place since 2007, Figure 3 shows how many audits would have been in each of Staff's proposed thresholds. Over 80% of PGE's audits would have fallen in the highest penalty threshold (Level IV) of greater than 345 violations, resulting in a penalty of -100 basis points.

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[29] Staff/3300, Stevens/10 at 4-6.

[30] *See,* PGE/2201, Bekkedahl-Putnam/1(OPUC Response to PGE Data Request No. 28) and *Id.*/5 (OPUC Response to PGE Data Request No. 37).

[31] Staff/3300, Stevens/10 at 6-8.

Figure 3.
Frequency of Historic Audits Occurring at Each Proposed Threshold

Probable Violations Threshold	Number of Occurrences from 2007 to 2022 Safety Audits
Level I: <175	2
Level II: 260	0
Level III: 345	1
Level IV: >345	13

Q. What concerns does Staff have regarding PGE's current and historic level of probable vegetation violations?

A. Staff has not indicated concern with PGE's number of probable violations. In fact, Staff is clear that a degradation in performance is *not* a prerequisite for a PBR mechanism, implying that Staff does *not* observe degradation.[32] Staff asserts that the PBR mechanism would "act as a quick and efficient way of incentivizing PGE to improve its performance *if it declines*."[33]

Staff also posits that the "definition of 'quality service' should be clearly defined."[34] It is unclear what "quality service" means to Staff, but there is nothing in Staff's testimony to suggest a concern with the current level of probable vegetation violations.

Q. In PGE's most recent annual audit, what does Safety Staff express regarding PGE's level of probable violations?

A. The most recent annual audit PGE received was on August 26, 2022. Safety Staff included favorable remarks regarding their findings, saying "Staff is optimistic regarding the trim cycle modification PGE has proposed and adopted which *should continue to improve* the vegetation management program."[35] The audit goes on to say: "The short-term data from Safety Staff

[32] Staff/3300, Stevens/6 at 16-22.
[33] Staff/2000, Stevens/25 at 9-11 [emphasis added].
[34] Staff/3300, Stevens/6 at 5-6.
[35] Staff/3302, "Remarks" section [emphasis added].

audits starting in 2020 indicates the number of tree and energized primary conductor contacts *continues to decrease."*[36]

Q. Is there alignment between 1) Staff's proposed thresholds and Staff's statements in testimony and 2) the level of PGE's historical probable violations?

A. No. Staff has proposed thresholds that PGE would have exceeded 13 out of the last 16 years of Safety audits. It is incongruous for Staff to propose thresholds that fail to reflect actual historical performance of PGE while at the same time expressing no concerns about the current level of PGE performance.

Q. To put Staff's RVM PBR proposal in perspective, please discuss the most recent OPUC Safety report.

A. The most recent OPUC Safety report, received on August 26, 2022, was based on OPUC Safety Staff annual review that "occurred primarily from July 26 to August 22, 2022."[37] Staff "observed **407** locations where evidence existed of contact between vegetation and primary electrical conductors. The identified locations resulted in conservatively over **609** primary conductor vegetation contacts."[38]

Q. The OPUC Safety report referenced two different numbers of contacts. Which would be used to determine the violations threshold?

A. In response to discovery, Staff clarified that the "value identified in the threshold related to each location where vegetation contact occur[r]ed," which would be 407 violations in 2022.

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[36] Staff/3302, "Remarks" section [emphasis added].
[37] Staff/3302.
[38] *Id*. [emphasis in original].

Q. What is the ratio of observed locations with probable vegetation violations compared to the number of locations observed during OPUC Safety Staff's audit?

A. We are unable to calculate the ratio of how many probable violations were observed by Safety Staff compared to the number of locations observed because the audit report does not state how many locations were audited, how many line miles were audited, the amount of time spent auditing, or any other metric we could use to calculate a ratio. Through discovery, we asked for the number of line-miles reviewed for probable violations. Staff responded simply with "OPUC Safety Staff target spot checks throughout the service territory."[39] When we requested the number of hours spent identifying probable violations, we learned that "OPUC Safety Staff doesn't record hours logged."[40]

Q. Are there any ratios you can calculate to provide context to the number of probable violations?

A. Yes. We can calculate the ratio of probable vegetation violations compared to the number of trees within our managed right-of-way (ROW). There are approximately 2.2 million trees in our ROW.[41] This means the 407 probable violations observed in 2022 represents approximately 0.0185% of the total number of trees in our ROW.

Q. Please provide similar context regarding Staff's proposed RVM PBR thresholds.

A. Staff's lowest threshold (<175) violations represents approximately 0.008% of the total number of trees in our system and Staff's highest threshold (>345 violations) represents about 0.016% of the total number of trees in our system.

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[39] *See,* PGE/2201, Bekkedahl-Putnam/5 (OPUC Response to PGE Data Request No. 37).
[40] *See*, *Id.*/4 (OPUC Response to PGE Data Request No. 36).
[41] *See*, https://portlandgeneral.com/media-gallery/vegetation-management

Q. Safety Staff's audits are based on the National Electrical Safety Code (NESC) and Oregon Administrative Rule (OAR) 860-024-0016.[42] What does the NESC Safety Code say about vegetation management?

A. The NESC Safety Code is prepared by the National Electric Safety Code Committee and is a practical standard of safe practices that can be adopted by utilities and regulators. According to the NESC Safety Code, vegetation management should be performed around overhead lines but notes that it is not practical to prevent all vegetation contacts.[43]

Q. What happens after PGE receives the audit report?

A. Given the lag between when the audit occurs and when the report is sent to PGE, we have typically already addressed between 10-20% of the identified probable violations. We then evaluate our existing schedules as some of the identified probable violations are located within our normal tree trimming schedules. Typically, about 60-70% of the probable violations are already on our regularly scheduled RVM trim schedule and will be addressed within the applicable OPUC deadlines. For the remaining probable violations, we divert crews from our normal schedule to address those specific probable violations. Finally, we submit formal documentation to Safety Staff confirming correction of any identified probable violations. Exhibit 3602 shows the documentation we provided in response to the 2022 audit.

Q. Does PGE remediate all identified probable violations within the stated timelines?

A. Yes. We comply with the OPUC Safety Staff audit report to submit documentation confirming correction within 30 days for readily climbable trees and hazardous trees and within six months for all others.

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[42] Staff/3302, Stevens/1 (PGE Audit Report E22-62).
[43] *See,* NESC 2023, Vegetation Management, Section 218.

Q. In rebuttal testimony, Staff "challenges PGE to explain why the concept of an RVM PBR mechanism is unfounded, given Staff's reasoning above;[44] and, if PGE takes issue with Staff's proposed thresholds, Staff requests PGE to propose its own so that reasonableness of PGE's thresholds can be assessed."[45] How do you respond?

A. PGE disputes Staff's characterization that we have not explained why we do not support an RVM PBR mechanism. As stated in our reply testimony and again in this surrebuttal, while we are not lawyers, it is our understanding that there is no legal basis for a RVM PBR and there is no precedent for such a mechanism to be imposed on a utility without it being part of a settlement or otherwise agreed to by the utility.

In addition, there is no evidence in the record that Safety Staff uses an audit methodology that is statistically valid, transparent, repeatable, and utilizes consistent metrics year-to-year. Discovery demonstrated that OPUC Safety Staff records neither the number of line-miles audited[46] nor the number of hours spent[47] by Safety Staff when identifying probable vegetation management violations. Without a consistent, transparent, and repeatable auditing and sampling methodology, there cannot be confidence in the rigor or uniformity of Safety audits year-to-year, which would then be used to impact the amount of prudently incurred costs we can recover that are necessary to perform this important work.

[44] Staff appears to be referencing their previous statement that "a PBR mechanism is appropriate for incentivizing quality service and clearly communicating standards" (Staff/3300, Stevens/7 at 17-18).
[45] Staff/3300, Stevens/8 at 1-5.
[46] *See,* PGE/2201, Bekkedahl-Putnam/5 (OPUC Response to PGE Data Request No. 37).
[47] *See*, *Id.*/4 (OPUC Response to PGE Data Request No. 36).

Q. Staff proposed the RVM PBR mechanism as a way to "increase PGE's accountability when it comes to RVM." Are there any options other than the RVM PBR mechanism to achieve this goal?

A. Yes. The RVM balancing account, proposed in Staff's opening testimony and supported in our reply testimony, would provide enhanced accountability and transparency regarding our RVM program. The RVM balancing account would function such that any incremental or decremental costs compared to PGE's RVM budget included in base rates (**[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in this case) would be amortized in the following year.[48] Any incremental costs would be subject to prudence review and any underspend compared to what was in base rates would be returned to customers. To be clear, Staff did not propose a deferral with an earnings test on these amounts, and we would not be supportive of the balancing account under those circumstances as we would perceive that as an effort to carve out otherwise base rate spending in an effort to limit utility earnings.

Q. How would the RVM balancing account meet Staff's goal of increasing PGE's accountability regarding RVM?

A. The RVM balancing account would require PGE to annually demonstrate prudence of any RVM funds spent beyond what is included in base rates. The amount included in base rates goes through a prudence review as part of a general rate case, meaning all RVM funds spent would be subject to prudence review by Staff and other intervenors. Any underspend compared to what was in base rates would be returned to customers. This would also allow the opportunity for PGE and Safety Staff to work together to improve transparency, consistency, and statistical validity in the annual Safety audits.

[48] The account would accrue interest at the Commission's Modified Blended Treasury Rate.

Q. Do you have any comments on Staff Exhibit 3301?

A. Yes. Staff Exhibit 3301 shows the number of PGE's historical probable vegetation violations against its proposed RVM PBR thresholds, as well as "RVM Actual Spend" and "$ in rates" based on data provided by PGE in response to an OPUC data request. PGE has since submitted a revised data request response to correct the information conveyed in Staff Exhibit 3301.[49] The revised response provides corrected "RVM Actual Spend." We also clarify that the data Staff describes as "$ in rates" is in fact only the initial amount of RVM forecasted costs included in PGE's opening testimony. Throughout a general rate case, there are changes to PGE's revenue requirement ultimately collected through approved customer prices. Therefore, the data Staff labeled as "$ in rates" should instead be labeled as "RVM test year forecast included in PGE's initial filing." PGE Exhibit 3601 provides the revised chart.

Q. Have any other intervenors submitted testimony regarding Staff's proposed RVM PBR mechanism?

A. No.

Q. Please summarize your response to Staff's proposed RVM PBR mechanism.

A. We support approval of the proposed RVM balancing account, without a PBR mechanism. Staff stated in opening testimony that "Staff's balancing account proposal is not dependent on the RVM PBR mechanism."[50] The RVM balancing account would provide transparency and accountability in PGE's RVM spending because all funds would be subject to prudence review, either through a general rate case when setting the test year budget or through the annual amortization and prudence review process. The balancing account is also responsive

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[49] *See,* PGE Exhibit 3604 (PGE's revised response to OPUC Data Request No. 499).
[50] Staff/2000, Stevens/23-24 at 23-1.

to both Staff's and AWEC's proposed adjustments because any RVM underspend compared to what was in base rates would be returned to customers.

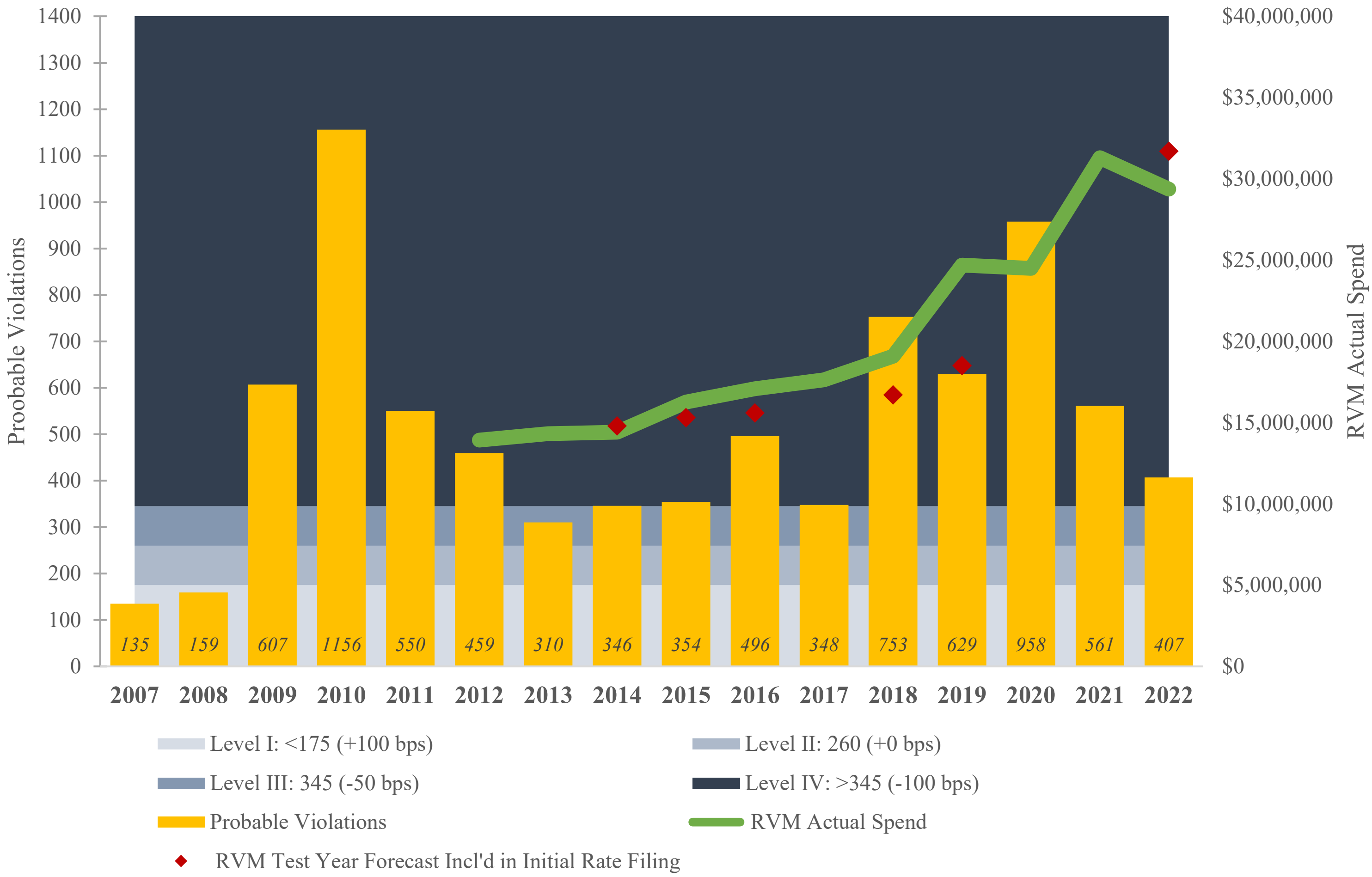
Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
3601	PGE's Historical Probable Vegetation Violations, Actual RVM Spend, and RVM Test Year Forecast Included in Initial Filing; Staff's Proposed RVM PBR Threshold
3602	Documentation that PGE Mitigated All Probable Violations Identified in 2022 OPUC Safety Staff Audit
3603C	PGE's Revised Response to OPUC Data Request No. 496 and Confidential Attachment 496-A_REVISED
3604	PGE's Revised Response to OPUC Data Request No. 499 and Attachment 499-A_REVISED

PGE's Historical Probable Vegetation Violations, Actual RVM Spend, and RVM Test Year Forecast Included in Initial Filing; Staff's Proposed RVM PBR Threshold



From:	Alex Konopka
To:	OPUC.NESCSafety@puc.oregon.gov
Cc:	Bradley Jenkins; Kevin Putnam
Subject:	E22-62: PGE Update
Date:	Friday, September 30, 2022 4:04:00 PM
Attachments:	image001.png E22-62R PGE Statewide Vegetation .docx

Good Afternoon OPUC Safety Staff,

As of 09/30/2022 (referencing attached E22-62R)

- 100% of the (19) Citation A vegetation locations have been successfully trimmed and cleared.
- 100% of the (23) Citation C vines have been successfully cleared.
- *I respectfully request that the OPUC Safety Staff update the enforcement log associated with E22-62 and successfully close those sections.*

PGE Vegetation Management is on schedule to complete the remainder of the Citation B and Citation D vegetation locations on-or-before February 27, 2023
A similar correspondence will be provided noting the successful completion of those sections.

Looking forward to the next quarterly meeting and the wrap-up of Wildfire Season!

Take care,

Alex Konopka
Senior Manager, Vegetation Management | 503-570-4406
portlandgeneral.com | Right Tree, Right Place
An Oregon kind of energy.

From:	Alex Konopka
To:	NESC.Safety@puc.oregon.gov; leon.grumbo@puc.oregon.gov
Cc:	Kevin Putnam; Bradley Jenkins
Subject:	2022 OPUC Vegetation Audit - Close Out
Date:	Monday, February 27, 2023 3:47:00 PM
Attachments:	E22-62L PGE Statewide Vegetation.docx image001.png

Good Afternoon OPUC Safety Staff,

As of 02/27/2023 (referencing attached E22-62L)

- All probable violations have been cleared in accordance with the 2022 OPUC Vegetation Audit results and subsequent deadlines for completion.
- *I respectfully request that the OPUC Safety Staff update the enforcement log associated with E22-62 and successfully close the 2022 Vegetation Audit.*

Thank you for your time and I look forward to seeing folks at the upcoming workshops.

Take care,

Alex Konopka
Senior Manager, Vegetation Management | 503-570-4406
portlandgeneral.com | Right Tree, Right Place
An Oregon kind of energy.

Exhibit 3603 contains confidential information and is subject to

Modified General Protective Order 23-039.

Exhibit 3603 – Attachment A contains confidential information and is subject to Modified General Protective Order 23-039.

Exhibit 3603 – Attachment A has been retained and transmitted in its native format

Information provided in electronic format only

September 11, 2023

To: Marc Hellman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE First Revised Response to OPUC Data Request 499
Dated April 6, 2023

Request:

Please provide an estimate of the actual cost of routine vegetation management and the amount in base rates for years 2007-2022.

Original Response (dated April 21, 2023):

PGE objects to this request on the basis that it unduly burdensome and requires significant new work. Without waiving its objection, PGE responds as follows

Attachment 499-A provides routine vegetation management actuals (unloaded) for 2012-2022.

In PGE's direct testimony in its last general rate case, Docket No. UE 394, the test year forecast included $31.7 million for routine vegetation management costs, excluding wildfire mitigation related vegetation management costs.

In PGE's direct testimony in Docket No. UE 335, the 2019 test year forecast included $18.5 million for vegetation management costs (unloaded).

In PGE's direct testimony in Docket No. UE 319, the 2018 test year forecast included $16.7 million for vegetation management costs (unloaded).

In PGE's direct testimony in Docket No. UE 294, the 2016 test year forecast included $15.6 million for vegetation management costs (unloaded).

In PGE's direct testimony in Docket No. UE 283, the 2015 test year forecast included $15.3 million for vegetation management costs (unloaded).

In PGE's direct testimony in Docket No. UE 262, the 2014 test year forecast included $14.8 million for vegetation management costs (unloaded).

Revised Response (dated August 29, 2023):

PGE objects to this request on the basis that it unduly burdensome and requires significant new work. Without waiving its objection, PGE responds as follows:

1. Attachment 499-A_REVISED provides routine vegetation management actuals (unloaded) for 2012-2022.
2. PGE cannot provide the historic amount of RVM in base rates because the specific RVM amounts have not been stated in the final orders or settlement documents. PGE can provide the amount of RVM costs included in the test year forecast used to develop PGE's initial proposal and included in PGE's direct testimony. Over the course of a general rate case, there are numerous discussions among parties and the final order by the Commission that change the overall revenue requirement. Therefore, the amounts shown below are only the amounts included in PGE's initial proposal based on the applicable test year forecast. They should not be interpreted as the final RVM amounts included in final rates.

    - In PGE's direct testimony in its last general rate case, Docket No. UE 394, the test year forecast included $31.7 million for routine vegetation management costs, excluding wildfire mitigation related vegetation management costs.

    - In PGE's direct testimony in Docket No. UE 335, the 2019 test year forecast included $18.5 million for vegetation management costs (unloaded).

    - In PGE's direct testimony in Docket No. UE 319, the 2018 test year forecast included $16.7 million for vegetation management costs (unloaded).

    - In PGE's direct testimony in Docket No. UE 294, the 2016 test year forecast included $15.6 million for vegetation management costs (unloaded).

    - In PGE's direct testimony in Docket No. UE 283, the 2015 test year forecast included $15.3 million for vegetation management costs (unloaded).

    - In PGE's direct testimony in Docket No. UE 262, the 2014 test year forecast included $14.8 million for vegetation management costs (unloaded).

Exhibit 3604 – Attachment A has been retained and transmitted in its native format

Information provided in electronic format only

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 416

Production

PORTLAND GENERAL ELECTRIC COMPANY

Surrebuttal Testimony of

Brian Clark
Stefan Cristea

September 11, 2023

Table of Contents

I. Introduction

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

A. My name is Brian Clark. I am the Senior Director of Thermal Generation and Planning at PGE. My qualifications appear at the end of this testimony.

My name is Stefan Cristea. I am a Regulatory Consultant in Regulatory Affairs. My qualifications appear at the end of Direct Testimony, PGE Exhibit 300.

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 Alliance of Western Energy Consumers (AWEC) with respect to PGE's 2024 test year production amounts.

Q. Are there any issues related to production that you will not address in this testimony?

A. In light of PGE's reply testimony, AWEC has dropped the issue of wind outside services, [1] so it will not be addressed here. We also are not addressing CUB's testimony on Biglow since we have reached an agreement in principle on that issue.

Q. How is the remainder of your testimony organized?

A. After this introduction, we have three sections:

- Section II: AWEC's Proposed Reduction to Generation Outside Services
- Section III: Qualifying Facility (QF) Pass-Through Mechanism
- Section IV: Qualifications

[1] AWEC/600, Mullins/14, at 2-4.

II. AWEC's Proposed Reduction to Generation Outside Services

Q. What is AWEC's updated proposal regarding generation outside services?

A. In rebuttal testimony, AWEC recommends "an adjustment for generation outside services, limiting the increase, at a maximum, to annual inflation rates."[2] This results in an updated reduction of $2,255,670 to this category of expense. AWEC reiterates that since PGE successfully operated its gas plants at high capacity factors during 2022, the 2024 costs should remain largely the same, despite the fact that elevated capacity factors are forecast to persist through 2024. In short, AWEC argues that PGE's generation outside services forecast should effectively remain flat with 2022 actuals, with a small increase to account for inflation.

Q. Does PGE agree with AWEC's proposal?

A. No. PGE disagrees with AWEC's arguments and updated proposal.

Q. Does PGE find it appropriate to focus solely on one cost element?

A. Yes, but only with proper context. Cherry-picking a cost element like generation outside services which has a high yearly percentage increase from 2022 to 2024 and then broadly stating that it is apparent that PGE is not making a concerted effort to control its costs is misleading without also acknowledging the wider trend of non-labor operations and maintenance (O&M) costs.[3] PGE's reply testimony articulates that non-labor O&M costs—excluding information technology (IT) and major maintenance accrual (MMA) costs as AWEC has also done here—are only increasing by 6.2% annually.[4] While some cost elements like "outside services" are increasing, other cost elements like "other outside services" and

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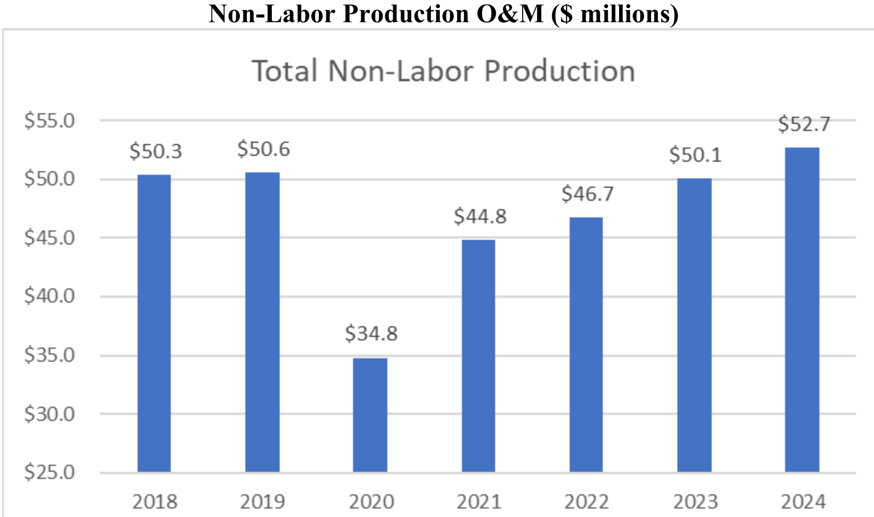
[2] AWEC/600, Mullins/2, at 8-10.
[3] *See* AWEC/200, Mullins/13, at 1-2.
[4] PGE/2000, Loos – Cristea/8, at 8-9.

"freight/transportation svcs" are decreasing. Accordingly, total non-labor O&M is not increasing by nearly the same percentage as the individual cost element of outside services.

Q. What is PGE's response to AWEC's statement that "it is common ratemaking practice to rely on actual cost data for the purposes of setting revenue requirement?"[5]

A. Actual cost data is precisely what PGE highlighted in PGE Exhibit 2000, Figure 1, which illustrated that PGE's total non-labor O&M forecast is strongly in line with historical actuals. While AWEC asserts that PGE has no evidence of needing a budget increase outside of its previous budgets,[6] PGE has already provided evidence to the contrary. In PGE Exhibit 2000, we discussed the significant impacts that the COVID-19 pandemic had on PGE's generation O&M costs in response to Staff's proposed reduction to generation O&M. The impacts of the pandemic can be seen in Table 1 below. Specific to outside services, the COVID-19 pandemic drove PGE's costs to a 10-year low of approximately $3.1 million in 2020—an unsustainable low that PGE is still recovering from.[7]

Table 1[8]
Non-Labor Production O&M ($ millions)



[5] AWEC/600, Mullins/11, at 1-9.
[6] *Id*.
[7] *See* PGE/3701, tab "Outside Services Costs," cell range B2:L15.
[8] *See* PGE/3701, tab "Total Production"

Q. AWEC wants "actual evidence demonstrating an increase in Generation Outside Services costs."[9] Is PGE's current budget consistent with actual cost data for 2023?

A. Yes. As provided in PGE Exhibit 3701, PGE has spent approximately $5.9 million through August 2023 on generation outside services as defined by AWEC,[10] which has already surpassed PGE's 2022 full-year actual spend of approximately $5.1 million.[11] Additionally, our year-to-date generation outside services spending is on target with year-to-date budgeted amounts (actuals of $5.9 million vs. budget of $5.8 million).[12]

Q. How does PGE's 2024 test year forecast of generation outside services costs compare to 2023 budgeted amounts?

A. Specific to the outside services AWEC has identified in their testimony (i.e., thermal and solar outside services costs), PGE's 2024 forecast is only 3.8% above amounts budgeted for 2023. Thus, as this *evidence* suggests, we expect to spend close to, or slightly above, amounts budgeted for 2023 and as the current demands on PGE's thermal fleet are expected to continue into 2024, our costs for 2024 are likely to be in line with 2023 amounts.

Q. Does PGE agree with AWEC's continued insistence that PGE's budget is supported by nothing other than previous budgets?[13]

A. We do not. PGE Exhibit 2000 provided a detailed account of PGE's budgeting process, which includes updates to budgets for known and measurable changes reflecting actual activities.[14] In their testimony, AWEC argues that PGE is "effectively shifting the burden to demonstrate the reasonableness of these costs to AWEC" by supporting our increase to outside services in

[9] AWEC/600, Mullins/11 at 1-9.
[10] PGE/3701, tab "2023 August Actuals," cell B13
[11] PGE/3701, tab "Outside Services Costs," cell J15.
[12] *Id*. cell D13.
[13] *See* AWEC/600, Mullins/11 at 1-9.
[14] PGE/2000, Loos – Cristea/4-7.

2023 and 2024 using budget information.[15] However, this is incorrect and misleading. AWEC directly asked for specific vendor information for every outside services increase at Beaver, Port Westward I, Coyote Springs, and the Kelso-Beaver (KB) Pipeline, which PGE provided in discovery and again as PGE Exhibits 2002 and 2003.[16]

Q. Does PGE agree with AWEC's point that sustained high-capacity factors should not be reason for increase?

A. No, PGE does not agree. A sustained high-capacity factor does lead to increased maintenance expense. As run hours continue to accumulate, more aspects of the plant need maintenance and at a quicker pace. A simple analogy is general car maintenance expense. One might drive their car more miles than normal over the period of one year, which will lead to a greater frequency of oil changes and other routine expenses. However, if this trend continues, there will be more and more routine maintenance expenses that occur at increasingly shorter intervals. Thus, not only are the oil changes more frequent in the second year but this is also true for the transmission fluid changes, the tire replacements, brake replacements, timing belt replacements, etc. It becomes easy to see how there can be a growing list of routine services over different intervals that begin occurring more and more frequently.

Q. AWEC also continues to assert that maintenance associated with increased capacity factors is typically covered under long-term service agreements (LTSAs) and thus is not a driver of routine maintenance.[17] How does PGE respond?

A. We disagree with this generalized statement. LTSAs do not and are not expected to cover every maintenance expense. More importantly, the biggest driver of this increase is PGE's

[15] AWEC/600, Mullins/11 at 4-5.
[16] *See* PGE/2002 and PGE/2003C.
[17] *See* AWEC/600, Mullins/10 at 20-21.

Beaver plant, which does not currently have an LTSA due to the age of its non-modernized turbines. This means that consistently elevated capacity factors, like the ones present at Beaver, can and do contribute to an increase in maintenance expenses that are not covered under an LTSA and are paid for by the increase in outside services.

Q. Did Staff have a similar adjustment in their opening round of testimony?

A. Yes. Staff proposed a reduction for the total generation non-labor O&M forecast in Staff/1300, premised on reducing the forecast closer to 2020-2022 actuals.

Q. Please describe the resolution of that issue.

A. PGE filed reply testimony that pointed to 2019 actuals being closely in line with the 2024 forecast for all of non-labor O&M.[18] The analysis PGE submitted showed that from 2019 to 2024 there were fluctuations due to the COVID-19 pandemic, but that ultimately, PGE has been escalating its non-labor generation expenses reasonably. This issue was later resolved through the Second Partial Stipulation in this general rate case (GRC) proceeding.[19]

Q. What is PGE's recommendation regarding AWEC's proposal?

A. PGE recommends that the Commission reject AWEC's proposed adjustment and find that PGE's test year forecast of $7,786,223 for Account 553 outside services costs is both reasonable and prudent, especially given the support provided to AWEC throughout discovery and multiple rounds of testimony. Maintenance is essential and prudent to ensure that PGE can reliably deliver energy to its customers and is especially needed as our generation fleet operates at high-capacity factors.

[18] PGE/2000, Loos – Cristea/7-10.
[19] *See* Second Partial Stipulation at 3, No. 3 - Black Box Settlement for O&M.

III. Qualifying Facility (QF) Pass-Through Mechanism

Q. Please provide some background regarding the QF Pass-Through mechanism proposal.

A. PGE proposed the implementation of a QF Pass-Through mechanism in our direct testimony submitted on February 15, 2023.[20] The purpose of PGE's proposal was to establish a mechanism that would address the volumetric and price risk associated with Public Utility Regulatory Policies Act of 1978 (PURPA)[21] mandated QF projects and ensure appropriate sharing of risk associated with QF generation between PGE and its customers.

Q. Did parties raise issues with PGE's proposal?

A. No. Staff supported PGE's proposal and no other party discussed or raised issues with PGE's proposal within the parties' direct testimony.

Q. If parties did not raise concerns, why are you providing surrebuttal testimony on this issue?

A. We are providing surrebuttal testimony to address Staff's new calculation methodology introduced in Staff's rebuttal testimony, Staff Exhibit 3600 at 13.

Q. Did Staff propose an alternative QF Pass-Through method that would be different from PGE's initial proposal?

A. No. Staff did not propose modification to PGE's initial proposal. However, Staff proposed a new calculation methodology that does not meet the intent of the QF Pass-Through mechanism as proposed by PGE and agreed to in concept by Staff.[22]

Q. Was it reasonable for Staff to propose a new calculation methodology in its rebuttal testimony?

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[20] PGE/300, Schwartz-Outama-Cristea/51.
[21] Public Utility Regulatory Policies Act of 1978, 16 U.S.C. §2601 et seq.
[22] Staff/3600, Jent/13 at 6.

A. No. As also mentioned in PGE Exhibit 3500, the Commission requires five rounds of testimony in general rate cases so that Staff and intervenors can identify disagreements with the Company's filing in their first round of testimony and then address the utility's detailed response in their second round of testimony.[23] Staff's introduction of a new calculation methodology for the QF Pass-Through Mechanism in rebuttal testimony, is not consistent with the Commission's established process and the agreed-upon schedule. In addition, Staff's timing provided PGE with limited time to respond and did not allow for other parties an opportunity to respond.

Q. Are there other challenges with implementing Staff's proposed methodology?

A. Yes. As mentioned above, PGE initially proposed the QF Pass-Through Mechanism in direct testimony that supported PGE's 2024 NVPC forecast (i.e., PGE Exhibit 300) because implementing the mechanism would involve direct changes to the NVPC forecast methodology for QFs. However, Staff did not address PGE's proposal in the Annual Power Cost Update (APCU) opening testimony[24] submitted on May 24, 2023. Rather, Staff included a response to PGE's proposal in Staff Exhibit 1300,[25] as part of the UE 416 General Rate Revision procedural schedule. The General Rate Revision procedural schedule provides for a Commission Order target date of December 18, 2023, which does not allow for time to implement any changes to the modeling of the 2024 NVPC forecast. This is because the APCU is on a different procedural schedule that provides for a Commission Order target date of October 30, 2023, and a final MONET Update and 2024 NVPC forecast on November 15, 2023.

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[23] *In the Matter of Avista Corp. Request for a Gen. Rate Revision*, Docket UG 288, Order No. 16-109 at 22 (Mar. 15, 2016).
[24] Staff Exhibits 100, 200, and 300.
[25] Staff/1300, Jent/3-7.

Q. How does Staff propose to calculate the power costs subject to the QF Pass-Through mechanism?

A. While Staff's description of the calculation is not straightforward, PGE confirmed with Staff via discovery that their proposed equation reads as:

- For every hour and specific QF contract, Deferral Amount = (QF generation forecast – QF actual generation) * (Mid-C actual price – QF contract price).

Q. Do you agree with Staff's proposed calculation?

A. No. Staff's formula does not capture QF costs and benefits incorporated in the Net Variable Power Cost (NVPC) forecast that relate to the difference between forward Mid-C price and QF contract costs and, therefore, it does not support a full pass-through of QF-related costs, which is the intent of PGE's proposed mechanism. As previously mentioned, PGE has an obligation under federal and state law to purchase electricity produced by QFs.[26] Therefore, PGE would include generation from any QFs that are operational or expected to become operational before the end of the test year in the NVPC forecast resource portfolio, no matter the price of the contract. MONET would then simulate the economic dispatch of PGE's resource portfolio. Depending on how the QF contract price compares to the forward Mid-C market price, the NVPC forecast can incorporate a cost or benefit associated with each QF contract. Staff's proposed formula does not contemplate the incremental QF cost or benefit that is included in the NVPC forecast.

Q. What is PGE's recommendation regarding the QF Pass-Through Mechanism?

A. PGE opposes Staff's proposal because it does not result in a full pass-through of QF costs and benefits. Additionally, Staff provided their proposed calculation methodology of the QF Pass-

[26] PGE/300, Schwartz – Outama – Cristea/51 at 18-20.

Through amount in their final round of testimony. Consequently, the procedural schedule in this docket does not provide for sufficient time to fully litigate this issue or to implement in the 2024 NVPC forecast a mechanism pursuant to a Commission decision expected around mid-December 2023. Therefore, PGE proposes to withdraw its QF Pass-Through mechanism proposal from this GRC and respectfully requests that the Commission reject Staff's proposed method of calculation. PGE and parties would maintain the right to propose a more detailed mechanism and calculation in future GRCs or annual update tariffs (AUTs).

IV. Qualifications

Q. Mr. Clark, please summarize your qualifications.

A. I received my Bachelor of Science in Mechanical Engineering from the University of Washington. I joined PGE as a mechanical engineer at Trojan Nuclear Plant in 1989. Over my 34-year career at PGE I have held numerous management roles directing thermal, wind, and hydro generation and engineering, and was a director in information technology. I am currently the Senior Director of Thermal Generation and Planning as of January 2022.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
3701	PGE Generation Outside Services Data

Exhibit 3701 has been retained and transmitted in its native format

Information provided in electronic format only

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 416

Compensation

PORTLAND GENERAL ELECTRIC COMPANY

Surrebuttal Testimony of

Anne Mersereau
Tamara Neitzke

September 11, 2023

Table of Contents

I. Introduction

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

A. My name is Anne Mersereau. My position is Vice President, Human Resources, Diversity Equity and Inclusion.

My name is Tamara Neitzke. My position is Director of Total Rewards in the Human Resources Department.

Our qualifications appear at the end of our Direct Testimony PGE Exhibit 500 at 40-41.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is three-fold: (1) we provide continued support for PGE's Total Labor and Incentives costs for the 2024 test year, (2) we respond to rebuttal testimony from the Public Utility Commission of Oregon (OPUC or Commission) Staff (Staff) regarding Total Labor and Incentives, and (3) we respond to Citizens' Utility Board of Oregon (CUB) rebuttal testimony regarding PGE's employee discount.

Q. How is the remainder of your testimony organized?

A. After this introduction, we have four sections:

- Section II: Overview and Summary
- Section III: Total Labor Requirements
- Section IV: Incentives
- Section V: Employee Discount

II. Overview and Summary

Q. Please provide a summary of your testimony.

A. Section III of our testimony addresses arguments and two proposed adjustments from Staff related to total labor. Specifically, we respond to Staff's analysis and demonstrate that, in effect, Staff's work on the matter supports PGE's arguments and stance. Further, we continue to support Staff's adoption of a modern, holistic approach to labor expense modeling.

Section IV of our testimony addresses arguments and a proposed adjustment from Staff related to employee incentives. Specifically, the shortcomings of Staff's simplistic modeling which fails to include inputs such as inflation and employee headcount.

Section V of our testimony addresses arguments and the proposed adjustment by CUB related to PGE's long-standing employee discount program. Specifically, we continue to argue and support the fact that this program is a low-cost and effective recruitment and retention benefit, that employees value.

Q. What do you recommend of the Commission?

A. We recommend that the Commission reject Staff's arguments and adjustments and approve the recovery of all costs originally forecasted by PGE related to total labor and incentives. Not only will we show that Staff's proposed adjustments lack merit, but that they also relate solely to matters already settled by stipulation, which PGE entered in good faith, or are otherwise resolved. Additionally, we continue to recommend that the Commission reject CUB's proposal to reduce our employee discount benefit from 25% to 5%. We instead respectfully request the Commission continue to support PGE's ability to offer and collect the costs associated with this long-standing, and industry-commensurate benefit at the same level it has been offered for more than half a century.

III. Total Labor Requirements

Q. Please state Staff's proposed adjustment to the remaining portion of Wages and Salaries.

A. Consistent with their opening testimony, Staff proposes a rate base adjustment to Wages and Salaries of ($458,856) and a rate base adjustment to full time employees (FTEs) of ($3,518,704).[1]

Q. Are there any new elements to Staff's proposal for adjusting Wages and Salaries?

A. Yes. In their rebuttal testimony, Staff proposes for the first time that these adjustments result in a *permanent* reduction to PGE's regulated rate base,[2] which would result in a write-off for accounting purposes associated with these amounts.

Q. How did Staff derive its proposed adjustment?

A. Staff's proposed adjustment to Wages and Salaries was developed utilizing Staff's 3-Year Wages and Salaries Model. The adjustment associated with FTEs was derived from a March 30, 2023 headcount number provided as part of PGE's response to OPUC Data Request No. 421.

Q. What specific data did Staff rely upon to support their wages and salaries arguments in Staff Exhibit 3600?

A. Staff's testimony focused on PGE's wages and salaries budget data along with both budget and actual FTEs.

[1] Staff/3600, Jent/10 at 20-22.
[2] *Id*.

Q. What does Staff assert utilizing this data?

A. Using PGE's labor budget data, Staff argues that straight-time FTEs accurately reflect PGE's Total Labor requirements because Staff Exhibit 3600, Figure 1 demonstrates that PGE's "biggest ticket item is straight-time labor."[3]

Q. What does Staff's analysis neglect to include?

A. Staff's analysis does not include PGE's actual labor costs.[4] As such, while in total it is accurate that straight-time employees are still PGE's single largest wages and salaries expense, Staff's selective presentation of this data belies an important fact—as seen below in Table 1—that the fastest growing, and in fact *only* category that experienced growth by percent of PGE's Total Labor during the same period that Staff references is contract labor.

Table 1:
Percent of Total Labor, Actuals

	2019	**2020**	**2021**	**2022**
Straight-time	79.6%	70.6%	60.5%	65.2%
Overtime	6.8%	6.2%	6.8%	5.9%
Contract Labor	10.8%	11.6%	22.4%	18.2%

Q. How does Table 1 compare to the data that Staff presented as Figure 1 of Staff Exhibit 3600?

A. PGE's Table 1 presents the data as actuals, while Staff's Figure 1 utilizes PGE's budgets. Staff's perspective would suggest that contract labor made up only 5.8% of PGE's wages and salaries in the year 2022, or approximately $23.2 million. However, actuals demonstrate that in 2022, contract labor was *three times that amount* (i.e., 18.2% or approximately $77.9 million of PGE's wages and salaries). By selectively focusing on budget information rather than PGE's actual costs, Staff's analysis largely discounts this critical component of our wages

[3] Staff/3600, Jent/7 at 7-13.
[4] *Id*.

and salaries. To put contract labor costs in perspective with other compensation-related components, Staff reviewed PGE's incentives ($20.4 million test-year request), overtime ($24.3 million test-year request), and health and wellness benefits ($54.6 million test-year request), while inconsistently appearing to suggest that PGE's contract labor is too insignificant to be included in their analysis simply because straight-time labor is a higher cost to PGE.

Q. Staff neglected to discuss PGE's contract labor in their opening testimony. Does Staff discuss PGE's contract labor within their rebuttal testimony?

A. No. While PGE has specifically discussed this key component of our labor costs in both initial and reply testimonies and clearly demonstrated its relevance, Staff continues to ignore both contract labor costs and their impact on PGE's year-over-year total labor.

Q. Why is it significant that Staff continues to fail in addressing contract labor?

A. It means that all of Staff's analysis throughout this proceeding has been incomplete, which displays a bias in their results. While Staff does acknowledge that PGE "makes several arguments stating that the use of straight time FTE does not accurately reflect PGE's total labor requirements,"[5] they fail to address the substance of PGE's arguments. Instead, Staff confusingly only responds that straight-time labor is "the biggest ticket item."[6] As we pointed out in both our opening and reply testimony, PGE defines total labor as straight-time, overtime, and contract labor because an evaluation of labor costs only in terms of FTE or headcount does not reflect the realities of the current labor market, nor does it reflect the types of labor PGE utilizes to meet business needs.[7]

[5] Staff/3600, Jent/7 at 7-10.
[6] *Id*. at 10.
[7] PGE/1800, Mersereau-Neitzke/5.

In both their opening and rebuttal testimony, Staff does not refute that recognizing contract labor presents a more accurate picture of PGE's current and projected labor costs. Instead, they myopically focus on headcount to support an adjustment, recommending a decrease in wages and salary costs because "PGE has historically budgeted more FTEs than is necessary."[8] Staff is making an isolated reduction to straight-time labor alone without considering the way contract labor is used to fill the gap.

Q. What does Staff say about PGE's FTE budgets compared to actuals?

A. Staff states that PGE's FTE actuals have been higher than our budgeted FTEs every year since 2020 and claim that this is evidence of over-budgeting.[9]

Q. How does PGE respond?

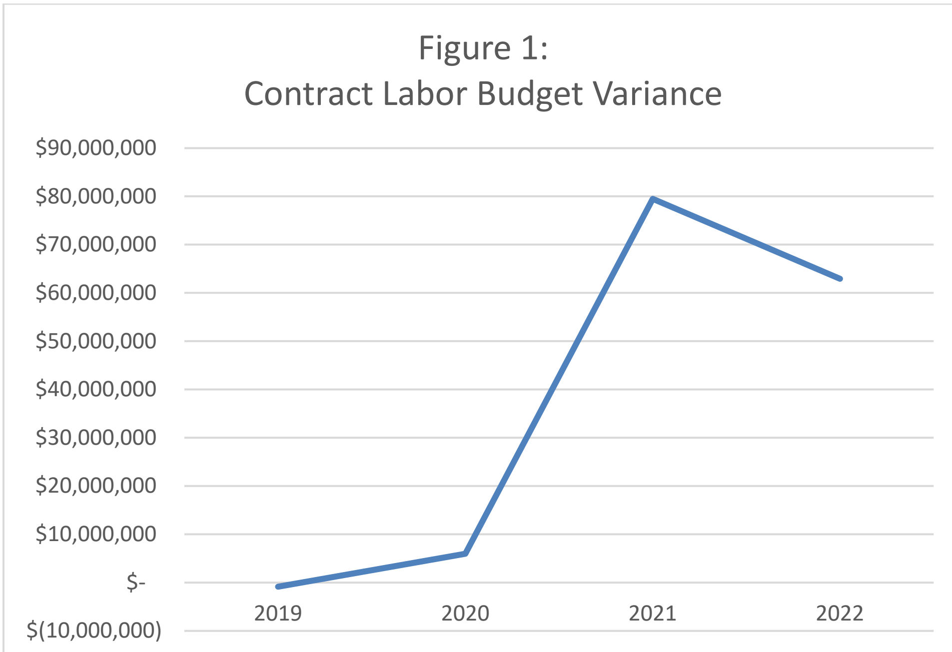
A. The data Staff presents actually supports the basis of many of PGE's arguments so far in this proceeding. Beginning in 2020, there was a major shift in the employment market (i.e., the COVID-19 pandemic along with the "great resignation") that has made filling all positions with regular full-time employment extremely challenging. PGE budgets for positions that we plan to fill with full-time regular employees and when we are unable to find qualified candidates this creates the variance that Staff points to. A look at Figure 2 in Staff's rebuttal testimony shows that prior to 2020, PGE's actuals for FTEs in 2018 and 2019 were higher than what was forecast.[10]

Q. Does this mean that PGE is over-budgeting its labor costs?

A. No. When PGE cannot find a qualified candidate for open positions, contract labor, and to a lesser extent overtime, may be utilized to complement our straight-time workforce. Figure 1

[8] Staff/3600, Jent/7 at 7.
[9] *Id.*/8 at 7-8.
[10] *Id.*/8.

below demonstrates that for 2020, 2021, and 2022 (i.e., the years Staff argues we over-budgeted FTEs)[11] PGE spent well over our contract labor budget. In contrast, for 2019, the last year in which PGE met its FTE budget, we accomplished modest savings in contract labor.



In summary, for every year that Staff points to FTE over-budgeting by PGE, our contract labor spend was <u>above</u> budget (by an average of $50 million), demonstrating the clear connection between the two figures and more than accounting for the dollars that would have been spent on unfilled budgeted positions. In fact, if you convert contract labor dollars into an average amount per fully loaded FTE (i.e., the average cost of a PGE FTE including wages, benefits, and incentives), $50 million of contract labor equates to approximately 322 FTEs[12] – slightly more than the amount Staff suggests that we over-budgeted in 2020 and 2021, and 201 FTE more than our 2022 forecast to actuals variance.

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[11] Staff/3600, Jent/8 at 7.

[12] $50 million divided by PGE's cost per FTE (i.e., $155,454), for more information including PGE's cost per FTE calculation, see PGE Exhibit 3801.

Q. How have PGE's contract labor actuals compared to budget amounts in 2023?

A. Through the month of August, PGE has overrun its contract labor budget by approximately $14.5 million (i.e., $42.7 million in actuals versus year-to-date budget of $28.2 million). This amounts to PGE spending approximately $1.8 million above budgeted amounts for contract labor every month.[13] Thus, assuming a similar trend, through the end of the year, PGE will have spent approximately $21.7 million above its 2023 contract labor budget of $37.1 million, or $58.8 in total.

Q. Is it likely that PGE will go over the contract labor forecast in 2024?

A. Yes. As Staff points out in their Exhibit 1300, PGE's test year contract labor forecast is very modest at only $36.9 million,[14] which is approximately $41.0 million below 2022 actuals. In fact, the forecast is well below actual amounts for each of the last three years, as shown below in Table 2 and, as we state above, is well below the expected amounts for 2023.

Table 2
Contract Labor Actuals 2019-2022 ($millions)

	2020	**2021**	**2022**
Actuals	41.0	94.7	78.0
Amount Below 2024 Test Year	4.1	57.8	41.0

It is clear that PGE's need to supplement its budget of straight-time employees with contract labor is not anomalous and as PGE continues to experience challenges in filling open positions with regular full-time employees it seems very likely that once again contract labor will be necessary to fill gaps in our workforce resulting in increased spending over forecast.

[13] $14.5 million divided by eight months year to date.
[14] Staff/1300, Jent/21 at 11.

Q. If PGE is aware that contract labor is being under-budgeted, why not adjust the budget?

A. PGE can only budget for each position one time and because the preferred employee is a regular full-time employee rather than a contract employee that is what is reflected in the budget. If PGE were to budget for all the FTEs we plan to hire, while also basing our contract labor budget on the year before, we would effectively budget twice for work that is only completed once. Contract labor fills the gaps in PGE's straight-time workforce, and straight-time employee availability is based largely on the current job market.

As we testified to and demonstrated in PGE Exhibits 500 and 1800, the current job market does not allow for the filling of all open positions at PGE. This persistent challenge is a key factor for why we have evolved our perspective on tracking and managing labor requirements. Shifting towards a complete view of total labor that includes straight-time, overtime, and contract labor allows us greater flexibility to navigate and balance the current economic conditions against the work we must accomplish. Put simply, by treating the dollars budgeted to each labor category as fungible, PGE can focus on an accurate *total* labor budget, rather than isolate and piecemeal contract labor, overtime, or straight-time labor budgets. Staff's rigid models for Wages and Salaries and FTEs no longer fully reflect PGE's labor requirements in the current employment market, as they lack the flexibility to account for the interchangeability of our labor resources (i.e., straight-time, overtime, <u>and</u> contract labor).

Q. Does PGE's test year forecast represent a large increase in total labor costs?

A. No. As noted in PGE Exhibit 1800, after accounting for inflation, PGE's test year forecast represents an overall $25.5 million <u>decrease</u> in total labor expense compared to base year actuals, a fact that Staff has not acknowledged throughout this proceeding.

Q. Has PGE, Staff, and parties resolved any issues specifically associated with capital additions in this proceeding?

A. Yes. All capital additions to rate base included in this proceeding have been addressed in settlement agreements that are pending approval by the Commission,[15] or are otherwise resolved.

Q. Does this mean that Staff is proposing to permanently reduce capital already settled through stipulation?

A. Effectively, yes. In rebuttal testimony, Staff recommends a permanent rate base adjustment to wages and salaries of $458,856 and a permanent rate base adjustment to FTE of $3,518,704.[16] However, only wages and salaries capitalized through project additions can be permanently reduced. Therefore, the amounts Staff seeks to permanently reduce are essentially a part of the capital additions and projects that have already settled through stipulations filed to date. So, to now adjust those amounts undermines the previous settlement agreements made between PGE, Staff, and parties. Additionally, because they have not demonstrated that their proposed reductions are related to the imprudence of any capital project in this case, a proposal for a *permanent* reduction is unsupported.

Q. Please summarize PGE's position regarding Total Labor expense.

A. Staff's proposals to adjust both wages and salaries and FTE do not stand up to scrutiny when PGE's labor expense is viewed in its totality. When considered holistically, it is clear PGE's total labor request represents an inflation-adjusted $25.5 million decrease in expenses compared to 2022 actuals. Likewise, we have clearly demonstrated that contract labor substitutes for FTEs when PGE is unable to fill open positions. However, rather than respond

[15] *See* UE 416, Second and Third Partial Stipulations
[16] Staff/3600, Jent/10 at 18-22.

to PGE's evidence, Staff remains focused solely on two metrics –the output of their 3-Year Wages and Salaries model and a PGE headcount obtained by Staff at an arbitrary point in time. This myopic analysis allows Staff to view each piece of our request in isolation, which results in an inaccurate view of PGE's total labor. Additionally, it is unclear to PGE why Staff would continue to propose this adjustment, as we believe these matters to be settled. Staff's proposal to now apply a permanent downward adjustment of <u>any</u> amount from our 2024 test year Total Labor expense is unsupported and unreasonable and should be rejected.

IV. Incentives

Q. Please state Staff's proposal related to capitalized incentives.

A. Staff proposes a $2.2 million permanent rate base adjustment to incentives.

Q. Did Staff recommend this adjustment be applied on a permanent basis within their opening testimony?

A. No. While Staff fails to highlight this as a new proposal in their testimony, the fact is, similar to their labor proposal, this is Staff's first mention of a permanent adjustment.

Q. Why is this distinction important?

A. As we mention above in Section III, should PGE be ordered to make a permanent reduction, it will result in a write-off for PGE.

Q. How did Staff determine the proper size for their adjustment?

A. Staff took the average of PGE's last three years of actual incentive costs.

Q. Does Staff's model for incentives consider employee headcount?

A. No. Although Staff's wages and salaries adjustment considers employee headcount, their incentives model does not normalize for changes to PGE's workforce.

Q. Does Staff's analysis consider the effects of inflation?

A. No. PGE pointed to this omission in PGE Exhibit 1800,[17] but Staff does not address this in their rebuttal. It is inconsistent to apply a CPI adjustment to wages and salaries and not apply the same adjustment to incentives.

Q. Does Staff offer any new analysis in Exhibit 3600?

A. Yes. Staff points out that PGE's 2023 Incentives budget is higher than historical actuals.[18]

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[17] PGE/1800, Mersereau – Neitzke/16 at 8.
[18] Staff/2600, Jent/10 at 10-14.

Q. Does it make logical sense that 2023 budget incentives would be higher than historical actuals?

A. Yes. PGE budgeted for an approximate 7% increase in our workforce from 2022 actuals to 2023 budget. Pairing that with the effects of inflation, it logically follows that our budget for incentives would be higher than the previous year's actuals. In fact, it follows that budgeted incentives will always be higher than previous actuals absent a shrinking workforce, a deflationary environment, or both. In short, and speaking generally, as wages and salaries increase with inflation – which Staff's own model clearly accounts for – so will incentives.

Q. Are PGE's incentive costs increasing faster than its compensation expenses as a whole?

A. No. PGE's test year forecast for non-officer incentives represents 3.6% of PGE's total compensation request which, as shown in Table 3 below, is smaller proportionally than requested in Docket No. UE 394, our last General Rate case, and only one-tenth of a percent higher than the average across our last three rate cases.

Table 3
Non-Officer Incentives as a Percent of Total Compensation

UE 319	UE 335	UE 394	Average
3.3%	3.3%	3.9%	3.5%

Q. Are these incentives a part of already settled capital additions and projects?

A. Yes. Similar to the wages and salaries amounts that Staff proposes to permanently disallow, these incentive costs are effectively a part of capital additions to rate base that PGE, Staff, and parties have already settled through stipulation and therefore Staff's proposal appears moot.

Q. Please summarize PGE's position on incentive pay.

A. PGE's incentive pay is an important part of a competitive total compensation package. Incentive payouts are modified for high-performing employees based on competitively pre-established performance goals and intended to drive outcomes and performance. While Staff is correct that incentive expense has increased, they fail to account for employee headcount and inflation, while ignoring that incentives are not growing as a percentage of PGE's total compensation. The adjustments made by Staff are unreasonable and would harm PGE's ability to attract and retain qualified employees.

V. Employee Discount

Q. Please summarize CUB's position on the Employee Discount

A. CUB continues to recommend that PGE's employee discount be reduced from 25% to 5%. CUB indicates they will be seeking a similar reduction for other energy utilities within a future general case. CUB does not believe this program is valued by employees and argues that PGE has failed to provide evidence that this program is a major driver in our ability to attract and retain employees. Finally, CUB argues there is a clear link between PGE's income-qualified bill discount (IQBD) program and PGE's employee discount, as they both create upward pressure on overall cost-of-service prices.

Q. Does PGE agree that the fact that PacifiCorp and Northwest Natural offer similar discounts is "moot?"[19]

A. No. PGE competes with these neighboring utilities on a regular basis for talent and these utilities currently offer an employee discount that is similar to PGE's current offering of a 25% discount. CUB's statement that they will also seek a reduction to those utilities' employee discount offerings at some future date does not change this fact.

Q. How does PGE respond to CUB's argument that this offering is not valued by employees?

A. CUB's support for their argument seems to rest on the fact that PGE is still able to hire and retain employees who do not live in PGE's service territory. PGE's employee discount offering is a very low-cost component of our overall competitive offering provided to assist in the attraction and retention of employees. While there may be "hundreds of employees who

[19] CUB/500, Gehrke/2 at 11.

live outside of PGE's service territory,"[20] the fact is a much larger number of employees do live within PGE's service territory and receive this discount. Approximately 2,900 current and retired employees currently receive this discount.

Q. Does PGE leverage our employee discount as part of our recruiting efforts?

A. Absolutely. We publicly post this benefit offering on our career site and consistently include this information within benefit summaries we share with potential candidates for employment. PGE's employee discount also helps with retention, as employees do not qualify until they have been at PGE for six months.

Q. You've stated previously that this program is a low-cost offering compared to other means of compensation. Please elaborate.

A. The employee discount in total amounts to approximately $1.5 million per year. This compares to PGE's total benefits forecast for 2024 of approximately $106.8 million, or approximately 1.4% of PGE's total benefits. When compared to PGE's total compensation forecast for 2024 the ratio shrinks to approximately 0.3%.[21] In summary, PGE's employee discount remains an important and low-cost tool that helps to both attract and retain employees and it is a tool we leverage when recruiting for increasingly hard to find talent.

[20] *Id.* at 15.
[21] Based on PGE's total compensation forecast of $560.1 million as provided in PGE Exhibit 500, Table 1.

Q. CUB argues that because they propose a reduction to 5% and not an elimination, they've addressed PGE's argument that employee discounts are common offerings. How do you respond?

A. It is not just the fact that we offer the discount that matters, it is also the level of discount we offer that allows this to be an effective tool for hiring and retention and a valued part of PGE's benefit offerings.

Q. What is CUB's argument for comparing PGE's employee discount to PGE's IQBD program?

A. CUB's argument is effectively that because both programs will create rate pressure for all other customers, it is reasonable to reduce PGE's employee discount to 5%. In other words, PGE employees should be stripped of a low-cost, long-serving, and valued benefit because we have a different program offering a structured benefit to customers in need.

Q. How do these two programs compare from a percentage and a total dollar basis?

A. As we stated above and in previous rounds of testimony, our employee discount is 25% and totals approximately $1.5 million. This compares to PGE's Exhibit 4100, in which PGE's current recommendation for IQBD is a 60% discount for the lowest tier of participants and an estimated cost in 2024 of roughly $50 to $60 million. Comparing participant sizes, as we stated above, PGE's employee discount currently has approximately 2,900 active and retired employees enrolled, while the IQBD program has a current active enrollment of 62,000 households and an estimated 160,000 households that are eligible. It is clear that PGE's IQBD program offers a greater discount, has a far greater level of eligible customers and costs substantially more.

Furthermore, this is a program that has been in place at the 25% level for PGE employees and retirees over 50 years. The existence of a new program for customers that is significantly more costly that allows for discounts to a subset of PGE customers is unrelated. The fact is, that while the dollar value of PGE's employee discount is small and will do little to defray the costs of PGE's IQBD program, PGE employees value this benefit and it is a cost-effective tool for recruiting, hiring, and retention. CUB's recommendation if adopted will represent a significant change to a long-standing and venerable benefit offering.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
3801	Cost per FTE calculation

Exhibit 3801 has been retained and transmitted in its native format

Information provided in electronic format only

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 416

Insurance

PORTLAND GENERAL ELECTRIC COMPANY

Surrebuttal Testimony of

Greg Batzler
JP Agnesse

September 11, 2023

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I. Introduction

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

A. My name is Greg Batzler. I am a Senior Regulatory Consultant in Regulatory Affairs at PGE. My qualifications were previously provided in PGE Exhibit 200.

My name is JP Agnesse. I am the Manager of the Insurance and Risk Finance department at PGE. My qualifications were previously provided in PGE Exhibit 1900.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to respond to the rebuttal testimony provided by the Alliance of Western Energy Consumers (AWEC) and the Public Utility Commission of Oregon (OPUC or Commission) Staff (Staff) (collectively, Parties) with respect to PGE's 2024 test year property insurance forecast.

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

A. We address the following issue:

- Section II: Property Insurance

II. Property Insurance

Q. Please summarize AWEC's proposal regarding PGE's property insurance.

A. In their opening testimony, AWEC proposed using known and measurable 2022 property insurance premium amounts instead of PGE's 2024 test year forecasted amount, resulting in a $6,205,664 adjustment to PGE's 2024 property insurance costs.[1] AWEC also argued that the inclusion of property insurance related to plant assets (i.e., Clearwater) that are not included in this general rate case (GRC) is unwarranted.[2] In PGE's reply testimony, we agreed with AWEC's latter argument and proposed a $325,100 adjustment to remove amounts related to Clearwater.

In their rebuttal testimony, AWEC has now proposed using "known and measurable" 2023 property insurance premium amounts,[3] which, based on AWEC's review of PGE's response to AWEC Data Request (DR) No. 132, Confidential Attachment A,[4] would result in a $1,788,313 reduction to PGE's 2024 forecasted property insurance premium of $16,597,053. Additionally, it appears that AWEC's most recent proposed adjustment still includes amounts related to Clearwater even though they initially proposed (and PGE subsequently agreed) to remove these amounts.

Q. How did AWEC arrive at their proposed $1,788,313 reduction?

A. In their rebuttal testimony, AWEC provided zero analysis or support for their proposed reduction, but instead simply stated that it was based on review of PGE's response to AWEC DR No. 132, Confidential Attachment A.[5] As requested, PGE's response to AWEC DR

[1] AWEC/200, Mullins/2 at Table 1 and AWEC/200, Mullins/17 at 9-10.
[2] AWEC/200, Mullins/17 at 13-14.
[3] AWEC/600, Mullins/13 at 12-15.
[4] A copy of PGE's response to AWEC DR No. 132 is provided as confidential PGE Exhibit 3901.
[5] AWEC/600, Mullins/13 at 13-15.

No. 132 provided support for PGE's 2024 property insurance test year forecast with a handful of 2023 budget data points.

AWEC's claim is based on a calculation that reverts PGE's 2024 test year request to actual 2023 policy levels (which were not known or provided in PGE's response to AWEC DR No. 132). Therefore, in an attempt to understand and seek clarification as to how AWEC arrived at their proposed reduction, PGE sent a DR seeking a description and explanation of the specific information used by AWEC in PGE's response to AWEC DR No. 132 to calculate and support their proposed reduction.[6]

Q. How did AWEC respond?

A. AWEC responded by simply providing a version of PGE's response to AWEC DR No. 132, Confidential Attachment 132-A in which it appears AWEC attempted to revert PGE's 2024 forecast to 2023 "actuals" based on a handful of 2023 budget data points. AWEC's proposed adjustment, regardless of the fact that it contradicts their own initial proposal to remove amounts related to Clearwater, is unsupported, unjustified, and not based on the realities of current economic conditions.

Q. Have any other Parties in this proceeding expressed an opinion on AWEC's proposal?

A. Yes. Staff opposes AWEC's proposal and acknowledges that "insurance premiums generally increase for everyone every year and to generically request no increase seems untenable."[7] Staff proposes no adjustment to PGE's initial 2024 property insurance test year forecast of $16,597,053 except for the removal of $325,1000 related to Clearwater to which PGE agrees. Consequently, PGE's 2024 test year property insurance request becomes $16,271,953, a sum

[6] A copy of AWEC's response to PGE DR No. 13 is provided as confidential PGE Exhibit 3902.
[7] Staff/3000, Chipanera/9 at 16-19.

already aligned with the amount outlined in PGE Exhibit 1900 and now concurred with by Staff as well.

Q. AWEC asserts that PGE "overstates the cost of property insurance since the 2024 policy rate increases it has included in revenue requirement for the 2024 insurance year would only apply to part of the Test Period."[8] How does PGE respond?

A. AWEC's assertion is incorrect. While PGE's property insurance policy coverages generally do not align with a calendar year, PGE accurately matches these costs with the services provided using accrual basis accounting as prescribed under Generally Accepted Accounting Principles (GAAP).

Q. How does accrual basis accounting reflect costs?

A. Accrual basis accounting recognizes and records expenses (and revenues) in the period they occur. To properly reflect PGE's insurance policy costs, which are paid in lump sums, PGE initially records these costs in a prepaid account on the balance sheet, which is not included in PGE's revenue requirement. Then, consistent with accrual basis accounting the costs are amortized (i.e., spread) on a monthly basis to PGE's income statement, consistent with the period of coverage. As such, PGE's insurance costs which are included in PGE Exhibit 601 and PGE Exhibit 201, only include amounts that are relevant to the period of coverage.

Q. Would PGE be allowed to budget or record insurance amounts in the manner AWEC describes?

A. No. Accrual basis accounting is the only method allowed under GAAP and is required by the Securities and Exchange Commission (SEC) for publicly traded companies. Recording costs in the manner described by AWEC would be in violation of GAAP.

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[8] AWEC/600, Mullins/12-13 at 21-2.

Q. Why does PGE discuss insurance in terms of policy renewal amounts in testimony, rather than in terms of revenue requirement amounts?

A. We discuss policy years because it is consistent with how these coverages are viewed internally and with how our insurance department assesses and negotiates these costs.

Q. When discussing how PGE responded to their initial proposal, AWEC solely notes that "PGE stated that I used the 2022 premiums, not the 2023 premiums, and that therefore my analysis was inaccurate."[9] How does PGE respond to this statement?

A. This statement is partial, misleading, and fails to represent PGE's comprehensive response found in PGE Exhibit 1900. To summarize, PGE provided an extensive and robust reply to AWEC's initial proposed adjustment. Alongside acknowledging AWEC's erroneous year reference, PGE also:

a. Noted why it is not appropriate to use current premium amounts for the 2024 forecast simply because using 2024 forecast premium amounts is, in AWEC's opinion, not justified;

b. Detailed notable changes in the commercial property insurance market since PGE established our 2024 forecast in the third quarter of 2022;

c. Articulated the impracticality of expecting no 2022-2024 property insurance premium rise;

d. Detailed our methodology for applying escalation factors to property insurance forecasts (counteracting AWEC's unsupported claim that adjustments applied to arrive at our 2024 forecast were not supported by analysis);

[9] AWEC/600, Mullins/12 at 1-3.

e. Explained the alignment of our methodology with industry peers for establishing property insurance forecasts;

f. Noted consistency with historical property insurance premium increase justifications and methodology;

g. Compared 2024 test year forecast with historical actuals, demonstrating alignment; and

h. Offered a rationale for concluding that changes in PGE's property insurance premiums are substantiated with analysis-backed adjustments.

Q. Are rising property insurance rates and associated driving factors unique to PGE and the utility industry?

A. No. Besides PGE and other utilities, homeowners are also grappling with escalating premium costs and lack of insurability due to insurers seeking to manage their risk exposure. In California, State Farm is no longer offering new property and casualty insurance, Allstate has stopped selling new home, condo, or commercial policies, and Liberty Mutual pulled its business owner policy line of coverage.[10] Additionally, Farmers Insurance and more than a dozen other insurers have done the same in Florida.[11]

AWEC's assertion that PGE's property insurance expenses should remain at known and measurable levels blatantly overlooks PGE's historical and forecasted premiums, prevailing

[10] *See* Jordan Hart & Josée Rose, "allstate joins State Farm in no longer offering new home insurance policies in California over climate risks," Business Insider (Jun. 5, 2023) https://www.businessinsider.com/state-farm-cuts-new-home-insurance-california-citing-wildfire-risk-2023-5; *See also* Steve Hallo, "More insurers exiting California's home insurance market," (August 16, 2023) https://www.propertycasualty360.com/2023/08/16/more-insurers-exiting-californias-insurance-market/

[11] *See* Rob Wile & Jasmine Cui, "Homeowners in California and Florida are running out of options to protect their homes" NBC News (Jun. 17, 2023) https://www.nbcnews.com/business/consumer/homeowners-go-without-insurance-in-states-where-its-too-expensive-rcna88578

market price shifts, PGE's growing asset base, PGE's losses, industry-wide challenges, and broader macroeconomic influences affecting all, beyond utilities.

Q. What is PGE's recommendation to the Commission regarding 2024 property insurance premiums?

A. We recommend that the Commission reject AWEC's proposed adjustment, except for the $325,100 discussed above that PGE has already agreed to remove from its request. Both PGE and Staff agree that AWEC's proposal seems untenable and agree on (or propose no adjustments to) PGE's original 2024 test year property insurance request of $16,271,953.[12] AWEC's proposal to use "known and measurable" premium amounts because 2024 forecast amounts are not justified and not supported by analysis is unreasonable and unjustified. This is especially true considering PGE's historical and forecasted property premiums, current market pricing trends, PGE's growing asset base, PGE's losses, industry-wide challenges, and broader macroeconomic influences affecting all, beyond utilities. Setting PGE's 2024 property insurance premiums to current levels would result in a significant under-recovery of PGE's prudently incurred property insurance costs, which serve to protect PGE and customers from unforeseen property damages, liability claims, and potential financial losses.

Q. Does this conclude your testimony?

A. Yes.

[12] This accounts for the removal of $325,100 related to Clearwater.

List of Exhibits

PGE Exhibit	Description
3901C	PGE's response to AWEC DR No. 132
3902C	AWEC's response to PGE DR No. 13

Exhibit 3901C contains confidential information and is subject to

Modified General Protective Order 23-039

Exhibit 3901C has been retained and transmitted
in its native format

Information provided in electronic format only

Exhibit 3902C contains confidential information and is subject to

Modified General Protective Order 23-039

Exhibit 3901C has been retained and transmitted in its native format

Information provided in electronic format only

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 416

Return on Equity

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony of

Bente Villadsen

September 11, 2023

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I. Introduction

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

A. My name is Bente Villadsen, and I am a Principal of The Brattle Group in Boston, Massachusetts. I provided direct and reply testimony in Docket No. UE 416 earlier this year. I directly sponsored the testimony found in Section IV of Exhibits 1000 and 2400, and I am directly sponsoring the testimony in this Exhibit. My qualifications can be found in PGE Exhibit 1003.

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of my testimony is to continue to support PGE's position on its recommended return on equity (ROE).

I have reviewed and am responding to the Staff's Rebuttal Testimony of Mr. Matt Muldoon, Staff Exhibit 2900 (Muldoon Rebuttal) on behalf of Oregon Public Utility Commission Staff (Staff), and the Rebuttal Testimony of Mr. Christopher C. Walters, AWEC-CUB Exhibit 200 (Walters Rebuttal) on behalf of the Alliance of Western Energy Consumers and Oregon Citizens' Utility Board (AWEC-CUB). It is my understanding that Walmart Inc. did not file rebuttal testimony.

Q. How is the remainder of your testimony organized?

A. After this introduction, we have two sections:

- Section II: Overview and Summary
- Section III: Return on Equity

II. Overview

Q. Please provide an overview of your position on ROE.

A. PGE maintains that its recommended ROE of 9.8% in this rate case is appropriate, and support for this value has only strengthened since PGE provided opening testimony. Authorized ROE values across the industry have continued to rise through the first two quarters of 2023 among the utilities with which PGE competes for capital. We continue to emphasize that a proposal of 9.8% is based on the risk profile consistent with the policy proposals PGE makes within the rate case, particularly the proposal to revise PGE's power cost adjustment mechanism (PCAM) since PGE is currently an outlier with a much higher risk profile relative to its peers – nearly all of which do not have this type of risk-bearing mechanism.

Q. Did any party change their position on the return of equity?

A. Yes. Staff re-ran its model and is now recommending a return on equity of 9.4% as compared to a recommendation of 9.0% in its Opening Testimony.[1] AWEC-CUB continue to recommend an allowed ROE of 9.5%.[2] Consequently, the current recommendations for the allowed ROE are as displayed in Figure 1.

Figure 1
Recommended Allowed ROE

	PGE (Villadsen)	Staff (Muldoon)	AWEC-CUB (Walters)
Recommended ROE	9.8%	9.4%	9.5%

The recommendations of both Staff and AWEC-CUB are below that currently allowed integrated electric utilities, which for the first eight months of 2023 averaged 9.78%,[3] while PGE's requested ROE is in line with what has recently been allowed for similarly situated

[1] Staff/400, Muldoon/25.
[2] AWEC-CUB/200, Walters/1-2.
[3] Exhibit 4003C S&P Global Intelligence as of September 2, 2023. Staff uses the average authorized ROE for all electric utilities (including distribution only and limited rider issues) as 9.56 percent for the first six months of 2023.

integrated electric utilities. I also note that the average equity percentage associated with the allowed ROEs for 2023 year-to-date was 51.58%. Again, PGE requested and has now settled for a lower figure of 50%. Despite the similarly situated ROE comparisons and increased interest rates, Staff recommends a lower ROE than what PGE currently is allowed an opportunity to earn and AWEC-CUB is, despite the increase in interest rates and allowed ROEs, recommending PGE only be allowed the same ROE as in Docket No. UE 394.[4]

[4] The previous general rate case was filed July 9, 2021, at which time interest rates were substantially below those at the time of this filing. For example, the 20-year Treasury bond yield was below 2% in July 2021 and is 4.46% as of August 2023. *In the Matter of Portland General Electric Company Request for a General Rate Revision*, Docket UE 394, Initial Utility Filing (July 9, 2021).

III. Return on Equity

A. Summary

Q. Please summarize your surrebuttal testimony.

A. Having reviewed the rebuttal testimonies of Mr. Muldoon and Mr. Walters, as well as data on recent economic developments, I summarize my findings as follows:

1. Continue to find that PGE's requested return on equity of 9.8% is not only reasonable but conservative given today's financial markets.[5]
    - Market measures indicate that the ROE has increased since PGE was last awarded an ROE. This occurred as Treasury bond yields have increased and growth rates for electric utilities are up while the economy-wide growth remains virtually the same.
    - During the first eight months of 2023, the average allowed ROE for integrated electric utilities was 9.78% on an average of 51.58% equity, so PGE's requested ROE is very much in line with nationwide developments and may be conservative.
2. Staff reran its model and is now recommending an allowed ROE of 9.4%. However, while Staff disputes my critique of the reliance on one model, it remains the case that Staff uses only the Discounted Cash Flow (DCF) model and not alternative models' measures of the cost of equity. Staff uses the Capital Asset Pricing Model (CAPM) as a check, so it becomes vital it is implemented using best practices as discussed below.

[5] See Section III.B below for details.

3. Staff states that the Commission has previously ruled that "the geometric average should be used to derive the market risk premium when CAPM is focused on a holding period greater than one year."[6]

   However, I note that the citations related to the Commission's position on this dates back to 1987, 1993, and 1994.[7] Since then, financial economics has specifically considered this issue and rejected the use of a geometric average based market risk premium (MRP). Consequently, I find that it is necessary to rely on the best possible practices in financial economics, which I also discuss below.

4. AWEC-CUB claims that Value Line betas spiked due to an anomalous event (COVID-19) and are "out of line with what is normal."[8] If that is AWEC-CUB's position, then it is imperative that AWEC-CUB undertakes a statistical analysis of the data and demonstrate the abnormality of the betas or underlying data and then determine a methodology to appropriately measure the **current** systematic risk of the sample companies. AWEC-CUB has not done so and simply uses betas that date back upward to 10 years. This is not appropriate as we do not know if those betas address a real concern.

In the remainder of this testimony, I only address issues not previously addressed in my reply testimony and critiques of my reply testimony. Consequently, I do not address (i) the necessity to consider financial leverage, (ii) the sustainable growth DCF model, (iii) the risk premium model, or (iii) Staff's implementation of its DCF models. My position on these matters remains as described in my reply testimony.

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[6] Staff/2900, Muldoon/9 at 9-11.
[7] *Id*. at footnotes 16, 17, and 18.
[8] AWEC-CUB/200, Walters/5.

B. Considerations Regarding Staff's and AWEC-CUB's Recommendations

Q. Please summarize your view on the recommendations of the cost of capital witnesses in this proceeding.

A. Key recommendations of those providing a specific recommendation were shown in Figure 1 above. Both Staff and AWEC-CUB are recommending that PGE be allowed an ROE below the nationwide average allowed integrated electric utilities year-to-date (9.78% as of August 31, 2023).[9]

Additionally, Staff recommends an allowed ROE below PGE's currently allowed ROE of 9.5%,[10] while AWEC-CUB recommends using PGE's currently allowed ROE. However, since the Commission set PGE's currently allowed ROE, interest rates have increased as discussed in my reply testimony.[11] Relatedly, the parties' settlement of PGE's cost of debt reflects an increase over the cost PGE proposed in its opening testimony.[12]

Q. What market or industry developments indicate an increase in the cost of equity relative to PGE's last rate case?

A. As shown in Figure 2 below, the yield on A-rated utility bonds, as well as the 20-year Treasury bond yield, has increased.[13]

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[9] S&P Global Intelligence, "Past Rate Cases," downloaded September 2, 2023.

[10] *In the Matter of Pacificorp, dba Pacific Power, Application for Deferred Accounting of Costs Associated with the COVID-19 Public Health Emergency*, Docket UM 2063, Order No. 22-139 (May 9, 2022).

[11] PGE/2400, Villadsen-Liddle/7-10.

[12] Stipulating Parties/200, Muldoon – Gehrke – Mullins – Bieber – Chriss – Ferchland/7.

[13] In Figure 2, I have attempted to display the numbers for the month immediately prior to the event listed.

Figure 2:
A-rated Utility and 20-Year Treasury Bond Yields at Selected Dates[14]

	A-Rated Utility Bond Yield	20-Year Treasury Bond Yield
August, 2023(Surrebuttal)	5.60%	4.46%
June, 2023(Rebuttal)	5.34%	4.04%
January 2023(Filing)	5.00%	3.81%
March, 2022(UE 394 Decision)	3.88%	2.51%
June 2021 (UE 394 Filing)	3.04%	2.09%

Looking back a bit further, the last time 20-year treasury bond yields were in the range of 4.4% to 4.5% back in 2011, the average authorized ROE for electric utilities was 10.29%.[15]

As for Staff's comment that "State Commissions awarded natural gas utilities on average 10 bps higher ROE than like decisions for electric utilities,"[16] I note that Staff is referencing the average electric utility ROE as well as the average natural gas utility ROE, while (1) PGE is an integrated electric utility with the ROE being determined in a general rate case and (2) there were only seven decided gas utility cases in Q1, 2023 with an average allowed ROE of 9.64% and only three in Q2, 2023 with an average allowed ROE of 9.45%.[17]

Lastly, electric utilities' growth rates, as measured by expected growth in Earnings Per Share (EPS), have increased. For example, in Docket UE 394, I found electric utilities' expected growth to be 5.4%, whereas my direct testimony in this proceeding found it to be 5.7%.[18] All else equal, the cost of equity as measured by the DCF model increases with the growth rate. Hence, my opinion that the cost of equity has increased remains valid and a 9.8% ROE with a 50% equity share is not only reasonable but conservative.

[14] The Docket UE 394 initial filing was dated July 9, 2021, the settlement in Docket UE 394 was approved April 25, 2022, and Docket UE 416 was filed February 15, 2023.
[15] S&P Global Market Intelligence, "Major energy rate case decisions in US," March 31, 2023.
[16] Staff/2900, Muldoon/13 at 4-6.
[17] S&P Global Intelligence, "Major energy rate cases in the US," July 31, 2023.
[18] In Docket UE 394 I found an average growth rate for electric utilities of 5.4% (PGE/900, Jaramillo-Ferchland-Villadsen/51), in this case I found a growth rate of 5.7% (PGE/1000, Villadsen-Liddle/53). This is consistent with Staff's findings of a growth rate of 6.0% (Staff Screening) in Staff/2902, Muldoon/4.

C. Response to Staff's Rebuttal

Q. Staff states that it (i) "used two different multi-stage DCF models" and (ii) "relied on a CAPM and Gordon Growth model to validate the results obtained by its Three-State DCF models."[19] Do you dispute this testimony?

A. No. My concern is that when recommending an allowed ROE, Staff puts no weight on the CAPM, which is a fundamentally different model.

Q. If Staff puts no weight on the CAPM results, why are you concerned with the use of the geometric average as a measure of the market risk premium?

A. Because Staff uses the CAPM to "validate" the results from the DCF model, it is important that the CAPM measures the cost of equity as accurately as possible. That way, results that are out of line can be detected.

Q. Please summarize your concerns with the use of the geometric average for the purpose of determining the MRP that is used in the CAPM.

A. The cost of equity is a forward-looking concept, so the relevant MRP for cost of equity estimation is an estimate of the expected MRP and for that purpose, modern financial economics recommends the arithmetic average. As noted by Professors Brealey, Myers and Allen in their best-selling MBA textbook:

> *[T]he arithmetic average of the returns correctly measures the opportunity cost of capital for investments of similar risk to Big Oil stock [name of the example company]*

And

> *If the cost of capital is estimated from historical returns or risk premiums, use arithmetic averages, not compound annual rates of return.*[20]

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[19] Staff/2900, Muldoon/17.
[20] Brealey, Myers & Allen, *Principles of Corporate Finance* (12th Edition, 2017) 165.

Q. Have there been any developments in the finance literature since the Commission determined to use the geometric average?

A. Yes. The decisions Staff cites for the Commission's determination to use the geometric average to derive the market risk premium date back to 1987, 1993 and 1994.[21] Since then, financial economics has studied the merits of the arithmetic versus the geometric average for the purpose of measuring the expected return on the market and the market risk premium. Specifically, there are statistical issues that **could** cause the arithmetic average to be biased, but such issues are not present in the U.S. market.

In a 2005 paper Drs. Jacquier, A. Kane and A. Marcus examined the merits of weighing the arithmetic and geometric average for the purpose of estimating the MRP.[22] Specifically, the authors found that when the period over which the cost of equity is estimated is long compared to the period used to estimate the MRP, then one could appropriately place weight on the geometric averages using the formula in (1) below.[23] Staff measures the geometric average over 1926 to 2022 (95 years), while the allowed ROE is set for approximately 2-5 years, so that the period for which the cost of equity is set is much shorter than the period over which the MRP is measured. According to the 2005 paper, that means a very minimal weight can be assigned to the geometric average.

$$MRP = (1-H/T) \times Arithmetic\ MRP + (H/T) \times Geometric\ MRP \qquad (1)$$

Where H is the number of years during which the cost of equity will be in effect and T is the number of years used to estimate the MRP. Using Staff's horizon of 1926 to 2022, T = 96

[21] Staff/2900, Muldoon/9, footnotes 16, 17, and 18.
[22] Exhibit 4002C Eric Jacquier, Alex Kane & Alan Marcus, "Optimal estimation of the risk premium for the long run and asset allocation: A case of compounded estimation risk," 3 Journal of Financial Econometrics (2005) 37-55.
[23] *Id*.

years and assuming a new rate case every three years, the weight on the arithmetic average is 3/96 or 0.03, so very minimal weight is placed on the arithmetic average.

Professor Damodaran has argued that if the stock returns are serially correlated, as is the case in some countries, then some weight needs to be placed on the geometric average.[24] However, as shown in Kroll, the serial in the U.S. market is 0.0% for large stocks and 0.02% for small stocks. Thus, this again is a very small adjustment if any, and little weight needs to be placed on the geometric average.[25]

Importantly, these studies were performed after the Commission's policy was formalized in orders, so I would urge the Commission to consider the newer evidence. It is important because, as I showed in my reply testimony, the reliance on the arithmetic average would result in a CAPM estimate of the cost of equity in the range of 10.2%.[26] If Staff had found a CAPM estimate of 10.2%, it would indicate that the Three-Stage DCF models are estimating an unusually low cost of equity and therefore Staff would reasonably reconsider its low recommendation in favor of a higher number.

D. Response to AWEC-CUB Rebuttal Testimony

Q. What did AWEC-CUB cover in its rebuttal?

A. AWEC-CUB covered four topics: (i) the sustainable growth model, (ii) the risk premium model, (iii) CAPM, and (iv) Company risk. While I disagree with AWEC-CUB's rebuttal points, I shall only cover aspects of the CAPM and Company risk discussion here as I dealt

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[24] *See, e.g.*, Aswath Damodaran, "Equity Risk Premium (ERP): Determinants, Estimation and Implications - The 2012 Edition," Stern School of Business, NYU (March 2012), ERP2012 (nyu.edu)
[25] Exhibit 4001C Kroll, *Stocks, Bonds, Bills and Inflation (SBBI) Yearbook* (2023) 138.
[26] PGE/2400, Villadsen-Liddle/21.

with other aspects in my reply testimony.[27] As shown in Figure 2 above, the yield on A rated utility bonds as well as the 20-year Treasury bond yield has increased materially since the Commission set PGE's current ROE, which AWEC-CUB recommends maintaining.[28]

Q. AWEC-CUB states that "current" *Value Line* betas will be impacted by an anomalous historical event for approximately two more years and are not reflective of existing or expected conditions. As such, AWEC-CUB claims that historical betas provide a useful perspective.[29] How do you respond?

A. I do not disagree that the Covid-19 pandemic was anomalous. However, I disagree that the resolution to an anomalous event is to simply go back to a time before the event to obtain betas. The proper response, if AWEC-CUB finds the current Value Line betas are not proper measures of the systematic risk, is to (i) test for the abnormality in the underlying data and (ii) rely on statistical analyses to measure the current systematic risk. Simply substituting historical betas assumes that the future will be like the past and fails to consider changes in the electric industry.

Additionally, AWEC-CUB states that "historical betas provide a useful perspective." Yet, the AWEC-CUB's Opening Testimony relies on the historical betas in the same manner as its two current betas.[30] In other words, the historical betas are not just used to provide a perspective.

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[27] For a discussion of the sustainable growth model and why I disagree with AWEC-CUB regarding the sustainable growth model, please refer to PGE/2400, Villadsen-Liddle/16. As for my disagreement with the AWEC-CUB implementation of the risk premium model and the critique of my risk premium model, please see PGE/2400, Villadsen-Liddle/16-18.

[28] In Figure 2, I have attempted to display the numbers for the month immediately prior to the event listed.

[29] AWEC-CUB/200, Walters/6.

[30] *Id.*/100, Walters/51.

Q. AWEC-CUB states my critique that AWEC-CUB "failed to adhere to the instructions provided in the S&P Beta Generator Model Workbook are completely unfounded."[31] Please respond.

A. I believe this comment is based on a misunderstanding regarding my testimony. In this part of my reply testimony, I stated "regarding the S&P Global Intelligence betas, Capital IQ's instructions page shows that it is fundamental to unlever and relever the betas to take into account PGE' s capital structure and that the data relied upon to obtain the asset beta are market values."[32]

Hence, my comment pertains to the importance of financial leverage and especially the formula that the Unlevered Beta = Levered Beta / (1 + ((D/E) * (1 - T)) + P/E). This is the Hamada formula for unlevering betas. My reply testimony did not discuss the Vasicek adjustment.

Q. AWEC-CUB critiques your discussion of PGE's smaller size relative to the proxy companies. Please respond.

A. First, I made no explicit adjustment to the recommended ROE based on the size of PGE. Second, Kroll provides annual measures of the size premium, which are relied upon by, for example the Federal Energy Regulatory Commission (FERC),[33] so I disagree that such premia are not appropriate. FERC Order 569, ¶301 explicitly rejected relying on the study AWEC-CUB quotes.[34]

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[31] AWEC-CUB/200, Walters/6.
[32] PGE/2400, Villadsen-Liddle/19.
[33] See, for example, FERC Opinion 569, ¶295-303.
[34] AWEC-CUB/200, Walters/8, footnote 3.

Q. Does the fact that you have not addressed all issues in other party's testimony indicate that you agree?

A. No, it does not.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
4001C	Kroll 2023 SBBI Yearbook, 128
4002C	E. Jacquier, A. Kane and A. Marcus (2005), "Optimal estimation of the risk premium for the long run and asset allocation: A case of compounded estimation risk," *Journal of Financial Econometrics* 3, 37-55.
4003C	S&P Global Intelligence as of September 2, 2023

Exhibit 4001 contains confidential information and is subject to Modified General Protective Order 23-039.

Exhibit 4002 contains confidential information and is subject to Modified General Protective Order 23-039.

Exhibit 4003 contains confidential information and is subject to Modified General Protective Order 23-039.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 416

Income Qualified Bill Discount Program (IQBD)

PORTLAND GENERAL ELECTRIC COMPANY

Surrebuttal Testimony of

Sunny Radcliffe
Robert Macfarlane

September 11, 2023

Table of Contents

I. Introduction

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

A. My name is Sunny Radcliffe. I am the Director of Government Affairs for PGE. My qualifications appear at the end of this testimony.

My name is Robert Macfarlane. I am Manager of Pricing and Tariffs at Portland General Electric Company (PGE). My qualifications are included in PGE Exhibit 1200.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to respond to rebuttal testimony from the Staff of the Oregon Public Utility Commission (Staff), the Citizens' Utility Board (CUB), the Alliance for Western Energy Customers (AWEC), as well as the joint testimony from Community Energy Project and Community Action Partnership of Oregon (CEP-CAPO) concerning proposed changes to the structure of PGE's Income Qualified Bill Discount Program (IQBD). We also discuss the proposal for a Low Income Needs Assessment (LINA) study.

Q. How is the remainder of your testimony organized?

A. After this introduction, we have three sections:

- Section II: Current and Proposed IQBD Structure and Levels
- Section III: Low Income Needs Assessment (LINA)
- Section IV: Qualifications

Q. Please provide a summary of your testimony.

A. PGE details our plans to submit tariff sheets revising the IQBD program to provide higher discounts for residential customers with the lowest incomes. This increase goes beyond our initial proposal in reply testimony, responding to parties' advocacy for increased tiers and discount levels. PGE also outlines our commitment to conduct a Low Income Needs

Assessment (LINA) next year, engaging PGE's Community Benefits and Impact Advisory Group (CBIAG) and other stakeholders in the process. On both of these topics, we respond to rebuttal testimony submitted by Staff, CUB, CEP-CAPO, and AWEC.

Q. Please describe PGE's current programs to help customers address energy burden.

A. PGE offers discounts and incentives targeted to assist customers in need. Some examples include: the income-qualified bill discount program, our new smart thermostat program (discount on new smart thermostat via PGE's marketplace), peak time rebates, elevated incentives in our transportation electrification programs and community solar program, and back-up generators for those with medical certificates who reside in high fire risk zones. We also work to connect customers with community action agencies and the Energy Trust of Oregon for weatherization and energy efficiency support.

II. Current and Proposed IQBD Structure and Levels

A. Current IQBD Structure and Levels

Q. Please describe PGE's current IQBD program.

A. PGE's current IQBD program offers three levels of bill discounts to customers whose gross income is below 60% of state median income (SMI):

- Tier 1: 0-30% SMI – 25% discount
- Tier 2: 31-45% SMI – 20% discount
- Tier 3: 46-60% SMI – 15% discount

In addition, customers who live alone and work full-time earning the Oregon minimum hourly wage for the Portland Metro region[1] qualify for a 15% discount even in years when household earnings could be higher than the Oregon Department of Housing and Community Services (OHCS) income guidelines.

Since PGE's program launch in April 2022, over 70,000 customers have been enrolled in the IQBD with only a small number of enrollees that have moved or otherwise unenrolled. Currently, over 62,000 customers are actively enrolled in IQBD and receive discounts on their bills. This is just over half of the total 120,000 customers that PGE estimates will enroll in the program by the end of 2024. As part of the IQBD development effort, PGE researched enrollment levels for bill assistance programs in other states. We estimate that of the roughly 160,000 residential customers who may be eligible for IQBD, about one-quarter may never enroll so we forecast program maturity to be 120,000 enrolled customers. This estimate does

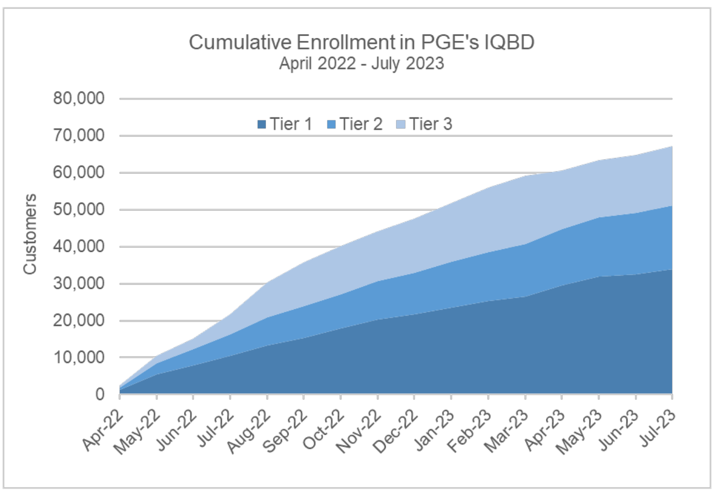
[1] From July 1, 2023, through June 30, 2024, the Portland metro minimum wage is $15.45 per hour. A person working full time could earn $32,136 per year, compared to the OHCS income guideline for single-person households earning 60% SMI, $31,266.

not preclude PGE from attempting to enroll all eligible households but helps us develop potentially more accurate cost forecasts.

In 2022, bill discounts totaled just over $4 million provided to customers under this program and in 2023, PGE forecasts the bill discounts will total about $23 million. If no adjustments are made to the discount tiers or level, PGE forecasts bill discounts will increase to $40-$50 million in 2024 and over $50 million in 2025.

The graph below shows cumulative total enrollments[2] by month and IQBD tier since program launch in April 2022.

Figure 1
Cumulative Enrollment in PGE's IQBD



Q. Did PGE consider affordability when developing the existing IQBD program?

A. Yes. In designing the initial discount tiers and rate levels, PGE's aim was to reduce bills for those most in need while managing the cost impacts of the program on other customers.

Q. Please describe enrollment in the IQBD program?

A. A key design element of PGE's discount program is its accessibility to eligible customers. Customers are able to quickly enroll online by completing a simple form or via a phone call

[2] This graph reflects all enrollments in a given month, including those who have since moved out of PGE's service territory or otherwise unenrolled.

with a PGE representative. Beginning in June 2022, PGE was able to automatically enroll in our IQBD program customers who received assistance from the Oregon Energy Assistance Program (OEAP) or the federal Low Income Home Energy Assistance Program (LIHEAP) because eligibility must be documented as part of qualifying for these programs.

Customers who have not received state or federal bill assistance can enroll directly with PGE, via an online form or via our Customer Service Advisors, with a self-attestation of their eligibility. To date, approximately one-quarter of enrollments have been agency-qualified and the remaining three-quarters are split fairly evenly between enrollment via a phone call with a PGE representative and online enrollments.

Q. Please describe PGE's outreach efforts for the IQBD program.

A. In the first year of the program, outreach focused on customers who had received state or federal energy assistance at some point in the past as they were likely to be eligible for IQBD and enrollment levels were higher than expected. In 2023, PGE has provided outreach to many of our communities to encourage awareness of, and enrollment in, our IQBD program. For example, we have attended resource fairs and other events sponsored by community partners, such as Good in the Hood, El Grito Portland, Juneteenth celebrations, Pride events, among others. PGE has also shared IQBD information with Community Benefit Organizations directly and promoted the program at community workshops on emergency preparedness during wildfire and heat events. Currently, PGE is preparing for a large-scale mail and email campaign in advance of high bill season, and recently relocated the IQBD notification to the portlandgeneral.com homepage, with the goal of reaching all customers.

B. Response to Parties Proposed Structure and PGE's Proposal

Q. Did the parties suggest revisions for PGE's IQBD program in their rebuttal testimony?

A. Yes. There were three proposals made in rebuttal testimony by parties to alter PGE's IQBD program summarized as follows:

- CUB recommends a 4-tier structure where the largest discount is 60% for 0-15% SMI and the remaining discount levels remain unchanged.
- CEP-CAPO jointly propose a 5-tier structure where the top discount is 90% for 0-5% SMI, followed by 75% for 6-15% SMI, 40% for 16-30% SMI and unchanged levels for the remaining two tiers.
- Staff also proposes a similar overarching 5-tier structure to that of CEP-CAPO where the top discount reaches up to 90% within 0-5% SMI and up to 70% within 6-15% SMI; however, Staff's design includes intra-tier discount ramps within these tiers. These ramps effectively create an additional 14 tiers at increments of one percentage point of SMI, for a total of 19 tiers. The remaining three discount levels remain unchanged.

Table 1 below details the current IQBD program structure and the three proposals from parties.

Table 1.
IQBD Proposals

<table>
<tr><th>SMI Bins</th><th>Current Program</th><th>CUB</th><th>CEP-CAPO</th><th>Staff</th></tr>
<tr><td>0-5%</td><td rowspan="3">25%</td><td rowspan="2">60%</td><td>90%</td><td>73-90%, depending on SMI %</td></tr>
<tr><td>6-15%</td><td>75%</td><td>40-70%, depending on SMI %</td></tr>
<tr><td>16-30%</td><td>25%</td><td>40%</td><td>25%</td></tr>
<tr><td>31-45%</td><td>20%</td><td>20%</td><td>20%</td><td>20%</td></tr>
<tr><td>46-60%</td><td>15%</td><td>15%</td><td>15%</td><td>15%</td></tr>
</table>

Q. Did any party offer a proposal for altering PGE's IQBD program in opening testimony?

A. No. None of the parties brought forth a proposal in their opening testimony to alter PGE's IQBD program. CEP and CAPO offered in-depth testimony on energy justice and low-income related issues but did not provide a specific proposal for altering PGE's IQBD program. While CUB briefly touched on low-income issues as they relate to the cap on Schedule 118, they did not offer that the IQBD structure and levels be changed, and Staff also provided thorough testimony regarding energy justice and low-income issues without any proposal specific to PGE's IQBD program.

Q. Did PGE propose changes to its IQBD program in this rate case?

A. Yes. We did not submit an advice filing to change the program tariff with our opening testimony in February. At that time, we did not have adequate data to evaluate the needs and participation level since the program had been offered for less than a year. In our reply testimony, with more data available, we indicated that we would be updating our IQBD program to allow for a 40% discount for the lowest income levels.[3]

Q. What are Staff and CEP-CAPO's concerns regarding the existing structure and PGE's proposed modification to add a fourth tier with a 40% discount?

A. Staff and CEP-CAPO assert that neither PGE's current IQBD tiers nor our proposed additional tier will sufficiently address energy burden among customers with the lowest incomes. In their analyses of energy burden among IQBD participants who also received energy assistance funds, along with research into peer utilities' low-income needs assessment (LINAs), they argue that the discount offered to the very lowest tier should be much higher, closer to 90-95%.

[3] PGE/2600, Macfarlane-Pleasant/11-12 at 20-3.

They also advocate for greater analysis of participant energy burden using income and household data collected at IQBD enrollment.

Q. Please describe the specific modifications Staff is suggesting to the existing IQBD structure?

A. Staff recommends expanding the IQBD offering to a complex 19-tier program. This is because they recommend that PGE move from a 3-tier structure to a purported 5-tier structure. However, two new tiers are carved out of the current Tier 1 and are further broken out into sub-tiers that increment every percentage point of SMI. This effectively creates a 19-tier program. Furthermore, Staff proposes discounts rates up to 90% and up to 70% for the two new tiers where discount rates increase in increments of 3.5% for each deduction in % SMI. The discount rates for participants with incomes above 15% SMI would remain unchanged.

Staff's stated reason for such narrow tiers among the lowest income households is to help mitigate "unintended programmatic inequities" and increase program cost efficiency by not overpaying for some customers within a single tier and better align with the energy burden distribution.

Staff estimates these changes will result in an annual cost of \$62-\$70 million in 2025, assuming the program enrollment reaches maturity by the end of 2024.[4] PGE estimates costs will be closer to the \$70-\$80 million range.

Q. Please describe CEP-CAPO's jointly recommended adjustments to PGE's IQBD program?

A. In their joint rebuttal testimony, CEP-CAPO recommend moving to a 5-tier structure with two additional tiers carved out of current Tier 1. They suggest a discount of 90% for

[4] Staff/3100, Scala/21-22 at 20-2.

households with income up to 5% SMI and 75% for those with income between 6-15% SMI. Additionally, CEP-CAPO recommend increasing the discount for those with income between 16-30% SMI from 25% to 40%. Their goal with these adjustments is to keep the average energy bill for customers with electric heat below 6% of their household income, after absorbing expected rate increases in 2024.

CEP-CAPO estimates these changes will result in an annual cost of $85 million in 2025, again, assuming the program enrollment reaches maturity by the end of 2024. PGE's modeling efforts indicate costs would be slightly higher, likely over $90 million in 2025.

CEP-CAPO also recommend that PGE modify Schedule 18 to reflect IQBD eligibility for single-family households earning the Portland Metro minimum wage without reference to a specific dollar value. This modification would mitigate the need for future tariff adjustments every time there are changes to the OHCS income guidelines or the Portland Metro minimum wage.

Q. What modifications did CUB propose?

A. CUB recommends a 4-tier structure with an additional tier carved out of Tier 1; 60% discount for 0-15% SMI; goal is to "alleviate impacts from this [GRC] while the larger investigation into IQBD programs can move forward."[5]

CUB estimates these changes will result in an annual cost of $55 million in 2025 (presumed to be the first year of program maturity; does not include assumptions about price increases after 2026). PGE estimates costs will be $65-$75 million.

[5] CUB/500, Gehrke/13-14 at 17-1.

Q. Currently, what percentage of PGE's IQBD participants are within the 0-5% SMI range?

A. Using income and household size data provided in customer eligibility self-attestations and by OHCS monthly updates for automatic enrollment of energy assistance recipients, PGE calculates that roughly 13% of current IQBD participants are within the 0-5% SMI range.

Q. Did any other parties provide testimony concerning the structure or discount amounts for the IQBD program?

A. Yes, AWEC submitted testimony stating that they do not support a requirement that customer bills not exceed 6% of household incomes (energy burden) cap due to infeasibility, imprecision, and further cost shifts to non-residential customer. AWEC states that the parties' proposals would result in substantial additional costs borne by customers that do not qualify as 'energy burdened' or 'low income' and specifically questions how Staff can testify that it 'represents the interests of all customer classes' when "its testimony does not address the potential impacts of requiring Oregon's businesses to assume substantially greater than their share of costs."[6]

AWEC also points out that enforcing a cap whereby the total energy burden of residential households is limited to 6% of their household income was rejected by the Oregon Legislature in their most recent session[7] and furthermore, such a cap would require "a level of information precision that likely does not exists. Even if PGE has access to customer's income through tax returns or other means, that income fluctuates year-to year, as does energy consumption."[8]

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[6] AWEC/700, Kauffman/15 at 12-14.
[7] *Id.*/21 at 10-11 referencing HB 3459.
[8] *Id.*/20 at 13-15.

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

A. As we contemplate the concerns posited by AWEC, we find ourselves agreeing with AWEC's statement that it is "not aware of a single such entity that has the types of energy burden and disconnection restrictions the parties advocate for here."[9] PGE thinks that AWEC's concerns that the proposals by Staff, CUB, and CEP-CAPO "may lead to severe unintended consequences, including 'unprecedented' arrearage balances for PGE and the closure of major employers in the region"[10] are valid and we question CUB and Staff's lack of explanation to address these issues when putting forward their proposals.

Q. Does PGE support the parties' proposals?

A. No. PGE has significant concerns about both the levels and complexity associated with parties' proposals. Since the proposals were not introduced until parties' reply testimony, PGE and other parties lacked an opportunity for meaningful review, including the ability for other parties to submit testimony in response. Due to the introduction of the proposal at this late-stage, more data and time is needed to evaluate. PGE is, however, supportive of updating its IQBD program and making meaningful modifications to address some of the program's most energy-burdened participants.

Q. What concerns does PGE have with the program modifications proposed by Staff, CEP-CAPO, and CUB?

A. While PGE is sympathetic to the arguments made by Staff and CEP-CAPO, we cannot support their proposed discount levels because of the overall cost it would place on other customers without additional data and experience to support their proposals. In the next section we

[9] *Supra*. /16 at 5-6.
[10] *Id*./16-17 at 22-2.

discuss our commitment to facilitate a LINA that will help inform the future evolution of IQBD.

We also appreciate the effort at cost efficiency reflected in Staff's tier precision, but implementation and management of what would effectively be 19 tiers would be administratively burdensome for PGE and likely confusing for customers. PGE's IQBD application asks customers to provide their "average gross annual income [for] your household"[11] and contact PGE with notable updates to their income or household size information. This does not align with the precision of discount tiers that differ by 1% of SMI, or about $680 annually.

CUB's proposal is similar to the 4-tier structure proposed by PGE in reply testimony; however, CUB's recommends a 60% discount for households earning 0-15% SMI compared to a 40% discount put forth by PGE.

Q. Does PGE agree with the cost estimates provided by the parties for their proposed revisions to the IQBD structure?

A. A range of cost estimates for each of these proposals are shown in Table 2, including the estimate(s) provided by parties in testimony and PGE's cost estimates reflecting a modeling correction to the forecasting workbook shared with parties and an adjustment to the distribution of participants across tiers.

[11] See PGE Income-Qualified Bill Discount Application on portlandgeneral.com.

Table 2.
IQBD Cost Estimates for Proposed Structures

<table>
<tr><th>SMI Bins</th><th>Current Program</th><th>PGE Proposal</th><th>CUB</th><th>Staff (low)</th><th>Staff (high)</th><th>CEP-CAPO</th></tr>
<tr><td>0-5%</td><td rowspan="3">25%</td><td>60%</td><td rowspan="2">60%</td><td>70%</td><td>90%</td><td>90%</td></tr>
<tr><td>6-15%</td><td>40%</td><td>40%</td><td>70%</td><td>75%</td></tr>
<tr><td>16-30%</td><td>25%</td><td>25%</td><td>25%</td><td>25%</td><td>40%</td></tr>
<tr><td>31-45%</td><td>20%</td><td>20%</td><td>20%</td><td>20%</td><td>20%</td><td>20%</td></tr>
<tr><td>46-60%</td><td>15%</td><td>15%</td><td>15%</td><td>15%</td><td>15%</td><td>15%</td></tr>
<tr><td>Parties' 2025 estimate</td><td></td><td></td><td>$67*</td><td>$62</td><td>$70</td><td>$85</td></tr>
<tr><td>PGE’s 2025 estimate[12]</td><td>$53</td><td>$66</td><td>$70</td><td>$69</td><td>$81</td><td>$94</td></tr>
</table>

*CUB provided a 2024 cost estimate in their rebuttal testimony ($55 million). PGE estimates the 2025 equivalent for their estimate is $67 million.

Q. Are there additional reasons that PGE does not want to adopt the Parties’ proposed modifications to the Company’s IQBD program at this time?

A. Yes. While PGE is pleased with the engagement and enrollment levels it has achieved so far in the IQBD program, it is still a relatively new program that has been in place for a year and a half. As previously mentioned, the program is not yet at a stable level of enrollment and as Table 2 shows, there are uncertainties on the cost-impact for the program under the parties’ various proposals. PGE is concerned with rolling out significant modifications to the program prior to reaching a stable enrollment level.

It also became clear in conversations during this proceeding that Staff and CEP-CAPO strongly desire that PGE conduct a low income needs assessment that could provide insights on how the IQBD program should transition in the future. While we will discuss the low income needs assessment study in the next portion of our testimony, it would be premature to adopt major changes to the IQBD program in the interim.

[12] PGE’s 2025 program cost estimates assume 120,000 participants throughout the year, that future enrollments distribute across the discount tiers similar to past enrollments and estimate price increases for both years.

Q. In response to parties' concerns, does PGE have any further modifications to their IQBD program that have not been shared in reply testimony?

A. Yes, PGE has a new proposal that will address some of parties' stated concerns, namely insufficiently low discount levels for those in the 0-5% SMI bin. In reply testimony, PGE proposed carving an additional tier out of Tier 1 (currently available to households earning 0-30% SMI) and offering a 40% discount for households earning 0-15% SMI. The remaining discounts would stay the same. In PGE's regular IQBD outreach meetings, Staff, and stakeholders recommended PGE offer a deeper discount similar to peer utilities in Oregon and our proposal centered on alignment with PacifiCorp and Northwest Natural, the latter of which we share customers with. The deepest discount offered by these utilities is 40%.

Staff and CEP-CAPO advocate for a more nuanced discount structure that allows for deeper discounts for smaller subsets of the highest burdened customers while still providing more modest discounts for less-burdened households. PGE's proposed modifications would yield the following overall discount structure, including a new tier number scheme:

- Tier 0: 0-5% SMI – 60% discount
- Tier 1: 6-15% SMI – 40% discount
- Tier 2: 16-30% SMI – 25% discount
- Tier 3: 31-45% SMI – 20% discount
- Tier 4: 46-60% SMI – 15% discount

The updated IQBD program structure is expected to cost roughly $50-60 million in 2024, assuming program maturity is reached at the end of that year, and $60-70 million in 2025.

III. Low Income Needs Assessment (LINA)

Q. Please summarize parties' recommendations with regard to a LINA for PGE's service territory?

A. Staff and CEP-CAPO previously recommended that PGE consider conducting a LINA to better understand the "extent and distribution of energy poverty and energy insecurity,"[13] and to inform the evolution of PGE's IQBD offering. In rebuttal testimony, Staff, CEP-CAPO, and CUB focused their LINA recommendations to specify that PGE conduct an assessment by the end of 2024 and collaborate with Staff and stakeholders on project scope, objectives, and key deliverables. They also advocate for results to be made public. Staff uniquely indicates that the cost associated with a LINA could be deferred through UM 2219, subject to a prudence review, but not dependent on an earnings test.

Staff and CEP-CAPO note that Avista, Cascade, and Northwest Natural have conducted LINAs of their Oregon service territories. As Staff notes, energy burden assessments are the specific analysis that was undertaken by Avista and Cascade to inform their discount offerings.[14] Despite that fact, the term LINA has been used interchangeably in UE 416 and other regulatory proceedings.

Q. What would PGE expect to learn from a LINA?

A. PGE would target a scope that yields greater accuracy about the extent and distribution of energy burden among our customers to inform future evolutions of IQBD, rate design, or other offerings that could help lessen energy burden. PGE is also interested in information related to utility measurements of energy burden among dual-fuel households.

[13] Staff/600, Scala/40 at 19-20.
[14] Staff/3100, Scala/12 at 13 and *Id.*/17 at 9.

In reply testimony, PGE agreed to consider an assessment and has been actively researching vendors, educating ourselves on scope and detail typically delivered, as well as the duration and cost a PGE study might require.

Q. What is PGE's response to Parties' recommendations and related proposal?

A. PGE agrees to facilitate a LINA in 2024 that would be implemented by a third-party contractor. PGE also agrees to work with our Community Benefits and Impacts Advisory Group to develop the scope, approach, and deliverables, and consider the perspectives of additional stakeholders, with the understanding that PGE is responsible for the final determination. PGE expects results to yield actionable results for rate design, customer offerings, and tariffs and that costs would not exceed $250,000. Additionally, PGE seeks assurance, as indicated in Staff testimony, that assessment costs could be deferred through UM 2219 and recovered via Schedule 118 following a prudence review but absent an earnings test.[15]

Q. How does PGE intend to conduct a LINA?

A. PGE intends to facilitate a LINA with a third-party vendor with structure and overall scope informed by PGE and our CBIAG as described above. To strengthen our commitment to creating a cleaner and more equitable future in Oregon, PGE convened its CBIAG in accordance with Oregon House Bill 2021. In partnership with our third-party facilitator, Espousal Strategies LLC, the CBIAG aims to build understanding of clean energy goals and engage with community members as collaborators in developing more equitable strategies. The CBIAG is convened monthly and creates an inclusive forum that prioritizes feedback

[15] Staff/3100 Scala/14 at 12-18.

from members within our service area, including low-income and other environmental justice communities.

IV. Qualifications

Q. Sunny Radcliffe, please summarize your qualifications.

A. I have served as PGE's Director of Government Affairs since January 2010. My responsibilities include public policy development, analysis and advocacy relating to a variety of government entities, including the Oregon Legislature and the U.S. Congress. I hold a Bachelor of Arts degree in political science from the University of Washington. I also hold a Juris Doctor, with a certificate in Environment and Natural Resources, from the Northwestern School of Law of Lewis and Clark College. I have been a member of the Oregon State Bar since 1996.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 416

Pricing

PORTLAND GENERAL ELECTRIC COMPANY

Surrebuttal Testimony of

Robert Macfarlane
Christopher Pleasant

September 11, 2023

I. Introduction

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

A. My name is Robert Macfarlane. I am the Manager of Pricing and Tariffs for PGE. My qualifications were previously provided in Direct Testimony, PGE Exhibit 1200.

My name is Christopher Pleasant. I am a Senior Regulatory Analyst in Pricing and Tariffs for PGE. My qualifications were previously provided in Direct Testimony, PGE Exhibit 1300.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to respond to the rebuttal testimony provided by the Public Utility Commission of Oregon (OPUC or Commission) Staff (Staff), the Citizens' Utility Board of Oregon (CUB), the Alliance of Western Energy Consumers (AWEC), Natural Resources Defense Council (NRDC), Northwest Energy Coalition (NWEC), and Walmart Inc. (Walmart) (collectively, Parties).

Q. How is the remainder of your testimony organized?

A. The Parties and PGE have resolved the pricing issues other than decoupling with a partial settlement that we will be filing with the Commission.

Section II summarizes the Parties' position on decoupling: Staff continues to oppose decoupling; NRDC/NWEC continues to support it; and CUB will support decoupling only if it is not paired with a revision to the Power Cost Adjustment Mechanism (PCAM). PGE reiterates that it would only support moving forward with decoupling in concert with a revised PCAM.

II. Revenue Decoupling

Q. Please summarize Parties' positions on PGE's revenue decoupling proposal made in opening testimonies.

A. In our opening testimony, PGE proposed restoring the decoupling mechanism if, and only if, our proposed changes to the PCAM were adopted. We proposed a sales normalization adjustment (SNA) mechanism for Schedules 7, 32, and 38 that compares actual weather-adjusted distribution, transmission, and fixed generation revenues that are collected on a volumetric basis with those that would be collected with a fixed per-customer charge and a 3% soft cap on collections and refunds to mitigate the year-to-year price fluctuations on customer bills. Any amounts that exceed the 3% soft cap will carry forward in the subsequent year (or years) into a balancing account for refund or recovery.

In opening testimony, Staff opposed restoration of the decoupling mechanism, arguing that decoupling largely passes short-term business risk from shareholders to rate payers. Staff also argued that the mechanism is not necessary to promote energy efficiency (EE) and other environmental goals because, in Oregon, EE measures are administered by the Energy Trust of Oregon (ETO). In contrast, in opening testimony, NRDC/NWEC supported restoring the decoupling mechanism in the manner described by PGE and asserted that decoupling is needed to promote cost-effective EE, which is in the public interest. No other parties filed opening testimony on this topic.

Q. Which parties submitted rebuttal testimony regarding revenue decoupling?

A. Staff, CUB, and NRDC/NWEC submitted rebuttal testimony regarding revenue decoupling.

Q. Did Staff's opposition to revenue decoupling change in their rebuttal testimony?

A. No. Staff continues to oppose reestablishment of a decoupling mechanism. Staff continues to argue that decoupling largely passes short-term business risk from shareholders to ratepayers and is not necessary to promote EE and other environmental goals.[1] Staff additionally does not support PGE's PCAM proposal which, for PGE, is a prerequisite to reestablishing the mechanism. Staff also responded to NRDC/NWEC's opening testimony arguing that NRDC and NWEC did not demonstrate a causal link between EE and decoupling, but signal that they are open to rediscussing the issue if EE investment dramatically falls. Staff also argues that ETO is well established and does not rely on residential EE referrals from PGE.[2]

Q. Is Staff's representation that ETO does not rely on referrals from PGE a true representation of the relationship between ETO and PGE?

A. No. To imply that PGE does not provide referrals to ETO is an inaccurate representation of the relationship. The purpose listed in PGE's Schedule 110 is:

> To fund Company activities associated with enabling Customers to achieve energy efficiency including, but not limited to project facilitation, technical assistance, education and assistance to support programs administered by the Energy Trust of Oregon (ETO).

PGE continually supports EE funding requests from ETO through PGE's Schedule 109. In addition, PGE promotes EE through its website, bill inserts, and customer newsletters. On an ongoing basis, PGE conducts targeted commercial and residential marketing campaigns encouraging customers to participate in ETO programs. In partnership with ETO, PGE works directly with small and mid-size business customers to help them identify and implement EE projects. Furthermore, PGE works closely with ETO to implement future estimates of EE in

[1] Staff/3300, Stevens/41-42.
[2] Staff/3300, Stevens/43 at 15-19.

PGE's Integrated Resource Plans. Finally, PGE has account representatives for large customers that help facilitate discussions with large customers related to a variety of activities, including EE.

Q. Did NRDC/NWEC's position supporting PGE's decoupling proposal change in their rebuttal testimony?

A. No. NRDC/NWEC continue to recommend that the Commission restore revenue decoupling in the manner described by PGE in our opening testimony.

Q. PGE's position is that adoption of a decoupling mechanism must also include adoption of PGE's PCAM proposal. Do NRDC/NWEC agree?

A. Yes. NRDC/NWEC agree that adoption of a decoupling mechanism should only occur upon adoption of PCAM reform, stating:

> I agree that increasingly extreme weather exposes PGE to greater wholesale market volatility and to revenue losses that decoupling without PCAM reform could exacerbate. On balance, given both the increasing importance of these markets to reliable decarbonization of the electricity sector and the urgent need to reinstitute revenue decoupling, I agree that the Commission should reconsider the current PCAM risk allocation mechanism.[3]

Q. What is CUB's recommendation regarding PGE's testimony on revenue decoupling?

A. CUB does not oppose reinstituting decoupling with an SNA, including with a 3% soft cap in the manner as proposed by PGE. CUB views the shift in risk onto customers from decoupling as not very large and may be outweighed by the benefits of decoupling. CUB observes that having a decoupling mechanism has minimized regulatory conflicts over the load forecast in general rate cases because decoupled utilities' net income is not affected by changes in sales volumes versus estimated sales volumes. CUB further states that the benefits of decoupling

[3] NRDC-NWEC/200, Cavanagh/10-11 at 18-3.

have been reduced in Oregon because utilities no longer administer the majority of EE programs, a role now played by the ETO.[4]

Q. Does PGE agree with CUB's statement that the benefits of decoupling have been reduced in Oregon because ETO administers EE?

A. No. We do not agree with CUB's statement. PGE has a long history of ample funding and program delivery of EE programs in our service territory prior to the existence of the ETO. EE is an important tool for PGE to help meet our required clean energy goals in the coming years. In addition to providing funding, PGE has a significant role in customer adoption of EE as we already discussed.

Q. Does CUB support PGE's decoupling proposal if the Commission also approves changes to PGE's PCAM mechanism?

A. CUB opposes the use of decoupling as leverage for PCAM reform. They argue that it is the equivalent of PGE shifting the risk of fixed cost recovery from shareholders to customers but only if Parties agree that PGE can shift most of the risk of variable cost recovery from shareholders to customers through PCAM reform.[5]

Q. How does PGE respond to CUB's rationale that linking a revenue decoupling mechanism with PCAM reform is not appropriate?

A. As discussed in detail in PGE's PCAM proposal,[6] PGE's current risk profile is greater than that of its peers, and all regulatory mechanisms should be looked at holistically. Regulatory mechanisms such as decoupling or PCAM do not operate in isolation, and therefore, must be compatible with other key regulatory tools, most importantly the fuel and

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[4] CUB/400, Jenks/35 at 1-6.
[5] CUB/400, Jenks/35-36 at 20-4.
[6] PGE/3200.

power cost recovery mechanisms. Absent PCAM reform, we do not support the adoption of revenue decoupling. The combination of PGE's current PCAM mechanism and revenue decoupling increases PGE's risk profile[7] and its ability to decarbonize while maintaining reliable electric service for customers.[8]

Q. Has PGE's position on moving forward with a decoupling mechanism only with appropriate PCAM reform changed since its reply testimony?

A. No. For revenue decoupling to be viable and effective in achieving desired policy objectives, PCAM reform is first necessary to ensure a fair and reasonable balance of benefits and risk between the PGE and customers.

Q. Does this conclude your testimony?

A. Yes.

[7] PGE/1300, Macfarlane – Pleasant/39-40.
[8] PGE/2600, Macfarlane – Pleasant/18-19 at 7-2.