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February 7, 2022

VIA ELECTRONIC FILING

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

Re: UE 394 – *In re Portland General Electric Company, Request for a General Rate Revision.*

Attention Filing Center:

Attached for filing in the above-referenced docket is Portland General Electric Company's Prehearing Brief.

Please contact this office with any questions.

Sincerely,

Katherine McDowell

Attachment

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 394

In the Matter of

PORTLAND GENERAL ELECTRIC COMPANY,

Request for a General Rate Revision.

PORTLAND GENERAL ELECTRIC COMPANY'S PREHEARING BRIEF

February 7, 2022

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I. INTRODUCTION

Portland General Electric Company (PGE or Company) filed its last general rate case (GRC), Docket UE 335, in February 2018.[1] From that GRC through the end of the 2022 test period in this case, inflation is expected to increase by over 12 percent.[2] Despite rising costs, PGE has kept its base rates steady for several years and worked hard to moderate its initial rate request in this case of a $58.9 million increase, or 2.9 percent overall (excluding net variable power costs (NVPC)).[3]

After four stipulations, the September 2021 load forecast update, and the removal of the Faraday Repowering project from revenue requirement effective May 9, 2022, PGE has reduced its non-NVPC rate request to $10 million, or approximately 0.5 percent overall.[4] All parties have agreed that this is a reasonable revenue requirement increase, subject only to a potential $3 million reduction if the Commission adopts Staff's proposed wildfire mitigation cost recovery mechanism[5]—which, as PGE discusses below, would not comply with Senate Bill 762 (SB 762).[6]

There are four main issues that remain controverted in this case: cost recovery for the Faraday Repowering project, treatment of wildfire mitigation costs, revising PGE's Level III mechanism to better respond to the increasing frequency, variability, and magnitude of major outage events, and whether and how to address the three specific deferrals parties brought into this case. On these remaining issues, PGE respectfully requests that the Commission rule as follows:

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[1] *In re Portland Gen. Elec. Co., Request for a Gen. Rate Revision*, Docket UE 335, Order No. 18-464 (Dec. 14, 2018), modified, Order No. 19-129 (Apr. 12, 2019).
[2] Docket UE 394, Joint Testimony in Support of Third Partial Stipulation, Stipulating Parties/300, Muldoon-Gehrke-Mullins-Bieber-Chriss-Steele-Ferchland/4 (Jan. 18, 2022).
[3] Stipulating Parties/300, Muldoon-Gehrke-Mullins-Bieber-Chriss-Steele-Ferchland/4.
[4] Stipulating Parties/300, Muldoon-Gehrke-Mullins-Bieber-Chriss-Steele-Ferchland/4. This amount excludes the forecast for Oregon Corporate Activity Tax (OCAT) of $8.4 million, which will move from a supplemental schedule to base rates and, therefore, does not constitute an actual increase in revenue.
[5] *Id*. at 5.
[6] SB 762 (2021). Available at: https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/SB762/Enrolled.

- Faraday: Open Phase II of Docket UE 394 to allow parties to evaluate the prudence of the Faraday Repowering project and permit PGE to incorporate the prudently incurred repowering costs for this non-emitting, capacity resource into rates once the project is placed in service in the fourth quarter of 2022.
- Wildfire Costs: Reject Staff's proposal to hold back $3 million in wildfire mitigation and vegetation management costs, the prudence of which no party has questioned. Allow PGE to defer in Docket UM 2019 the incremental wildfire mitigation costs associated with implementation of PGE's 2022 Wildfire Mitigation Plan, described in surrebuttal testimony, for recovery at a later date under the new cost recovery mechanism described below.
- Wildfire Cost Recovery Mechanism: Approve proposed Schedule 151, a new cost recovery mechanism applicable to incremental wildfire mitigation costs that would allow dollar-for-dollar recovery of those costs through an automatic adjustment clause (AAC), consistent with the cost recovery language of SB 762.
- Level III Outage Mechanism: Approve PGE's proposed revisions to the Level III outage mechanism to allow balances to go negative and apply sharing, which complies with the Commission's direction from prior cases.
- Deferrals: Decline to consider the Boardman, 2020 Wildfire, and 2021 Ice Storm deferrals in this docket and instead consider them in the specific dockets already opened for each deferral. If the deferrals are considered in this case, deny authorization of the unprecedented Boardman deferral, and decline to amortize costs in any of the deferrals until PGE's 2021 Results of Operations Report (ROO) is available for earnings review purposes.

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The two other controverted issues are Schedule 150 Nonbypassability, where PGE asks the Commission to approve Schedule 150, Transportation Electrification, along with PGE's proposed rate spread allocating the costs to all customers, including direct access customers; and Schedule 90 Subtransmission Rate, where PGE asks the Commission to reject AWEC's proposal to require PGE to offer a subtransmission rate to Schedule 90 customers. PGE proposes instead to study AWEC's recommendation and provide more information on a subtransmission rate in a future GRC.

PGE is dedicated to keeping customer prices as low as possible, while enabling a clean energy future with a stronger, smarter, more resilient, and better integrated electric grid.[7] PGE's strategic vision aligns with Oregon energy and wildfire mitigation policy, as most recently embodied in the 100 percent Clean Electricity law (House Bill 2021)[8] and in SB 762. By allowing PGE an opportunity to include the carbon-free Faraday Repowering project in rates in a Phase II of this case, supporting timely wildfire mitigation cost recovery, more equitably balancing responsibility for the costs of major outage events, and rejecting the Boardman deferral and parties' requests to prematurely amortize the emergency deferrals, the Commission can support PGE's efforts to meet both the challenges of climate change and the imperative of achieving an emissions-free energy supply, while maintaining reasonable rates for customers.

II. STIPULATIONS

PGE requests that the Commission approve the four partial stipulations which, together, resolve most of the issues in this case in a balanced and reasonable manner.

The first partial stipulation was entered on September 30, 2021, between PGE, Public

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[7] PGE/100, Pope-Sims/1-3.
[8] House Bill (HB) 2021 (2021). Available at: https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled.

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Utility Commission of Oregon Staff (Staff), the Oregon Citizens' Utility Board (CUB), the Alliance of Western Energy Consumers (AWEC), Fred Meyer Stores and Quality Food Centers, Division of The Kroger Co. (Kroger), and Walmart, Inc. (Walmart).[9] Calpine Solutions (Calpine) does not oppose the stipulation.[10] The stipulation resolved all cost of capital issues. Specifically, parties agreed to the following: 9.5 percent return on equity (ROE), 50 percent long-term debt and 50 percent common equity capital structure, 4.125 percent cost of long-term debt, and an overall rate of return of 6.813 percent. [11]

The second partial stipulation was entered on December 2, 2021, between PGE, Staff, CUB, AWEC, Kroger, and Walmart.[12] Calpine does not oppose the stipulation.[13] The second partial stipulation resolved a number of discrete revenue requirement issues,[14] including: Parties agreed to the capital costs of the new Integrated Operations Center to be included in rates.[15] Parties agreed that the costs of the February 2021 ice storm should not affect the Level III Outage Accrual calculation or the Level III Reserve and that parties would not oppose approval of PGE's February 2021 Ice Storm emergency deferral in Docket UM 2156.[16] And parties agreed to move the Oregon Corporate Activities Tax (OCAT) into base rates and terminate the OCAT deferral in Docket UM 2037.[17]

The third partial stipulation was entered on January 18, 2022, between PGE, Staff, CUB, AWEC, Kroger, Walmart, and Small Business Utility Advocate (SBUA).[18] Calpine does not

[9] First Partial Stipulation at 1 (Sept. 30, 2021).
[10] First Partial Stipulation at 1.
[11] First Partial Stipulation at 2.
[12] Second Partial Stipulation at 1 (Dec. 2, 2021).
[13] Second Partial Stipulation at 1.
[14] Stipulating Parties/200, Muldoon-Gehrke-Mullins-Bieber-Chriss-Ferchland/2-3.
[15] Second Partial Stipulation at 2.
[16] Second Partial Stipulation at 2.
[17] Second Partial Stipulation at 5.
[18] Third Partial Stipulation at 1 (Jan. 18, 2022).

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oppose the stipulation.[19] The third partial stipulation resolved all remaining revenue requirement issues, with three specific exceptions, for a $10 million increase in non-NVPC revenue requirement.[20] The $10 million does not include moving the OCAT to base rates, as agreed upon in the second partial stipulation.[21] PGE agreed to remove Faraday Repowering from the May 9, 2022 rate effective date revenue requirement.[22] PGE also agreed to permanently cease collection of residential customer deposits,[23] and to end its decoupling mechanisms.[24]

The fourth partial stipulation was entered on February 7, 2022, between PGE, Staff, CUB, AWEC, Kroger, Walmart, Calpine, and SBUA (Stipulating Parties).[25] The fourth partial stipulation resolved most of the issues remaining in the case. Specifically, in the interest of settlement, the Stipulating Parties agreed to the following:

1. Fee Free Bank Card: Going forward, non-residential customers may pay up to $1,500 per billing cycle using a credit card or other card method, and this program will not end when the COVID-19 state of emergency ends.
2. Trojan Nuclear Decommissioning Trust (NDT): As proposed by AWEC, PGE will return the 2018 claim year Department of Energy (DOE) reimbursement of $2,960,544, received in December 2019, to customers using Schedule 143 over a one-year period beginning on May 9, 2022. PGE will use the amounts received from DOE for the 2020 claim year for the refund. PGE will also return the $352,098 residual balance of Schedule 143 to customers over this same period.

[19] Third Partial Stipulation at 1.
[20] Third Partial Stipulation at 2.
[21] Third Partial Stipulation at 2.
[22] Third Partial Stipulation at 3.
[23] Third Partial Stipulation at 4.
[24] Third Partial Stipulation at 4.
[25] The Fourth Partial Stipulation is being submitted to the Commission concurrently with the parties' prehearing briefs. Accordingly, under OAR 860-001-0350(7)(a), the parties are including explanatory briefing in support of the Fourth Partial Stipulation in their prehearing briefs.

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3. Marginal Cost of Service: PGE's proposed marginal cost of service studies will be used, with updates to loads, forecasted natural gas prices, and cost of capital.
4. Customer Impact Offset: A customer impact offset that moves $1.607 million from Schedule 83, $3.654 million from Schedules 85/485, $2.061 million from Schedules 89/489/689, and $1.15 million from Schedule 90, and applies $6.812 million to Schedule 7 and $1.668 million to Schedule 32.[26]
5. Residential Basic Charge: The Schedule 7 Residential Basic Charge will be bifurcated, with the Single-Family Basic Charge set at $11 and the Multi-Family Basic Charge being lowered to $8.
6. Residential Line Extension Allowance: There will be no change to the Schedule 7 Line Extension Allowance as a result of this case.
7. Temporary Service: Accept PGE's proposed changes to temporary service,[27] and do not require a service guaranty.
8. Generation Demand Charges: Create generation demand charges for Schedules 83 and 85, assigning 25 percent of generation to the new demand charge for each schedule. In PGE's next GRC, PGE will further increase generation demand charges or explain why such increases are unnecessary.
9. Habitat Restoration: CUB's proposal for a separate Habitat Restoration option will not be addressed in this case. CUB may propose changes to the Habitat Restoration options in Docket UM 1020, and PGE will support consideration of CUB's proposal in that docket. PGE reserves the right to support or oppose CUB's proposal.

[26] CUB does not oppose the rate spread agreed to in the fourth partial stipulation but does not support it.
[27] PGE/1200, Macfarlane-Tang/47-48.

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10. Nonbypassability: Accept PGE's proposal to make Schedule 137 nonbypassable, but do not resolve in this case PGE's proposal to make Schedule 135 nonbypassable.

11. Schedule 138: PGE will include the following language suggested by CUB in Schedule 138: "expenses associated with HB 2193 energy storage pilots." This agreement does not preclude PGE from proposing changes to energy-storage-related cost recovery under schedules other than Schedule 138 in the future.

The fourth partial stipulation does not result in a change to the $10 million non-NVPC revenue requirement increase agreed upon in the third partial stipulation. The rate impacts by class under the rate spread agreed to in the fourth partial stipulation are shown in the table in Attachment 1 to this prehearing brief.[28] The fourth partial stipulation was the result of negotiations between the parties in the proceeding and represents a compromise in the positions of the Stipulating Parties. The fourth partial stipulation results in a rate spread, rate design, and specific programs that are fair, just, and reasonable, and will benefit PGE's customers. The Commission should approve all four partial stipulations as-filed because they represent reasonable compromises on the issues resolved and will result in fair, just, and reasonable rates.[29]

III. FARADAY REPOWERING

PGE is repowering the 46 MW Faraday Hydro Facility on the Clackamas River to replace the five original turbine units constructed in 1907 (Faraday Units 1-5) with two higher-efficiency turbines (Faraday Units 7-8).[30] The new turbines will be housed in a reinforced concrete structure

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[28] Stipulating Parties/400.
[29] Stipulating Parties/100, Muldoon-Gehrke-Mullins-Bieber-Chriss-Ferchland/6; Stipulating Parties/200, Muldoon-Gehrke-Mullins-Bieber-Chriss-Ferchland/10; Stipulating Parties/300, Muldoon-Gehrke-Mullins-Bieber-Chriss-Steele-Ferchland/10.
[30] PGE/700, Jenkins-Cristea/4.

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with new flood protection systems to better protect the facility from floods and seismic events, ensuring that PGE can continue to safely and reliably operate the facility for decades to come.[31] Without these upgrades, PGE would likely have been forced to decommission Faraday, one of its few firm, non-emitting generation resources.[32]

Although the project was originally expected to be complete before the rate-effective date of this case, multiple challenges, including extreme weather, wildfires and COVID-19, delayed construction.[33] The project is now more than two-thirds complete, and the current expected in-service date is in the fourth quarter of 2022.[34]

In the third stipulation, parties agreed that PGE would remove Faraday from the revenue requirement for the May 9, 2022, rate-effective date and that parties would continue to litigate how and when the Commission should determine the appropriate ratemaking treatment for Faraday given the new in-service date.[35] The repowering costs for Faraday in PGE's filing were $119.4 million, and the removal of these costs reduced PGE's revenue requirement by approximately $17.2 million.

In its surrebuttal testimony filed after the third stipulation, PGE proposed that the Commission open a Phase II of this rate case, to begin in the second half of 2022, in which the parties can evaluate the prudence of the Faraday repowering when the project is nearly complete, and PGE can incorporate the prudently incurred repowering costs into rates once the project is placed in service.[36]

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[31] PGE/700, Jenkins-Cristea/4-5.
[32] *See* PGE/2600, Bekkedahl-Tinker/6-9; PGE/1900, Bekkedahl-Cristea/15-16, 30.
[33] PGE/700, Jenkins-Cristea/5; PGE/1900, Bekkedahl-Cristea/23-24, 27.
[34] PGE/1900, Bekkedahl-Cristea/27; PGE/2600, Bekkedahl-Tinker /10.
[35] Stipulating Parties/300, Muldoon-Gehrke-Mullins-Bieber-Chriss-Steele-Ferchland/5-6.
[36] PGE/2600, Bekkedahl-Tinker/1-2, 12.

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A. Repowering was necessary to ensure reliable access to a valuable non-emitting capacity resource.

Prior to the repowering project, the five units being replaced were housed in an unreinforced masonry building that was seismically unfit and at increased risk of flooding because the generator flow and powerhouse windows were below the extreme-high-flow-event water level.[37] Already more than a century old, the facility had outlived its original design life and did not meet current structural code.[38] Keeping Faraday operational required increasing O&M costs, and the facility was expected to experience more outages and repair costs due to flooding as high-flow events become increasingly frequent.[39] As a result, PGE would likely have been forced to decommission Faraday had it decided not to repower the facility.[40]

Repowering Faraday will result in a plant that is safer and more reliable, with increased production capacity and new production tax credits (PTCs).[41] The repowered plant will have a design life of more than 40 years, ensuring that PGE will be able to rely on Faraday for decades to come.[42] This is particularly important because Faraday is a non-emitting capacity resource, and there is a capacity shortage in the region following the retirement of many coal and natural gas plants.[43] Repowering Faraday so that it can continue to reliably generate will help PGE eliminate carbon emissions from its power supply portfolio and achieve Oregon's and the Company's decarbonization goals, reflected most recently in the passage of House Bill 2021.[44] In its testimony, Staff questioned PGE's decision to repower rather than decommission Faraday.[45]

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[37] PGE/700, Jenkins-Cristea/5; PGE/1900, Bekkedahl-Cristea/14.
[38] PGE/700, Jenkins-Cristea/5.
[39] PGE/700, Jenkins-Cristea/5.
[40] *See* PGE/2600, Bekkedahl-Tinker/6-9; PGE/1900, Bekkedahl-Cristea/15-16, 30.
[41] PGE/1900, Bekkedahl-Cristea/17; PGE/2600, Bekkedahl-Tinker/8.
[42] PGE/700, Jenkins-Cristea/5.
[43] PGE/1900, Bekkedahl-Cristea/16.
[44] PGE/1900, Bekkedahl-Cristea/16-17.
[45] Staff/1000, Enright/18.

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However, as discussed above, PGE explained why Faraday is an important component of PGE's non-emitting, capacity portfolio in the future,[46] and PGE's integrated resource plans (IRPs) are already projecting capacity deficiencies.[47] Because of the regional capacity shortage and emissions-reduction requirements, hydro resources are extremely valuable, and it would be very challenging to replace Faraday with a similar resource if the plant were decommissioned.[48]

Staff and AWEC also criticize the delays experienced by the repowering project.[49] However, PGE explained that the delays resulted from a variety of factors outside PGE's control, including the 2020 wildfires, flooding events in 2020 and early 2021, the 2021 ice storm, and the ongoing COVID-19 pandemic.[50] These events necessitated several pauses in construction work for safety.[51] PGE's testimony detailed the proactive steps PGE took to keep the project on track, including negotiating contract amendments with the general contractor to strengthen protections against delays.[52] Although the project is not coming online as originally scheduled, PGE expects to bring this major project online later this year and is already delivering its forecast benefits to customers in the Annual Power Cost Update Tariff (AUT), despite facing a variety of unforeseeable challenges.[53]

B. Phase II is a fair and efficient way to timely bring Faraday into rates.

In reply testimony, PGE proposed that the Commission approve a tariff rider to allow PGE to recover prudently incurred costs for Faraday once the project is placed in-service.[54] Parties opposed this approach. Staff explained that it anticipates the need for a thorough prudence

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[46] PGE/1900, Bekkedahl-Cristea/15-16.
[47] PGE/2600, Bekkedahl-Tinker/7.
[48] PGE/2600, Bekkedahl-Tinker/7.
[49] Staff/2500, Enright/3-4; AWEC/100, Mullins/21; AWEC/300, Mullins/17.
[50] PGE/1900, Bekkedahl-Cristea/23.
[51] PGE/1900, Bekkedahl-Cristea/24.
[52] PGE/1900, Bekkedahl-Cristea/24-26.
[53] PGE/2600, Bekkedahl-Tinker/8.
[54] PGE/1900, Bekkedahl-Cristea/28.

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review,[55] and AWEC advocated that Faraday be considered in PGE's next GRC so that the final project can be fully evaluated for prudence.[56]

After considering the parties' concerns, PGE revised its proposal and now requests that the Commission consider Faraday in Phase II of this rate case, conducted during the second half of 2022, rather than approving a tariff rider at this time.[57] PGE envisions that the second phase will include three rounds of testimony, a hearing if desired, and briefing.[58] This process will provide parties a full opportunity to review and litigate the prudence of the repowering project when the project is nearly complete.[59] Considering Faraday in a Phase II of this case is also more efficient than requiring PGE to file a new rate case to include Faraday in the near future.[60]

In response to PGE's tariff rider approach, Staff expressed concern that Faraday's in-service date is too far removed from the rate-effective date, raising concerns regarding single-issue ratemaking.[61] AWEC argued that if Faraday is considered outside PGE's next GRC, parties should be allowed to raise any relevant issues that may impact PGE's revenue requirement.[62] However, there is ample precedent allowing a major asset into rates months after the effective date of a GRC without requiring a utility to file an entirely new GRC. For example, the Commission approved a tariff filing under which Port Westward could become operational up to eight and a half months after the rates in PGE's rate case took effect without automatically requiring a new rate case.[63] Staff's testimony contains several other examples in which the Commission allowed major assets

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[55] Staff/2500, Enright/8.
[56] AWEC/300, Mullins/19.
[57] PGE/2600, Bekkedahl-Tinker/1, 14-15.
[58] PGE/2600, Bekkedahl-Tinker/15.
[59] PGE/2600, Bekkedahl-Tinker/1-2, 14-15.
[60] *See* PGE/2600, Bekkedahl-Tinker/13-14.
[61] Staff/2500, Enright/8-12.
[62] AWEC/300, Mullins/19.
[63] *In re Portland Gen. Elec. Co., Request for a Gen. Rate Revision*, Docket Nos. UE 180/UE 184, Order No. 07-015 at 50 (Jan. 12, 2007).

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to enter rates via a tariff rider up to seven months after the rate-effective date, without reopening all aspects of rates.[64]

Here, PGE is proposing that Faraday be allowed into rates approximately seven months after the May 9, 2022, rate-effective date in this case.[65] PGE's proposed approach is more conservative than Staff's tariff-rider examples. In each of Staff's examples, the parties determined the prudence of the asset several months before it was placed into service,[66] whereas PGE proposes that the prudence review of Faraday would not occur until shortly before the project is placed in-service.[67] Where, as here, parties have engaged in a "very recent, thoroughly contested rate case which provides a comprehensive analysis of all elements relating to PGE's costs and revenues," it is appropriate to allow a major asset to enter rates after the rate-effective date.[68] In addition, PGE estimates that when Faraday is placed in-service, customers will be benefitting from an additional $100 to $120 million of net plant that will be placed in-service after the rate-effective date of this case and therefore will not be incorporated into rates until PGE's next GRC.[69] Thus, bringing Faraday into rates without another full rate case actually benefits customers.

CUB asserted that a tariff rider is inappropriate because Faraday will barely operate during the 2022 test year.[70] CUB's argument disregards the fact that Faraday provides benefits to customers that are already reflected in rates for the 2022 test year. Specifically, PGE's 2022 AUT included the value of the Faraday repowering PTCs and an energy benefit of approximately $5 million associated with Faraday's total forecast generation, based on an estimated online date for

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[64] Staff/2500, Enright/9.
[65] PGE/2600, Bekkedahl-Tinker/5.
[66] Staff/2500, Enright/9.
[67] PGE/2600, Bekkedahl-Tinker/5-6.
[68] *In re Portland Gen. Elec. Co.'s Revised Tariffs Filed with Regard to Power Costs Deferrals, UM 594 and UM 692, and the Coyote Springs Fixed Costs and BPA Tracker and Schedules for Advice No. 95-11*, Docket UE 93, Order No. 95-1216 at 8 (Nov. 20, 1995).
[69] PGE/2600, Bekkedahl-Tinker/12.
[70] CUB/400, Jenks-Gehrke/23.

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Faraday Units 7 and 8 of December 1, 2022.[71] Allowing the prudently incurred costs associated with the Faraday Repowering project into rates in the fourth quarter of 2022 matches the benefits customers are receiving from Faraday repowering, consistent with the matching principle.[72] CUB's argument is also flawed because all test-year costs other than capital investments are measured as of December 31, 2022. PGE simply proposes to include the costs of a major asset that becomes used and useful during the test year in rates.

IV. WILDFIRE MITIGATION COST RECOVERY

PGE asks the Commission to reject Staff's proposed wildfire mitigation cost recovery mechanism, including Staff's proposal to remove $3 million of PGE's prudent wildfire mitigation and vegetation management costs[73] from the $10 million stipulated revenue requirement and make recovery of these prudent costs subject to Staff's mechanism. Instead, PGE seeks Commission approval of PGE's proposed cost recovery mechanism, Schedule 151, allowing dollar-for-dollar cost recovery of all reasonable and prudent wildfire mitigation costs not in base rates through an automatic adjustment clause (Wildfire Mitigation AAC), consistent with the cost recovery language of SB 762.[74] Finally, PGE has updated its wildfire mitigation costs for 2022 and has described those additional costs in its surrebuttal testimony.[75] PGE is not seeking recovery of

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[71] PGE/2600, Bekkedahl-Tinker/8.
[72] *See, e.g.*, *Town of Norwood v. FERC*, 53 F3d 377, 380-381 (DC Cir 1995) (matching principle requires that "ratepayers are charged with the costs of producing the service they receive"); ORS 757.259(2)(e) (authorizing deferrals "to match appropriately the costs borne by and benefits received by ratepayers"); *In re Pub. Util. Comm'n of Or., Investigation of Automatic Adjustment Clause Pursuant to SB 838*, Docket UM 1330, Order No. 07-572 at 5 (Dec. 19, 2007) (renewable adjustment clause designed to match costs and benefits of renewable resources in rates).
[73] Staff combined PGE's proposed vegetation management and wildfire mitigation costs and, as will be discussed, proposed moving $3 million of these costs to a deferral account where the costs would be subject to various penalties. Staff/600, Dlouhy/24-25. Staff did not specify what percentage of the $3 million was attributable to wildfire mitigation (which includes one element of PGE's vegetation management program), and what percentage was attributable to non-wildfire-mitigation related vegetation management. The entire $3 million was reviewed and deemed prudent and should be recovered in this case. For ease of reference, PGE refers to this withheld amount as $3 million in "wildfire mitigation costs" in this section.
[74] PGE/3000, Macfarlane-Tang/33-35; PGE/3004.
[75] *See* PGE/2800, Bekkedahl-Tinker-Brownlee/5.

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wildfire mitigation costs in this rate case beyond those described in its direct testimony, but seeks to defer these additional costs for recovery at a later date under Schedule 151, the Wildfire Mitigation AAC.

Only Staff raises issues with PGE's request for recovery of wildfire mitigation costs. While Staff does not challenge the prudence of PGE's wildfire mitigation costs, Staff argues that these costs should be subject to a performance-based rate (PBR) mechanism similar to the mechanism the Commission adopted in PacifiCorp's last rate case, Docket UE 374. Staff's proposed Wildfire Mitigation and Vegetation Management (WMVM) mechanism would subject PGE's wildfire mitigation costs—even those deemed prudent in this case—to various reductions or penalties based on the number of vegetation management violations Commission Safety Staff finds across PGE's service territory.

While Staff appears focused on implementing uniform regulatory policy across utilities with respect to wildfire mitigation costs, Staff's proposed treatment of wildfire mitigation costs is legally unsupportable. SB 762 became effective on July 19, 2021, seven months after the Commission adopted PacifiCorp's PBR mechanism, and it materially changed the legal landscape for recovery of utility wildfire mitigation costs. SB 762 allows utilities to recover all reasonable operating costs and prudent investments in wildfire mitigation through an AAC or other method for timely cost recovery. The Commission has interpreted substantively identical statutory language in other contexts to require dollar-for-dollar cost recovery through an AAC. PGE's proposed Wildfire Mitigation AAC in Schedule 151 is tailored to meet these statutory requirements; Staff's proposed PBR mechanism conflicts with them.

In the event the Commission disagrees with PGE's legal interpretation of SB 762 and elects to adopt a PBR mechanism over PGE's objection, Staff's proposed mechanism should be updated

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to ensure that its incentives and performance goals align with PGE's Wildfire Mitigation Plan[76] by focusing on high-impact vegetation management activities within PGE's service territory. Staff's proposed mechanism would subject PGE's prudently incurred wildfire mitigation costs to penalties based on systemwide vegetation management violations that have no clear nexus to wildfire mitigation or to the actionable items in PGE's Wildfire Mitigation Plan. PGE proposes modifications to Staff's mechanism to more narrowly focus the application of Staff's proposed penalties to activities identified in PGE's Wildfire Mitigation Plan to ensure the mechanism would incentivize, rather than divert resources from, the efforts required by SB 762. To be clear, PGE does not believe that Staff's mechanism, even as modified by PGE, is legally supportable in light of SB 762's cost recovery language, but PGE's alternative is better aligned with the legislative intent of the statute.

Finally, PGE has updated its wildfire mitigation costs for 2022 based on the development and implementation of its Wildfire Mitigation Plan. PGE has described those additional costs in its surrebuttal testimony.[77] PGE is not seeking recovery of any wildfire mitigation costs in this rate case beyond those described in its direct testimony. Instead, PGE seeks to defer the additional costs identified in its surrebuttal testimony for review and recovery at a later date under its Wildfire Mitigation AAC. PGE asks the Commission to approve its updated request for deferral in Docket UM 2019 to allow PGE to defer these additional costs.

A. PGE's proposed Wildfire Mitigation AAC implements the statutory requirements of SB 762 and should be adopted.

PGE seeks Commission approval of its new Wildfire Mitigation AAC that would allow

[76] PGE filed its 2022 Wildfire Mitigation Plan on December 30, 2021, in Docket UM 2208. This is the "wildfire protection plan" required by SB 762. PGE uses these terms interchangeably.
[77] *See* PGE/2800, Bekkedahl-Tinker-Brownlee/5.

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dollar-for-dollar cost recovery of those costs through an AAC.[78] This mechanism is consistent with the cost recovery language of SB 762, which allows utilities to recover all reasonable operating costs and prudent investments in wildfire mitigation through an AAC or other method for timely cost recovery. SB 762's cost recovery provisions apply to all utility costs expended to "to develop, implement or operate" wildfire protection plans, which encompasses the test year wildfire mitigation costs proposed by PGE in this proceeding. SB 762 became effective on July 19, 2021, and its cost recovery provisions have not, to PGE's knowledge, been fully addressed by this Commission.

1. The Commission has interpreted statutory cost recovery language identical to SB 762's to require dollar-for-dollar recovery of costs through an AAC.

The cost recovery language of SB 762 states as follows:

> 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.[79]

This key language from SB 762 directing timely cost recovery for wildfire mitigation costs is identical to the language of ORS 469A.120(2)(a) directing timely cost recovery for renewable resource portfolio standard (RPS) compliance costs. In Docket UM 1330, the Commission implemented that RPS language through an AAC and deferred accounting without an earnings review.[80]

The RPS cost recovery language mirrors the language in SB 762:

> The Public Utility Commission shall establish an automatic adjustment clause as defined in ORS 757.210 (Hearing to establish new schedules) or

[78] PGE/2800, Bekkedahl-Tinker-Brownlee/4-5; PGE/3000, Macfarlane-Tang/33-35; PGE/3004 (Schedule 151—Wildfire Mitigation Cost Recovery).
[79] SB 762, Section 3 (8). Available at: https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/SB762/Enrolled.
[80] Docket UM 1330, Order No. 07-572 at 8.

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> another method that allows timely recovery of costs prudently incurred by an electric company to construct or otherwise acquire facilities that generate electricity from renewable energy sources, costs related to associated electricity transmission and costs related to associated energy storage.[81]

In Docket UM 1662, the Commission provided a more detailed interpretation of this language, stating that it, "explicitly mandate[s] the use of an automatic adjustment clause to provide dollar-for-dollar recovery for fixed capital costs associated with RPS compliance."[82] Accordingly, PGE currently recovers the prudently incurred capital costs of renewable resources through its renewable adjustment clause (RAC), Schedule 122, which allows cost recovery through an AAC and deferred accounting without an earnings review.

2. PGE's proposed Wildfire Mitigation AAC is modeled after PGE's RAC.

Given the use of the same legislative language for cost recovery in the RPS statute and in SB 762, PGE modeled its Wildfire Mitigation AAC on its RAC.[83] Under PGE's proposed Wildfire Mitigation AAC, PGE would submit a deferral application with a forecast of wildfire O&M and capital spending for the forthcoming year, incremental to what is included in base rates, to be collected from customers as PGE is making the investments.[84] In this case, PGE proposes to update its pending application for deferral in Docket UM 2019 to include the AAC and add PGE's estimated spending. Unless otherwise directed by the Commission, this deferral of wildfire mitigation costs would be amortized over the next calendar year through Schedule 151, subject to a determination that the wildfire mitigation costs were actually incurred, are covered by subsection 3(8) of SB 762, and are prudent.[85] As with costs subject to the RAC, recovery of these costs would

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[81] ORS 469A.120(2)(a).
[82] *In re Portland Gen. Elec. Co. and PacifiCorp, dba Pac. Power, Request for Generic Power Cost Adjustment Mechanism Investigation,* Docket UM 1662, Order No. 15-408 at 7 (Dec. 18, 2015).
[83] PGE/3000, Macfarlane-Tang/33-34.
[84] PGE/3000, Macfarlane-Tang/33.
[85] PGE/3000, Macfarlane-Tang/33.

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not be subject to an earnings review. The Wildfire Mitigation AAC in PGE's proposed Schedule 151 thus complies with the plain language of SB 762 requiring "all" wildfire mitigation-related costs to be recovered in a "timely" fashion.

3. *Staff's proposed PBR mechanism is inconsistent with SB 762.*

Staff proposes a different mechanism for recovery of wildfire costs, one based on the PBR mechanism the Commission adopted in PacifiCorp's last rate case, Docket UE 374.[86] That mechanism would subject PGE's wildfire mitigation and vegetation management costs—including $3 million of costs already deemed prudent in this case—to an earnings review with a threshold that would vary based on the number of vegetation management violations found by Commission Safety Staff across PGE's service territory in a given year.

Staff proposes to group PGE's separate wildfire mitigation program and vegetation management programs together for purposes of its mechanism, which would apply to what Staff refers to as WMVM O&M expenses. (PGE will refer to Staff's proposed mechanism as its "WMVM mechanism.") Under Staff's proposal, expenses associated with vegetation management and wildfire mitigation measures, as well as expenses associated with recovery of new capital investments and the return on those investments, would be placed into a deferral account.[87] At the outset, Staff recommends that the Commission withhold $3 million of PGE's requested O&M costs from recovery in this proceeding—where they have been reviewed and deemed prudent—and put them into the WMVM deferral account where they would be subject to review under the mechanism. To the extent PGE's actual spending deviated from the spending in its base rates, PGE would add incremental or decremental costs to the deferral account.[88]

For the first $6 million in WMVM costs added to the deferral account, PGE's cost recovery

[86] Staff/600, Dlouhy/18.
[87] Staff/600, Dlouhy/25-26.
[88] Staff/600, Dlouhy/18.

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would turn on the number of vegetation management violations found by Commission Safety Staff during a given year and the subsequent application of an earnings test.[89] If Commission Safety Staff were to find fewer than 150 vegetation management violations across PGE's system in a given year, PGE could recover its prudently incurred costs up to its authorized ROE.[90] If Commission Safety Staff were to find more than 150 vegetation management violations, various penalties would kick in and reduce the applicable earnings threshold below PGE's authorized ROE.[91] These basis point reductions would generally range from 100 to 200 basis points, depending on the number of vegetation management violations identified by Commission Safety Staff. PGE's applicable ROE could be reduced another 50 basis points if a violation were to occur in an area of elevated or extreme fire risk,[92] or by an additional 50 basis points if Staff were to find climbable tree violations that were not addressed by PGE within 30 days. For any incremental additional WMVM costs added to the deferral account beyond the first $6 million, a somewhat different set of penalties would apply.[93] Staff suggests this mechanism remain in place until May 5, 2024, at which point PGE should be required to "demonstrate that the deferral has been effective and that its continued use is warranted."[94]

a) Staff's proposed WMVM mechanism fails to authorize recovery of all prudently incurred costs for wildfire mitigation.

Staff's proposed WMVM mechanism is inconsistent with SB 762 because it puts prudently incurred wildfire mitigation costs at risk of non-recovery. When confronted with this obvious inconsistency, Staff relies heavily on the fact that the Commission adopted a similar mechanism

[89] Staff/600, Dlouhy/28-29.
[90] Staff/600, Dlouhy/28.
[91] Staff/600, Dlouhy/28.
[92] Staff/600, Dlouhy/28. These are also referred to as Tier 2 and Tier 3 areas. *See* PGE/800, Bekkedahl-Jenkins/47.
[93] Above the $6 million, penalties would be triggered if Commission Safety Staff found 300 violations or at least one violation occurs in a Tier 2 or Tier 3 zone, in which case the earnings test would use PGE's authorized ROE minus 50 basis points. Staff/600, Dlouhy/28.
[94] Staff/600, Dlouhy/28.

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in Docket UE 374 to support the mechanism's legality.[95] But simply pointing to the adoption of a similar mechanism for PacifiCorp in 2020 as support for a mechanism here is unpersuasive, particularly given the significant changes in Oregon law since the Commission approved PacifiCorp's mechanism.[96] Indeed, PacifiCorp filed an application on January 5, 2022, seeking deferral of costs associated with its SB 762 wildfire protection plan and indicated it would make a filing later this year seeking approval of a rate schedule and AAC to begin recovery of those costs.[97]

Staff also notes that its WMVM mechanism gives PGE the *opportunity* to fully recover its prudently incurred costs.[98] That is not enough. The cost recovery language of SB 762 gives utilities the right to recover *all* prudently incurred wildfire mitigation costs. In Docket UM 1662, the Commission expressly recognized the significant distinction between a general legislative mandate providing only an opportunity for cost recovery and a more specific mandate for timely and complete cost recovery under an AAC.[99] The specific cost recovery mandate of SB 762 is substantively identical to the language the Commission interpreted in Docket UM 1662. Staff proposes to put incremental additional wildfire mitigation costs in a deferral account where PGE would face a double risk of non-recovery—first when the costs are reviewed for prudence, and again when they are made subject to Staff's proposed penalties.[100] SB 762 allows non-recovery only for imprudence, not as a penalty for other conduct.

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[95] *See, e.g.,* Staff/2400, Dlouhy/7-11 (repeatedly justifying mechanism based on its adoption in Docket UE 374).
[96] Staff/2400, Dlouhy/10.
[97] *See In re PacifiCorp, dba Pac. Power Application for Approval of Deferred Accounting for Operating Costs and Capital Investments Made to Implement and Operate the Company's Or. Wildfire Protection Plan*, Docket UM 2221, Application for Deferred Accounting (Jan. 5, 2022).
[98] Staff/2400, Dlouhy/10
[99] Docket UM 1662, Order No. 15-408 at 7.
[100] This double risk of non-recovery is illustrated by Staff's proposal in this case to withhold $3 million in costs already deemed prudent in this proceeding and put them in the deferral account where they would again be put at risk.

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b) Staff's proposed WMVM mechanism fails to include an AAC.

As noted previously, cost recovery language substantively identical to SB 762's has been interpreted by the Commission to "explicitly mandate[] the use of an automatic adjustment clause."[101] Nevertheless, Staff argues that its WMVM mechanism—which does not include an AAC—is an acceptable alternative under SB 762 because it creates "[l]ess than a year of regulatory lag."[102] Unfortunately, Staff miscalculates the timing of cost recovery under its mechanism. As PGE explains in testimony, the regulatory lag created by Staff's mechanism is close to *two years*, not less than one.[103] PGE's proposed AAC, by contrast, would allow for timely recovery of prudently incurred wildfire mitigation costs. PGE is unaware of any regulatory mechanism other than an AAC that would allow PGE to fully recover its wildfire mitigation costs without meaningful regulatory lag.[104]

c) Staff's proposed WMVM mechanism prioritizes general vegetation management over wildfire mitigation activities in PGE's Wildfire Mitigation Plan and subjects PGE to a double set of penalties.

Finally, Staff's WMVM mechanism is inconsistent with the legislative intent of SB 762 for a number of reasons. SB 762 creates explicit requirements for utilities to create and implement comprehensive risk-based wildfire protection plans. In doing so, the legislature emphasized the importance of focused, data-driven wildfire mitigation efforts in Oregon. With respect to vegetation management—one element of the constellation of wildfire mitigation activities required by the statute—SB 762 requires utilities to focus specifically on areas that are at "heightened risk

[101] Docket UM 1662, Order No. 15-408 at 7.
[102] Staff/2400, Dlouhy/10-11.
[103] PGE/3000, Macfarlane-Tang/34-35 (explaining that, under Staff's mechanism, funds invested by PGE in January 2022 would not be recovered from customers until November 2023).
[104] PGE/3000, Macfarlane-Tang/34.

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of wildfire."[105] PGE's Advanced Wildfire Risk Reduction (AWRR) program addresses this element of SB 762 by specifically addressing vegetation management in high risk fire zones (HRFZ).[106] However, Staff's WMVM mechanism would turn on its head the requirement that utilities sharpen their focus on specific vegetation management activities by prioritizing general vegetation management, rather than the data-driven wildfire mitigation activities required by SB 762. Indeed, PGE's analysis demonstrates that fewer than 6 percent of PGE's probable vegetation management violations over the past two years were located in HRFZs.[107] Staff's mechanism would contravene the legislative intent by diverting attention from these high priority areas and from PGE's other high-impact wildfire mitigation efforts.[108]

Moreover, Staff's WMVM mechanism undermines SB 762's comprehensive and balanced compliance scheme by imposing penalties that are additive to SB 762's penalty provisions. SB 762 provides for civil penalties in the event a utility violates its statutory provisions or a Commission rule adopted under the statute.[109] By providing both penalties and favorable cost recovery provisions, SB 762 creates a balanced compliance scheme for accelerating utility wildfire mitigation efforts. Staff's proposal to impose a second set of penalties applicable to wildfire mitigation efforts is punitive and contravenes SB 762.

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[105] SB 762, Section 3 (2)(a). Available at: https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/SB762/Enrolled; *see also* OAR 860-300-0002(1)(h).

[106] PGE's vegetation management contains five separate elements, of which AWRR is only one. PGE/2800, Bekkedahl-Tinker-Brownlee/10.

[107] PGE/2800, Bekkedahl-Tinker-Brownlee/17.

[108] PGE/2800, Bekkedahl-Tinker-Brownlee/15-16.

[109] SB 762, Section 3a. Available at: https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/SB762/Enrolled. *See also* PGE/3000, Bekkedahl-Tinker-Brownlee/9.

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B. In the event the Commission imposes a WMVM mechanism for wildfire mitigation costs, Staff's proposed mechanism should be updated to reflect activities specific to PGE's Wildfire Mitigation Plan and more recent advances in utility wildfire planning.

Any mechanism that puts prudently incurred wildfire costs at risk of non-recovery is inconsistent with SB 762's clear directives. In the event the Commission disagrees with PGE's interpretation of SB 762 and decides to adopt a WMVM mechanism in this docket, the Commission should update the mechanism's design to recognize best practices in wildfire mitigation. Specifically, the Commission should narrow the scope of the mechanism to address vegetation management activities that are truly focused on wildfire mitigation. In PGE's case, that would be its AWRR program. PGE makes the following recommendations:[110]

First, any WMVM mechanism should apply only to incremental costs above and beyond what is included in base rates (that is, the amounts proposed in PGE's direct testimony). The costs submitted in PGE's direct testimony were reviewed by Staff and other parties for prudence, and no party took issue with them. There is no justification for holding back these costs and putting them at risk of non-recovery once again.

Second, the WMVM mechanism should apply only to AWRR costs. The goal of the WMVM mechanism, as PGE understands it, is to reduce wildfire risk by penalizing a utility for failing to invest appropriately in vegetation management activities that reduce wildfire risk. As PGE has explained, AWRR is a vegetation management program that specifically focuses on reducing the risk of wildfire associated with vegetation near utility assets. AWRR is a part of PGE's Wildfire Mitigation Plan and focuses on advanced vegetation management in HRFZs.

Third, incremental AWRR costs should be subject to a prudence review. Finally, the metric used to determine any penalties would be based solely on the number of confirmed vegetation

[110] PGE/2800, Bekkedahl-Tinker-Brownlee/27.

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management violations in PGE's HRFZs.

1. The WMVM mechanism should apply only to incremental new costs beyond those proposed in PGE's direct case.

No party takes issue with the prudence of the wildfire mitigation or vegetation management costs in PGE's direct case and those costs should be recovered in this case. Nevertheless, Staff recommends removing $3 million from PGE's stipulated $10 million revenue requirement and putting it in a deferral account where it would be at risk of non-recovery.[111] Staff's only stated justification for putting these dollars at risk is because Staff "[has] a concern regarding PGE's lack of multi-year budgeting," as it may indicate a lack of commitment to spending to address wildfire risk.[112] Apparently, Staff believes that because PGE only included test year expenses in this rate case, rather than a multi-year wildfire mitigation budget, PGE's commitment to long-term wildfire mitigation efforts is unclear.[113]

Aside from its inconsistency with SB 762, this rationale for withholding cost recovery for prudent wildfire mitigation costs is simply not credible.[114] PGE's proactive request for increased wildfire mitigation funding in this docket and its detailed, multi-phase Wildfire Mitigation Plan are evidence of PGE's commitment to wildfire mitigation.[115] Moreover, cost recovery in a rate case is based on a test year revenue requirement; it does not incorporate budget forecasts or project

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[111] Staff/600, Dlouhy/24-25; Stipulating Parties/300, Muldoon-Gehrke-Mullins-Bieber-Chriss-Steele-Ferchland/5 (explaining that the parties will continue to litigate the $3 million holdback associated with Staff's WFVM mechanism, and that if Staff's position prevails, it will be deducted from the $10 million stipulated revenue requirement).

[112] Staff/600, Dlouhy/24-25.

[113] Staff/600, Dlouhy/25.

[114] The dubious nature of this assertion from Mr. Dlouhy is reinforced by Mr. Muldoon's articulation of Staff's rationale as precisely the opposite. Mr. Muldoon describes Staff's withholding of prudently incurred costs a measure intended "[t]o ensure PGE is also focused on <u>cost control</u>." Staff/100, Muldoon/9 (emphasis added). Elsewhere, Mr. Dlouhy gives an entirely different explanation for withholding cost recovery, explaining that it was intended to "incentivize the Company to improve its vegetation management practices." Staff/600, Dlouhy/26.

[115] *See, e.g.,* Staff/100, Muldoon/8 (noting that "PGE has significantly increased the amounts included in its revenue requirement for Wildfire Mitigation and Vegetation Management (WMVM) as compared to its most recent rate case."). PGE would also invite the Commission to review its 2022 Wildfire Mitigation Plan (PGE/2801).

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work plans beyond the test year.[116]

Moreover, Staff's assertion that PGE needs a new incentive to improve its vegetation management practices is puzzling in light of the uncontested evidence that, as Mr. Muldoon notes, PGE has significantly increased the amounts included in its revenue requirement for wildfire mitigation and vegetation management since its last rate case.[117] The $3 million Staff proposes withholding should be included in PGE's rate recovery in this proceeding.

2. Any PBR mechanism intended to promote wildfire mitigation through vegetation management violations should focus on PGE's AWRR program.

PGE developed its AWRR program specifically to reduce the risk of wildfire associated with vegetation near utility assets,[118] and is the component of PGE's overall vegetation management program that was specifically developed to mitigate wildfire risk. PGE's AWRR program focuses initially on vegetation in PGE-identified HRFZ. It includes annual inspections of all Public Safety Power Shutoff (PSPS) mileage as well as "hotspot trimming," which refers to trimming vegetation within five feet of PSPS feeders.[119] The program also requires annual identification and mitigation of "P1" Hazard/Danger Trees and "P2" Trees, which are non-hazard/danger, but exhibit articulable arboricultural defects and are within fall-in proximity to PGE's overhead assets.[120]

As noted previously, Staff's proposed target—general vegetation management—occurs across PGE's entire service area. While PGE proactively manages vegetation in order to keep the entire system safe and reliable under all conditions, including during ice, snow, or windstorms, general vegetation management does not specifically target wildfire prevention or mitigation.

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[116] *See* PGE/2000, Bekkedahl-Jenkins/5.
[117] Staff/100, Muldoon/8.
[118] PGE/800, Bekkedahl-Jenkins/48.
[119] PGE/800, Bekkedahl-Jenkins/48.
[120] PGE/800, Bekkedahl-Jenkins/48. Additional details about the AWRR program are at PGE/2801 (PGE 2022 Wildfire Mitigation Plan).

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Staff's proposed WMVM mechanism would penalize PGE for vegetation management violations anywhere on PGE's system, even if those violations had no clear nexus to wildfire mitigation. The mechanism would thus divert PGE's resources away from high-impact wildfire mitigation efforts to generic systemwide vegetation management.[121] PGE has created a PGE-specific Wildfire Mitigation Plan that provides a roadmap for creating incentives that actually align with wildfire risk management.[122] Focusing on AWRR would help mitigate this risk.

3. The performance metric should be the number of vegetation management violations in HRFZ; violation thresholds and associated penalties should be updated to reflect the new targets.

PGE suggests the performance metric for any WMVM mechanism should be the number of probable vegetation management violations identified in the annual Commission Safety vegetation report that are located in HRFZ. In addition, violation thresholds and associated penalties should be updated to reflect the new targets. PGE proposes the following thresholds and associated penalties:

Table 1. Proposed AWRR Performance-Based Rate Criteria[123]

Violations Level	Threshold of vegetation management violations in HRFZ	Penalty in Basis Points (bps)
Level I	> 30 violations	100 bps reduction
Level II	> 60 violations	150 bps reduction
Level III	> 100 violations	200 bps reduction
Plus additional 50 bps reduction if it is a climbable tree violation in a HRFZ that is not addressed by PGE within 30 days.		

[121] *See* PGE/2800, Bekkedahl-Tinker-Brownlee/15-16.

[122] Staff does not appear to have analyzed any differences between PGE's and PacifiCorp's service territories and respective wildfire risks or the spending requests of the respective utilities in the two cases. Each utility's service territory varies and will have different fire risks and characteristics that will require different wildfire mitigation activities. PGE/800, Bekkedahl-Jenkins/45-46 (noting there is no one-size-fits-all approach to wildfire mitigation because each utility's service territory varies and will have different fire risks and characteristics). The characteristics of wildfire risk in PGE's service territory make Staff's focus on generalized vegetation management especially unhelpful in terms of mitigating wildfire risk. *Id. See* PGE/2800, Bekkedahl-Tinker-Brownlee/17-18.

[123] PGE/2800, Bekkedahl-Tinker-Brownee/28.

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This table is based on Table 4 provided in Staff's opening testimony,[124] with the modifications described above. For Level I violations, PGE proposes using the average number of probable vegetation management violations that were identified by Commission Safety Staff in 2020 and 2021, thirty (30), that were located in the HRFZ identified in PGE's 2022 Wildfire Mitigation Plan. PGE proposes keeping the Level I penalty at the same level proposed by Staff: 100 basis point reduction. PGE proportionally adjusted the number of violations for Level II and Level III to match those in Staff's original Table 4. Thus, the violations needed to reach Level II are twice as many violations as the Level I. Finally, PGE includes Staff's proposed additional 50 basis point reduction in the event of a climbable tree violation but modified this element to be specific to climbable tree violations in HRFZ.[125]

PGE has raised a number of additional concerns with Staff's proposed WMVM mechanism and continues to believe a mechanism intended primarily to address wildfire risk would benefit from wholesale revision.[126] But with the above modifications, the PBR mechanism would better align with OAR 860-300-0002(1)(h), which directs a utility wildfire protection plan to include, among other things, a "[d]escription of the procedures, standards, and time frames that the Public Utility will use to carry out vegetation management in areas the Public Utility identified as heightened risk of wildfire."[127]

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[124] *See*, Table 4. Proposed WMVM Performance-Based Rate Criteria. Staff/600, Dlouhy/28.

[125] PGE has noted concerns about the methodology Commission Safety Staff use to identify "probable violations." PGE/2000, Bekkedahl-Jenkins/6. The Commission should ensure that any probable violations identified by Staff are confirmed as actual violations before any penalties would apply. Staff/600, Dlouhy/28.

[126] For example, PGE has noted that the mechanism is punitive, complex, and cumbersome, all characteristics that could be improved as the Commission gains more experience with PBR mechanisms. *See*, e.g., PGE/2000, Bekkedahl-Jenkins/3,7, 12) (noting that Staff's proposal introduces a great deal of unnecessary complexity into an area that is already complex and evolving and undermines utilities' ability to focus on developing and implementing wildfire mitigation best practices).

[127] OAR 860-300-0002(1)(h)

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C. The Commission should approve PGE's request for deferral in Docket UM 2019 to allow PGE to defer its incremental additional wildfire mitigation costs.

Finally, PGE has updated its wildfire mitigation costs for 2022 and has described those additional costs in its surrebuttal testimony.[128] Since PGE filed its direct case, its planned investments in wildfire mitigation have increased 44 percent for O&M and 67 percent for capital.[129] These increases are due to actions taken to comply with directives in SB 762 and with Commission guidance in the ongoing wildfire mitigation rulemakings. PGE's 2022 Wildfire Mitigation Plan, which was filed on December 30, 2021, was developed in accordance with the Commission's new rules, which provide specific guidance regarding risk modeling, wildfire-related engagement with Public Safety Partners and local communities, PSPS-related communications, education and notifications, inspection and repair, vegetation management and clearances, and inspection and patrol activities within the utility-identified HRFZs.[130]

Recognizing that no party has reviewed these costs, PGE is not seeking recovery of these incremental additional costs in this rate case. Rather, PGE seeks authority to defer these additional incremental costs and seek recovery at a later date under its Wildfire Mitigation AAC. To effectuate this request, PGE proposes to update its pending deferral in Docket UM 2019 to include the Wildfire Mitigation AAC and add its estimated additional incremental spending. PGE asks the Commission to approve its request.[131]

V. LEVEL III OUTAGE MECHANISM

In accordance with the Commission's direction in Dockets UE 335 and UM 1817, PGE

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[128] *See* PGE/2800, Bekkedahl-Tinker-Brownlee/5.
[129] PGE/2800, Bekkedahl-Tinker-Brownlee/5.
[130] *See* PGE/2800, Bekkedahl-Tinker-Brownlee/5.
[131] If the Commission does not approve PGE's mechanism but instead approves a mechanism similar to Staff's, PGE assumes these costs would be subject to deferral under that mechanism and subject to risk of non-recovery based on potential vegetation management violations.

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proposes revisions to its Level III outage mechanism in this case. A Level III outage is one that impacts at least 50,000 customers, renders several substations and feeders out of service, or qualifies for Institute of Electrical and Electronics Engineers (IEEE) Major Event Day exclusion for reliability reporting purposes.[132] Under the current mechanism, PGE collects in base rates an amount equal to the 10-year rolling average of Level III outage costs and accrues the amount to a reserve account for service restoration costs associated with Level III events.[133] Any accrued amount not used for Level III outage costs in a given year carries forward for use in future years.[134] However, if the outage costs in a given year exceed the account balance, PGE's shareholders absorb the excess cost.[135] In other words, the account balance cannot be negative.[136] The 10-year average is updated when PGE files a GRC, meaning the Commission last reset the 10-year average in 2018 in Docket UE 335.[137]

Over the decade since it was adopted,[138] the current, asymmetrical Level III mechanism has proven to be inadequate to address the number and severity of events PGE has experienced, and as a result, it has denied PGE an opportunity to recover significant, prudently incurred Level III outage restoration costs. For example, events that occurred from 2014 to 2016 fully depleted the account, and the $2 million accrual collected from customers in 2017 was inadequate to offset the $11.4 million PGE incurred that year to restore service to customers in the wake of four Level

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[132] PGE/800, Bekkedahl-Jenkins/60.

[133] PGE/800, Bekkedahl-Jenkins/60; *see also* Docket UE 335, Order No. 18-464 at 13; *In re Portland Gen. Elec. Co., Application for the Deferral of Storm-Related Restoration Costs*, Docket UM 1817, Order No. 19-274 at 2 (Aug. 19, 2019).

[134] *See* PGE/2400, Bekkedahl-Tooman/1; *see also* Docket UE 335, Order No. 18-464 at 13; Docket UM 1817, Order No. 19-274 at 2.

[135] PGE/800, Bekkedahl-Jenkins/61; *see also* Order No. 18-464 at 13; Order No. 19-274 at 2, 5.

[136] PGE/800, Bekkedahl-Jenkins/61; *see also* Order No. 18-464 at 13; Order No. 19-274 at 2.

[137] Docket UE 335, Order No. 18-464.

[138] *In re Portland Gen. Elec. Co., Request for a Gen. Rate Revision*, Docket UE 215, Order No. 10-478 at 6 (Dec. 17, 2010).

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III events.[139] PGE has proposed revisions to the mechanism in each of its prior rate cases.[140]

In two recent orders, the Commission acknowledged the need to revise PGE's Level III mechanism and signaled its intent to update the mechanism in this case. In PGE's last GRC, Docket UE 335, the Commission rejected PGE's proposal to implement a symmetrical, uncapped mechanism, but encouraged PGE to refine its proposal to ensure that the mechanism is balanced and incentivizes PGE to develop a resilient system.[141] The Commission expressly invited PGE to return with an alternative proposal.[142]

In Docket UM 1817, PGE's request for deferred accounting for the significant 2017 event costs not covered by the Level III mechanism, the Commission denied the deferral application but again committed to reexamining the Level III mechanism in PGE's next rate case.[143] The Commission "acknowledge[d] the combined effect of the asymmetrical storm fund and the unpredictable nature of severe storm events."[144] The Commission recognized that PGE bears *all* the risk under the current mechanism and that greater storm frequency and intensity from climate change could increase the risk of depleting the Level III account and shifting costs to PGE, unless the event is extraordinary and warrants a deferral.[145] The Commission stated that it is "prepared to consider how to appropriately allocate the risk associated with the cumulative effect of multiple years of above-average storm costs" in this rate case.[146]

In this case, PGE proposes revisions to make the Level III mechanism more symmetrical

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[139] PGE/2400, Bekkedahl-Tooman/9, n.11.
[140] *See In re Portland Gen. Elec. Co., Request for a Gen. Rate Revision*, Docket UE 262, Order No. 13-459 at 7 (Dec. 9, 2013) (withdrawing proposal in settlement); *In re Portland Gen. Elec. Co., Request for a Gen. Rate Revision*, Docket UE 319, Order No. 17-511 at 4 (Dec. 18, 2017); Docket UE 335, Order No. 18-464 at 13-14.
[141] Docket UE 335, Order No. 18-464 at 13-14.
[142] Docket UE 335, Order No. 18-464 at 13-14.
[143] Docket UM 1817, Order No. 19-274 at 14.
[144] Docket UM 1817, Order No. 19-274 at 13.
[145] Docket UM 1817, Order No. 19-274 at 13.
[146] Docket UM 1817, Order No. 19-274 at 14.

and to include sharing. Specifically, PGE proposes that the amount collected in base prices will continue to be based on a 10-year average and will accrue to a reserve account, which can have a negative balance if Level III costs in a given year exceed the positive account balance.[147] If a year has a negative balance, PGE will absorb 10 percent of the actual Level III costs applied to the negative balance.[148] If the amount in the balancing account exceeds positive or negative $12 million, PGE will amortize the excess amount through a charge or credit, and the excess amount will be shared with 90 percent to customers and 10 percent to PGE.[149]

Recognizing that the current mechanism should be changed, Staff and CUB both make their own proposals for revisions. Staff proposes to retain the current asymmetrical mechanism but to annually update the rolling 10-year average amount collected from customers.[150] CUB proposes to allow the Level III account balance to go negative with a hard cap.[151] Specifically, the negative balance of the account would not be allowed to exceed two times the annual accrual amount collected from customers, and any costs incurred beyond the cap would be borne by PGE.[152] AWEC asserts that no change to the structure of the current mechanism is warranted.[153]

A. Strengthening the Level III mechanism supports the Commission's policy of prioritizing safety and promoting emergency preparedness.

When a major event impacts a utility's service territory and its customers, knowing that recovery is available for the costs necessary to restore service allows the utility to focus on the paramount issues of addressing all safety and service concerns, rather than worrying about repair

[147] PGE/800, Bekkedahl-Jenkins/62-63.
[148] PGE/800, Bekkedahl-Jenkins/62-63.
[149] PGE/800, Bekkedahl-Jenkins/62-63.
[150] Staff/1400, St. Brown/10.
[151] CUB/200, Gehrke/19.
[152] CUB/200, Gehrke/19.
[153] AWEC/300, Mullins/22.

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costs immediately.[154] During a major outage event, PGE uses all resources at its disposal, including asking PGE crews to work overtime and sometimes relying on contractors to assist.[155] During such events, PGE cannot simply limit its spending to a pre-determined amount and still meet its commitment to safely restore service to all customers as quickly as possible.[156] While PGE can—and does—work to harden its system in preparation for such events, the occurrence and severity of events is outside PGE's control.

The new deferral process for declared emergencies confirms that the Commission expects utilities to prioritize safety and reliability in the face of extreme weather events and that utilities should have an opportunity to recover the costs imposed by such events.[157] Recognizing that the dynamics of major storms and other service-threatening events have changed, the Commission recently invited utilities to establish pre-filed deferral accounts for expenses incurred responding to an event covered by a federal or state emergency declaration.[158] The Commission observed that this approach would "streamline recovery efforts" following events that significantly impact utility systems.[159]

Although the pre-filed emergency deferrals are an important component of the emergency preparedness and recovery effort, they do not obviate the need for a revised and improved Level III mechanism.[160] The Commission authorized pre-filed emergency deferrals only for declared

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[154] *See In re PacifiCorp, dba Pac. Power, Request for Deferred Accounting Order for Network Damage from Nov. 2012 Storm*, Docket UM 1634, Order No. 12-489, App. A at 2 (Dec. 18, 2012).
[155] *See* PGE/800, Bekkedahl-Jenkins/68.
[156] PGE/800, Bekkedahl-Jenkins/68.
[157] *See In re Pub. Util. Comm'n of Or., Pre-Filed Emergency Deferral Applications,* Docket UM 2181, Order No. 21-259 (Aug. 12, 2021).
[158] Docket UM 2181, Order No. 21-259, App. A at 5, 8.
[159] Docket UM 2181, Order No. 21-259, App. A at 1.
[160] PGE/2400, Bekkedahl-Tooman/6-7.

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emergencies,[161] and not all significant events result in an emergency declaration.[162] And the Commission declined to authorize deferred accounting for the significant Level III storm costs in 2017 that were not covered by the mechanism.[163] Thus, an updated Level III mechanism remains essential to allow PGE recovery of Level III costs for which an emergency is not declared and to implement and promote the Commission's safety-first policy.[164]

B. PGE's proposed changes to the Level III mechanism comply with the Commission's direction.

1. The revised mechanism appropriately allocates some risk to customers while retaining PGE's incentive to proactively mitigate risk.

The Commission instructed PGE to propose "a holistic plan that balances recovery of costs from more frequent high-impact events with incentives for investments and practices that mitigate the negative consequences from those events."[165] The mechanism should "encourage PGE to develop a robust and resilient distribution system,"[166] and PGE should continue to bear some of the risk for Level III event costs "as an incentive to invest in hardening infrastructure and implement measures that will achieve cost containment even under storm response circumstances."[167] In response to this guidance, PGE proposes sharing (90 percent to customers and 10 percent to PGE) both the costs applied to a negative Level III account balance and any positive or negative balance in the account that exceeds $12 million.[168]

Revising the mechanism to provide PGE with more reliable recovery for the costs of Level III events will not lessen PGE's commitment to increasing the resiliency of its system. PGE's

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[161] *In re Portland Gen. Elec. Co., Application for a Pre-Filed Emergency Deferral of Costs Associated with Declared Emergencies*, Docket UM 2190, Order No. 21-309, App. A at 1 (Sept. 22, 2021).
[162] PGE/2400, Bekkedahl-Tooman/6-7.
[163] Docket UM 1817, Order No. 19-274 at 13.
[164] PGE/2400, Bekkedahl-Tooman/6-7; PGE/800, Bekkedahl-Jenkins/70.
[165] Docket UM 1817, Order No. 19-274 at 14.
[166] Docket UE 335, Order No. 18-464 at 15.
[167] Docket UM 1817, Order No. 19-274 at 13.
[168] PGE/800, Bekkedahl-Jenkins/62-63.

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customer satisfaction is dependent on reliability and prompt outage restoration.[169] Therefore, PGE already restores service and responds to outage events as quickly and efficiently as possible—even when its Level III account balance had been depleted and cost recovery was not assured.[170]

Because it prioritizes safety and customer service, PGE also proactively invests in infrastructure to mitigate the impact of major events. As described in great detail in PGE's testimony, PGE's efforts are pursuant to a comprehensive, long-term plan to cost-effectively reduce risk.[171] Risk-reduction efforts include undergrounding (where appropriate), system hardening, vegetation management, smart fuses, and fault isolation schemes.[172] These efforts, and many others, are driven by PGE's commitment and responsibility to fulfill its core function as a public utility—maintaining safe, reliable power service. PGE's prioritization of these efforts will not be altered by improving the mechanism to ensure that PGE can recover the costs of responding to Level III events.[173]

Adopting PGE's revisions to the mechanism and sharing the risk between PGE and customers supports PGE's continued commitment to safety and reliability in anticipating and responding to extreme weather events. Level III response costs are prudently incurred to support public safety and welfare and meet customers' expectations, and they should be recoverable.[174] CUB agrees that "sharing cost risk with customers" is appropriate and that PGE requires better cost recovery, and CUB proposes to accomplish this by allowing the mechanism to carry a negative balance with a hard cap.[175] While PGE appreciates CUB's recognition that the current mechanism

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[169] *See* PGE/800, Bekkedahl-Jenkins/68.
[170] *See* PGE/800, Bekkedahl-Jenkins/68.
[171] PGE/800, Bekkedahl-Jenkins/57, 70-74.
[172] PGE/800, Bekkedahl-Jenkins/71-72.
[173] PGE/800, Bekkedahl-Jenkins/68.
[174] PGE/800, Bekkedahl-Jenkins/69.
[175] CUB/500, Gehrke/13 ("In recognition of the potential volatility of storm costs for PGE, and its effect on costs recovery, CUB proposed an incremental change to the mechanism to better enable PGE to recover costs, while sharing cost risk with customers and the company.").

must be revised and CUB's proposal, PGE believes that its own proposal best achieves a reasonable balance of cost sharing and caps for the balancing account.[176]

2. PGE demonstrated that event frequency, intensity, and cost are increasing.

The Commission also directed PGE to provide evidence regarding increasing storm frequency, intensity, and cost, and the impacts of climate change to justify its requested changes to the mechanism.[177] Although the parties offer different analyses and conclusions regarding the impacts of climate change, all agree that climate change is affecting storm patterns.[178] In adopting the pre-filed emergency deferral process, the Commission also has recognized the increasing incidence of a variety of emergency events.[179]

In direct testimony regarding climate change impacts, PGE explained that it has begun to experience Level III events other than winter storms.[180] PGE supported its experience with the conclusion of the Fourth National Climate Assessment, which identified significant variability, prolonged drought and heavy rainfall, overall warming, loss of snowpack, and increased wildfire risk as impacts of climate change.[181] PGE explained that these changes mean that PGE is more likely to experience high wind and rain events as well as increased risk of wildfires as a result of climate change.[182] Staff appears to agree that wildfires may increase in the future.[183]

PGE provided historical analysis demonstrating that the frequency of events has increased

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[176] PGE/1400, Tooman-Batzler/43.
[177] Docket UE 335, Order No. 18-464 at 14.
[178] *See* Staff/1400, St. Brown 9-10 ("to help PGE better recover costs in an environment of increasing frequency of storms…"); CUB/500, Gehrke/11 ("this approach fairly compensates the Company while taking into account climate change's impact on the severity of storms"); AWEC/300, Mullins/21 ("Although climate change in and of itself is certainly relevant and is likely contributing to changes in storm patterns, it has been affecting the weather for many years now."); *see also* Staff/2700, St. Brown/7 (recognizing that Level III costs could trend upwards in the future due to wildfires).
[179] Docket UM 2181, Order No. 21-259, App. A at 1-2.
[180] PGE/800, Bekkedahl-Jenkins/66.
[181] PGE/800, Bekkedahl-Jenkins/66-67.
[182] PGE/800, Bekkedahl-Jenkins/67.
[183] Staff/2700, St. Brown/7.

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from 0.48 events per year during the 1978-2008 time period to 1.75 events per year since 2014.[184] PGE also showed that 80 percent of the total Level III costs incurred over the last 27 years were incurred in just the past eight years.[185] In response to Staff's assertion that the average cost of Level III events is trending downward, PGE explained that assessing the average cost per event is not meaningful because it fails to account for the magnitude of individual events PGE has experienced.[186] In addition, both Staff's average-cost and total-cost analyses incorrectly excluded declared emergency events.[187] While PGE agrees that declared emergency events are appropriately addressed through the pre-filed emergency deferral process, rather than the Level III mechanism, the Commission must consider declared-emergency events to accurately assess increased storm frequency, intensity, and cost trends because they are Level III events.[188]

C. The current mechanism is not well suited to handle the clusters of events with increasing intensity that PGE has experienced.

PGE's analyses demonstrate that historically Level III events have occurred in clusters, meaning PGE has experienced periods with minimal event costs followed by several years with event costs.[189] The event clusters have generally increased in cost over time.[190] Because event costs are not distributed evenly across years, the 10-year average amount PGE collects from customers under the mechanism is often inadequate when a cluster of events begins.[191] For example, PGE experienced mild conditions in 2010-2013 followed by severe conditions in 2014-

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[184] Staff/1400, St. Brown/7.
[185] PGE/2400, Bekkedahl-Tooman/6. The 80 percent value includes Level III events that were declared emergencies, which is appropriate when evaluating event trends. Even excluding declared emergencies from the analysis, however, a majority of costs (57%) were incurred in the last eight years. PGE/2400, Bekkedahl-Tooman/5-6.
[186] PGE/2400, Bekkedahl-Tooman/7-8.
[187] PGE/2400, Bekkedahl-Tooman/8, 11.
[188] PGE/2400, Bekkedahl-Tooman/6.
[189] PGE/2400, Bekkedahl-Tooman/5, Figure 2.
[190] PGE/2400, Bekkedahl-Tooman/5, Figure 2.
[191] PGE/2400, Bekkedahl-Tooman/5, 8-9.

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2017, and PGE had to absorb significant costs beyond the annual accrual amount in 2015, 2016 and 2017.[192]

Recognizing that the current approach is inadequate, Staff proposes to update the 10-year average annually, rather than waiting for a rate case.[193] AWEC also appears to recognize that the 10-year average is inadequate, although AWEC nevertheless opposes changes to the mechanism.[194] While Staff's proposal would help address the event clusters, the mechanism accrual would still lag behind actual event costs and would likely be depleted during clusters of severe events. PGE's proposal to allow the mechanism balance to be negative would address this concern by providing PGE the opportunity to recover costs that exceed the reserve balance in future, milder years. Thus, PGE's proposed changes to the mechanism "appropriately allocate the risk associated with the cumulative effect of multiple years of above-average storm costs[.]"[195]

D. The Level III mechanism applies to wildfires.

CUB asserts that the Level III mechanism does not cover restoration costs for wildfire events, relying upon testimony from Docket UE 215 where the mechanism was first adopted that referred to the mechanism as a "Storm Damage Balancing Account."[196] Since its adoption, the mechanism has consistently been labeled a "Level III" mechanism, and as explained above, a Level III event is defined by its impact—not its cause.[197] While the mechanism is frequently termed a "storm" mechanism, because storms are the most common cause of a Level III outage,[198] nothing in the mechanism's origins supports CUB's effort to limit the mechanism to storm events and

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[192] Docket UM 1817, Order No. 19-274 at 13 (denying PGE's application for deferred accounting to recover the significant 2017 storm costs not covered by the Mechanism); PGE/2400, Bekkedahl-Tooman/9, n.11; PGE/1400, Tooman-Batzler/5; PGE/800, Bekkedahl-Jenkins/68.
[193] Staff/1400, St. Brown/9.
[194] AWEC/300, Mullins/21.
[195] Docket UM 1817, Order No. 19-274 at 14.
[196] CUB/500, Gehrke/14-15 (quoting Docket UE 215, Staff/400, Ball/1).
[197] PGE/800, Bekkedahl-Jenkins/60.
[198] PGE/800, Bekkedahl-Jenkins/66.

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exclude wildfires. Such a divide would likely prove difficult to implement, as many wildfires are triggered by storms, and "storm damage" could include the impacts of a wildfire.[199] For these reasons, the Level III mechanism should apply to wildfires that qualify as Level III events but are not declared emergencies eligible for deferrals. Staff agrees that the mechanism covers wildfires and also recognizes that Level III costs could trend upward in the future due to increasing wildfires.[200]

VI. DEFERRALS

The parties brought three specific deferrals into this case: The Boardman deferral, filed by AWEC and CUB, seeks to defer revenue impacts associated with the retirement of the Boardman plant on October 15, 2020.[201] The 2020 Wildfire Emergency deferral, filed by PGE, covers the impacts of the devastating Labor Day wildfires,[202] and the 2021 Ice Storm Emergency deferral, also filed by PGE, covers restoration costs following the extreme winter weather event that occurred in February 2021.[203] (Together, the Wildfire and Ice Storm deferrals are referred to as the "Emergency Deferrals.")

PGE objected that the rate case schedule and process provided inadequate time to fully address the breadth and complexity of the issues associated with these deferrals, but the Commission overruled this objection.[204] PGE's concern was borne out when the parties filed

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[199] *See* CUB/200, Gehrke/20 ("this mechanism has been designed to recover costs associated with storm damage").
[200] Staff/2700, St. Brown/7.
[201] *In re Alliance of Western Energy Consumers and Or. Citizen's Util. Board, Application for an Accounting Order Requiring Portland Gen. Elec. Co. to Defer Expenses and Capital Costs,* Docket UM 2119, Joint Application for Deferred Accounting of the Alliance of Western Energy Consumers and Oregon Citizens Utility Board (Oct. 8, 2020); Docket UE 394, AWEC-CUB/100, Mullins-Gehrke/1.
[202] *In re Portland Gen. Elec. Co., Application for Deferral of Wildfire Emergency Costs and Lost Revenues,* Docket UM 2115, PGE's Application (Sept. 10, 2020).
[203] *In re Portland Gen. Elec. Co., Application for Authorization to Defer Emergency Restoration Costs,* Docket UM 2156, Application for Deferral of Emergency Restoration Costs (Feb. 15, 2021).
[204] *See generally* PGE's Request for Certification, Response to Joint Request for Certification, and in the Alternative, Motion for Extension of Time (Nov. 18, 2021); Docket UE 394, Order No. 21-436 (Nov. 24, 2021).

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rebuttal testimony reflecting changed positions and competing proposals about how to handle the three deferrals, expanding rather than narrowing the issues in this case in their final round of testimony.[205] When it allowed the deferrals into this case, the Commission cautioned that it would not necessarily resolve all deferral-related issues and that remaining issues, "including the potential for the application of an earnings test," would be addressed in the specific deferral dockets after the close of this proceeding.[206]

PGE continues to believe that each of these three deferrals should be fully addressed outside the rate case in its own, existing docket. If the Commission decides to consider the deferrals in this case, PGE urges the Commission to deny authorization of the Boardman deferral and to delay amortization of the Emergency Deferrals until the deferrals are ripe for amortization and all information required for a complete earnings review is available. PGE also requests that the Commission reject CUB's novel and inappropriate generic proposal to reduce a utility's ROE in the future based on the amount the utility holds in deferrals.

A. Parties' positions have changed and diverged, broadening the scope of issues they seek to shoehorn into this rate case.

All parties agreed to support or not oppose approval of the Ice Storm deferral.[207] At its January 25, 2022 public meeting, the Commission approved the Ice Storm deferral,[208] meaning that both of the Emergency Deferrals are now authorized. Beyond that, parties' positions regarding the three deferrals differ widely.

1. AWEC

AWEC and CUB filed joint opening testimony supporting authorization of the Boardman

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[205] *See generally* Staff/2600, Moore-Dlouhy-Storm; AWEC/300, Mullins/2-9; CUB/400, Jenks-Gehrke/1-23; CUB/500, Gehrke/1-6.
[206] Docket UE 394, Order No. 21-436 at 4.
[207] Second Partial Stipulation at 2.
[208] Docket UM 2156, Order No. 22-020 (Jan. 26, 2022).

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deferral and advocating that the deferral be amortized over a three-year period in this case.[209] AWEC filed separate opening testimony arguing that the Emergency Deferrals should also be amortized in this case over a three-year period to offset the Boardman deferral.[210]

In rebuttal testimony, AWEC reversed its position and no longer advocates that the Boardman deferral begin amortizing in this case.[211] While AWEC apparently supports authorization of the Boardman deferral in this case, AWEC now recommends that the Commission initiate a consolidated docket to review and establish amortization schedules for all three deferrals.[212] However, AWEC also requests that in this case, the Commission approve $15 million in annual amortization related to the Emergency Deferrals, subject to refund,[213] in an apparent effort to reduce the carrying charge on the Emergency Deferrals.

2. CUB

CUB initially supported authorization and amortization of the Boardman deferral in this case but did not address the Emergency Deferrals in its opening testimony.[214] In rebuttal testimony, CUB continues to recommend amortization of the Boardman deferral in this case.[215] Regarding the Emergency Deferrals, CUB recommends that the Commission not amortize them in this case.[216] Instead, CUB asks PGE to support state legislation that would enable PGE to securitize the emergency costs.[217] CUB suggests that prudence review and amortization of the Emergency Deferrals occur in their respective dockets.[218]

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209 AWEC-CUB/100, Mullins-Gehrke/2.
210 AWEC/100, Mullins/49.
211 AWEC/300, Mullins/6.
212 AWEC/300, Mullins/6.
213 AWEC/300, Mullins/4.
214 AWEC-CUB/100, Mullins-Gehrke/2.
215 CUB/400, Jenks-Gehrke/5.
216 CUB/500, Gehrke/1.
217 CUB/500, Gehrke/3.
218 CUB/500, Gehrke/6.

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3. Staff

In opening testimony, Staff discussed why the Boardman deferral "may be necessary" but did not provide a recommendation regarding the Boardman deferral or the Emergency Deferrals.[219] In rebuttal testimony, Staff supports authorization of the Boardman deferral to "match the benefits and costs of the Boardman facility" and ensure customers do not pay for a plant that is no longer in service.[220] Staff supports reauthorization of the Wildfire deferral in this case.[221]

Staff now supports AWEC's original recommendation—which AWEC no longer supports—to amortize all three deferrals over a three-year period in this case.[222] Staff is the only party that provides a detailed recommendation regarding the earnings review process, and in so doing, acknowledges that the only amounts that could possibly be amortized at this time are those deferred in 2020 (which entirely excludes the Ice Storm deferral). Specifically, Staff proposes conducting the earnings review in three tranches, one for each calendar year, and aggregating the deferrals applicable for that year.[223] Staff recommends that PGE be allowed to amortize deferred costs or credits only to the extent PGE's earnings do not exceed or fall below 100 basis points below PGE's authorized ROE.[224] In addition, Staff recommends that PGE absorb 10 percent of the prudently incurred deferred costs for the Emergency Deferrals, but Staff does not propose sharing for the Boardman deferral.[225]

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[219] Staff/1100, Moore/15; Staff/1800, Storm/1, 8.
[220] Staff/1800, Storm/1; Staff/2600, Moore-Dlouhy-Storm/9.
[221] Staff notes that it may seek Commission approval of reauthorization prior to the close of the record in this docket. Staff/2600, Moore-Dlouhy-Storm/11. The Wildfire deferral was first authorized in 2020. Docket UM 2115, Order No. 20-389 (Oct. 27, 2020). PGE requested reauthorization in 2021. Docket UM 2115, PGE's Application for Reauthorization to Defer Wildfire Emergency Costs (Sept. 14, 2021).
[222] Staff/2600, Moore-Dlouhy-Storm/3. Although AWEC and CUB filed the Boardman deferral application on October 8, 2020 in Docket UM 2119, Staff has never responded to the filing in that docket or otherwise acted to process the deferral application. Given this history, Staff's rationale for seeking expedited authorization and amortization of the Boardman deferral now in this case is unclear. *See* Docket UM 2119.
[223] Staff/2600, Moore-Dlouhy-Storm/15.
[224] Staff/2600, Moore-Dlouhy-Storm/15.
[225] Staff/2600, Moore-Dlouhy-Storm/16-17.

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B. The Commission should decline to authorize the Boardman deferral.

Before considering amortization of the Boardman deferral, the Commission must make an initial legal determination about whether the deferral is appropriate and should be authorized.[226] The Commission has explained that the authorization analysis occurs in two steps, with the Commission first determining "whether to exercise [its] discretion to grant the application, considering the type of event that caused the request for deferral and the magnitude of that event's effect on the utility."[227] This analysis considers "the nature of the event, its impact on the utility, the treatment in ratemaking, and other factors."[228] "If the event was modeled or foreseen, without extenuating circumstances, and determined to be a stochastic event, the magnitude of harm must be substantial to warrant" authorizing the deferral.[229] The Commission has made clear that capital deferral requests "will be analyzed closely under our well-established deferral policy,"[230] which "emphasize[s] that deferred accounting treatment is appropriate only for costs or revenues that are truly *exceptional* in some way, whether due to unpredictability or magnitude, or a combination of both factors."[231]

If the Commission determines not to exercise its discretion to grant the deferral, the Commission may deny the deferral "without further consideration," or, if the Commission finds the deferral warranted, it "must then determine whether the proposed deferral is legally authorized under ORS 757.259."[232] As the proponents of the Boardman deferral, AWEC and CUB bear both

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[226] *In re Pub. Util. Comm'n of Or. Staff Request to Open an Investigation Related to Deferred Accounting*, Docket UM 1147, Order No. 05-1070 at 2-3 (Oct. 5, 2005) (explaining that a Commission decision regarding a request to defer costs involves two stages of review: (1) determination of whether the proposed deferral meets the statutory criteria, and (2) authorization to amortize deferred amounts).
[227] Docket UM 1817, Order No. 19-274 at 2.
[228] Docket UM 1817, Order No. 19-274 at 2.
[229] Docket UM 1817, Order No. 19-274 at 3.
[230] *In re Pub. Util. Comm'n of Or., Investigation of the Scope of the Commission's Authority to Defer Capital Costs*, Docket UM 1909, Order No. 20-147 at 1 (Apr. 30, 2020).
[231] *In re Util. Reform Project, Application for Deferred Accounting*, Docket UM 1124, Order No. 09-316 at 14 (Aug. 18, 2009) (emphasis original).
[232] Docket UM 1817, Order No. 19-274 at 2.

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the burden of producing evidence to support their request and the burden of persuasion.[233]

1. Boardman's closure was expected and planned for and is not exceptional or unpredictable.

CUB and AWEC have not shown that the closure of Boardman is the type of event that warrants the exceptional ratemaking treatment of authorizing deferred accounting.[234] The decision to close Boardman in 2020, instead of in 2040 as originally planned, was made and recognized by all parties in 2010.[235] This was not an unpredictable or unexpected event; the closure was planned for a decade before it occurred. During that time, PGE had three rate cases in which no party proposed a mechanism to remove Boardman from base rates.[236]

CUB argues that Boardman's 2020 closure date was exceptional because it was "a big deal for the Company," citing statements from PGE's chief executive officers about the importance of the closure for PGE's clean-energy goals.[237] However, CUB conflates the decision to close Boardman early, which occurred in 2010, with the actual closure, which occurred in 2020. While the decision to close Boardman early represented a major milestone in PGE's and Oregon's clean energy transition, as CUB notes,[238] the closure itself was expected and planned for a decade.[239] Further, CUB's interpretation of what constitutes an "exceptional" event would suggest that deferred accounting is available for any event that is important or newsworthy, rather than those that are truly exceptional and unexpected.

2. Retaining Boardman costs in rates did not result in substantial harm to customers that justifies deferred accounting.

Although PGE continued to recover for Boardman after it closed, PGE's testimony

[233]Docket UM 1817, Order No. 19-274 at 2, n.4; Docket UM 1147, Order No. 05-1070 at 5-6.
[234] *See* Docket UM 1147, Order No. 06-507 at 4 (Sept. 6, 2006) ("Deferred accounting is a discrete and *exceptional* ratemaking process…") (emphasis original).
[235] PGE/2900, Tooman-Ferchland/22-24.
[236] PGE/2300, Tooman-Batzler/17-18.
[237] CUB/400, Jenks-Gehrke/10-11.
[238] CUB/400, Jenks-Gehrke/10-11.
[239] PGE/2900, Tooman-Ferchland/22-24.

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demonstrates that the amount of regulatory lag PGE has experienced far exceeds PGE's reduced costs due to Boardman's closure.[240] Specifically, *after* factoring in the savings from Boardman and also revenue growth, PGE estimates that it absorbed almost $100 million in regulatory lag associated with new investments between the rate-effective date of PGE's last rate case in docket UE 335 (January 1, 2019) and the effective date of rate base in this case (April 30, 2022).[241] Thus, customers have not experienced substantial harm as a result of leaving Boardman in rates, and a deferral is not warranted.

The Commission has recognized that "under traditional ratemaking, a utility continues to recover a return of and return on the plant balances included in rate base during its last rate case, even though the value of the assets has depreciated since the case. Normally this benefit to the utility is countered to some extent by the fact that the utility continues to make capital investments that are not placed into rates during that period."[242] Here, the benefit of leaving Boardman in rates until this rate case was *more than* offset by PGE's continued capital investments that will not enter rates until the rate-effective date of this case. Nevertheless, reduced costs from the closure of Boardman, along with load growth and rigorous management of O&M costs, allowed PGE to absorb significant regulatory lag associated with new plant investments and delay filing this rate case as long as possible.[243] PGE based its planning for when to file this rate case on its understanding that Boardman costs, other than decommissioning costs, would remain in base rates until the effective date of new rates in this case, in accordance with normal ratemaking practices.[244]

CUB attempts to distinguish the regulatory lag PGE experienced for other capital

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[240] PGE/2300, Tooman-Batzler/14-15; PGE/2900, Tooman-Ferchland/15.
[241] PGE/2900, Tooman-Ferchland/14-15.
[242] Docket UM 1909, Order No. 20-147 at 13.
[243] PGE/2300, Tooman-Batzler/14-15.
[244] PGE/2300, Tooman-Batzler/18.

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investments, such as computers or transformers, from the costs PGE saved related to the closure of the Boardman plant during the same time period.[245] CUB argues that regulatory lag for non-generation plant should not be considered in determining whether it is fair and reasonable for PGE to retain the temporary cost-savings associated with the retirement of a generation plant until rates are reset.[246] CUB does not explain why it makes sense to treat major generating plant and all other plant in rate base differently.[247] As discussed below, the Commission considers the fairness of PGE's rates as a whole, not on an asset-by-asset basis.

3. PGE's rates have remained fair, just, and reasonable, even though Boardman is no longer in service.

CUB argues that leaving Boardman in rates after its retirement is unfair and suggests that doing so may violate Oregon's "used and useful" statute.[248] CUB states that utilities cannot earn a return on capital investments that are no longer providing service.[249] The Commission has been clear, however, that if utility rates are just and reasonable, not discriminatory, and not confiscatory, they are legal even if the rates include depreciation expense and a return for a retired plant.[250] As explained above, PGE's rates remain just and reasonable because the amount of Boardman depreciation and return in rates is more than offset by PGE's rate base investments not yet in rates.[251] The interpretation for which CUB advocates would be unworkable in practice, because utilities would be required to change their rates every time they replace a transformer or pole.

Parties also argue that PGE's new renewable resources avoid regulatory lag when they are

[245] CUB/400, Jenks-Gehrke/20-21.
[246] CUB/400, Jenks-Gehrke/20-21.
[247] PGE/2900, Tooman-Ferchland/15-16.
[248] CUB/400, Jenks-Gehrke/5-6, 14, 20; Staff/2600, Moore-Dlouhy-Storm/17-18.
[249] CUB/400, Jenks-Gehrke/18.
[250] *In re the Application of Portland Gen. Elec. Co. for an Investigation into Least Cost Plan Plant Retirement*, Docket DR 10, et al., Order No. 08-487 at 21 (Sept. 30, 2008); *see also Gearhart v. Pub. Util. Comm'n of Or.*, 255 Or App 58, 94, 299 P3d 533 (2013) (affirming the Commission on this point); *Gearhart v. Pub. Util. Comm'n of Or.*, 356 Or 216, 237 n. 15, 339 P3d 904 (2014) ("the fact that rates include a component that is prohibited by statute does not necessarily mean that ratepayers have been injured.").
[251] PGE/2300, Tooman-Batzler/14-15; PGE/2900, Tooman-Ferchland/14-15.

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placed in service because they are subject to the RAC, and therefore it would be unfair to allow PGE to benefit from regulatory lag after Boardman's closure.[252] As an initial matter, even disregarding RAC-eligible Wheatridge, PGE's lag still more than offsets the Boardman costs that remained in rates after Boardman closed.[253] Further, the RAC was specifically established by law to promote the transition to renewable energy,[254] and PGE's use of an established process to recover promptly for renewable resources is not analogous to AWEC's and CUB's unprecedented Boardman deferral, which represents both a major deviation from the traditional ratemaking process and is not authorized by statute.[255]

C. It is premature to review amortization of the three deferrals in this case.

Staff recommends that the Commission amortize the three deferrals in this case.[256] To properly address amortization of each of the deferrals, the Commission must review PGE's earnings during the deferral period or a period "reasonably representative of the deferral period."[257] However, PGE's annual ROO for 2021 will not be available before the record closes in this case.[258] Although the Boardman and Wildfire deferrals cover a portion of 2020, most of the costs covered by the Boardman deferral occurred in 2021,[259] and the Wildfire deferral has continued to incur costs into 2022.[260] The Ice Storm deferral did not begin until 2021.[261] Therefore, reviewing PGE's 2020 earnings would not be "reasonably representative of the deferral period" for any of the

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[252] AWEC-CUB/100, Mullins-Gehrke/2; Staff/1800, Storm/3-4; CUB/400, Jenks-Gehrke/14.
[253] PGE/2300, Tooman-Batzler/14-16. As explained in this testimony, for illustrative purposes, PGE deducted the Wheatridge revenue requirement when determining the net amount of lag that occurred following Boardman's closure.
[254] *See* ORS 469A.120.
[255] PGE/2300, Tooman-Batzler/17.
[256] Staff/2600, Moore-Dlouhy-Storm/3.
[257] OAR 860-027-0300(9).
[258] PGE/2300, Tooman-Batzler/9.
[259] PGE/2300, Tooman-Batzler/10.
[260] PGE/2900, Tooman-Ferchland/28.
[261] PGE/2900, Tooman-Ferchland/25.

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deferrals.[262]

Recognizing that the Commission does not have sufficient information to fully address amortization, Staff recommends that the Commission conduct the earnings review in three tranches, one for each calendar year, and begin by authorizing amortization of the amounts deferred in 2020 now.[263] PGE does not believe that considering amortization for 2020 in isolation adheres to the requirement to conduct an earnings review that is "reasonably representative of the deferral period," for any of the three deferrals,[264] nor will a piecemeal approach allow a comprehensive determination of the rate impacts of each deferral, based on the amount to be amortized and the length of the amortization period.[265] In addition, while Staff's proposal appears designed to attempt to reduce the carrying charges on the entire deferral balances, this is an incorrect interpretation of the Commission's policy. The Commission applies a lower rate after amortization has been approved because "the amortized amount differs from an investment in terms of the risk associated with it."[266] That is, as long as the unamortized balance is at risk of recovery (i.e., the balance is still subject to a prudence review or an earnings test), then that balance should be earning interest at PGE's rate of return, not the modified blended Treasury Rate.

Therefore, PGE continues to recommend that the Commission consider amortization of the Emergency Deferrals (and the Boardman deferral if it is authorized) in each deferral's specific docket, pursuant to amortization applications PGE will file this year after the 2021 ROO is available.[267] If the Commission wishes to handle amortization of the deferrals concurrently, it can require PGE to file for amortization at the same time and set the three dockets to be resolved on

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[262] PGE/2900, Tooman-Ferchland/25-26.
[263] Staff/2600, Moore-Dlouhy-Storm/13.
[264] OAR 860-027-0300(9).
[265] PGE/2900, Tooman-Ferchland/25-26.
[266] Docket UM 1147, Order No. 06-507 at 6.
[267] PGE/2300, Tooman-Batzler/2, 7.

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the same schedule. There is no need to open a separate, consolidated docket, as AWEC suggests.[268]

Like Staff's proposal to amortize in three tranches, AWEC's recommendation that the Commission authorize $15 million in annual amortization of the Emergency Deferrals subject to refund is premature and would result in a piecemeal approach.[269] AWEC seeks to reduce the carrying charges on the Emergency Deferrals (but not the Boardman deferral), while also delaying a full consideration of amortization to a separate docket.[270] However, ordering amortization subject to refund should not reduce the interest rate on the deferral balance. As explained above, a reduction in carrying charge occurs only after the utility is assured of cost recovery. If the amortized amount is subject to refund, then the risk of non-recovery has not been reduced, and the interest rate also should not be reduced. Because it would not have the intended effect, is an asymmetrical proposal, and would result in a piecemeal earnings review, AWEC's approach should be rejected.

PGE notes that delaying the amortization would potentially allow consideration of CUB's suggestion regarding securitization of the Emergency Deferrals.[271] CUB recognizes that this would require new legislation.[272] While PGE is generally supportive of the concept of securitization and appreciates the benefits this approach would provide to its customers, new legislation may not be in place before the close of the record or the Commission's decision in this case.[273]

D. If an earnings review occurs in this case, the Commission should reject Staff's

[268] AWEC/300, Mullins/6.
[269] AWEC/300, Mullins/4.
[270] AWEC/300, Mullins/4, 6.
[271] CUB/500, Gehrke/3.
[272] CUB/500, Gehrke/3.
[273] PGE/2900, Tooman-Ferchland/10.

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proposed earnings test benchmark and sharing requirements.

Staff advocates that the earnings test for each of the three deferrals should compare PGE's earnings with a benchmark of 100 basis points below PGE's authorized ROE.[274] Specifically, PGE would be allowed to amortize deferred costs only to the extent the amortization does not drive PGE's earnings above this benchmark and to amortize credits only to the extent amortization does not drive earnings below this benchmark.[275] PGE disagrees that 100 basis points below ROE is the appropriate benchmark. Staff's proposal ignores recent precedent for PGE and other utilities in which the utility's authorized ROE, or in one instance the utility's authorized rate of return, served as the benchmark in an earnings review.[276] Staff's proposal is also asymmetric in that it applies the same below-ROE threshold for amortizing credits and costs. This is inconsistent with the Commission's prior statement that an "earnings test works to protect both the utility and its customers."[277] PGE notes that 100 basis points below ROE equates to approximately $39 million for PGE, which is a significant amount to require the Company to absorb, particularly when combined with Staff's sharing proposal discussed below.[278]

PGE believes that using its authorized ROE as the benchmark provides a reasonable and consistent standard that will be predictable and fair for both the Company and its customers.[279] The Commission has previously determined that PGE's authorized ROE of 9.5 percent represents an appropriate level for both customers and the Company,[280] and in this case, parties stipulated to

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274 Staff/2600, Moore-Dlouhy-Storm/15.
275 Staff/2600, Moore-Dlouhy-Storm/15.
276 Docket UE 215, Order No. 10-478, App. B at 4; *In re Nw. Nat. Gas Co., dba NW Nat., Mechanism for Recovery of Environmental Remediation Costs*, Docket UM 1635, et al., Order No. 15-049 at 12-13 (Feb. 20, 2015); *In re Portland Gen. Elec. Co., Schedule 149, Environmental Remediation Costs Recovery Adjustment*, Docket UE 311, et al., Order No. 17-071, App. A at 6 (Mar. 2, 2017); *In re Idaho Power Co. Request to Amortize in Rates Deferred Revenues Associated with the Langley Gulch Power Plant*, Docket UE 382, Order No. 20-374, App. A at 3 (Oct. 27, 2020).
277 Docket UM 1635, Order No. 15-049 at 12.
278 PGE/2900, Tooman-Ferchland/20.
279 PGE/2900, Tooman-Ferchland/18.
280 Docket UE 335, Order No. 19-129 at 4, 11 (Apr. 12, 2019).

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maintain PGE's authorized ROE at 9.5 percent and filed testimony explaining the factors that support this as a reasonable level of earnings.[281] Staff has not explained why the earnings review should apply a different threshold.

Staff also recommends that PGE be required to absorb 10 percent of the prudently incurred deferred costs in the Emergency Deferrals, such that only 90 percent of the deferred amounts would be subject to the earnings test.[282] Staff does *not* recommend sharing for the Boardman deferral.[283] Staff reasons that applying sharing to the Emergency Deferrals incents PGE to manage costs, whereas applying sharing to the Boardman deferral incents PGE to retain Boardman in rates.[284]

PGE disagrees that sharing is appropriate for the Emergency Deferrals. The Commission rejected a similar Staff proposal for 90/10 sharing in a case where there was "limited discretion in the work the company [wa]s being required to do," finding that application of the earnings test provided "sufficient incentives . . . to minimize expenses."[285] Here, PGE was required to do a significant amount of work in a limited period of time following severe events that significantly impacted its system, and PGE does not have discretion to halt or forego recovery and restoration efforts. The Commission recognized this dynamic in its recent order adopting PGE's analogous pre-filed emergency deferral account, in which the Commission stated, "the deferred balance is subject to *full utility* recovery, pending a prudence review."[286]

E. The costs in the Emergency Deferrals are prudent and appropriate.

The parties have not raised any major prudence challenges to the costs in the Emergency

[281] First Partial Stipulation; Stipulating Parties/100, Muldoon-Gehrke-Mullins-Bieber-Chriss-Ferchland/3.
[282] Staff/2600, Moore-Dlouhy-Storm/16-17.
[283] Staff/2600, Moore-Dlouhy-Storm/17.
[284] Staff/2600, Moore-Dlouhy-Storm/17-18.
[285] Docket UM 1635, Order No. 15-049 at 11.
[286] Docket UM 2190, Order No. 21-309 at 3 (emphasis added).

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Deferrals.[287] Staff and AWEC both challenge a few specific items included in the Emergency Deferrals,[288] but these costs represent a very small portion of the deferrals ($269 for the Wildfire deferral and $55,000 for the Ice Storm deferral).[289] Contrary to Staff's and AWEC's position, the miscellaneous costs are incremental to costs in base rates and directly attributable to the emergency events.[290]

AWEC also questioned whether the costs PGE is including in the Wildfire deferral are related to the 2020 event, noting that PGE continues to incur costs more than a year after the event "which may not be appropriately tied to the 2020 wildfire event."[291] AWEC's assumption that the work is unrelated to the 2020 wildfire emergency is incorrect. In fact, PGE continues recovery work in burned areas, including removal of tens of thousands of burned trees.[292] Completion of these efforts has been hampered by weather and availability of qualified tree removal personnel, but the work does relate to the 2020 wildfire.[293]

F. CUB's proposal to adjust ROE is not applicable to the current docket and inappropriate in any case.

CUB provides significant testimony detailing its concerns regarding single-issue ratemaking in general and PGE's use of deferrals in particular.[294] CUB claims that use of deferrals reduces a utility's risk and that shareholder returns should be adjusted downward to account for

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[287] *See* Staff/2600, Moore-Dlouhy-Storm/20; AWEC/300, Mullins/8-9. CUB notes that the Commission has not conducted a prudence review, implying that CUB could be waiting to raise any prudence issues until a subsequent proceeding. CUB/500, Gehrke/3, 5-6. This supports PGE's position that it is premature to amortize the Emergency Deferrals at this time.
[288] Staff/2600, Moore-Dlouhy-Storm/20; AWEC/300, Mullins/8-9.
[289] PGE/2900, Tooman-Ferchland/27. PGE agreed with AWEC's and Staff's recommendation that labor loadings and allocations are inapplicable for these deferrals, with the exception of payroll tax loading. PGE/2900, Tooman-Ferchland/27.
[290] PGE/2900, Tooman-Ferchland/27.
[291] AWEC/300, Mullins/8-9.
[292] PGE/2900, Tooman-Ferchland/28.
[293] PGE/2900, Tooman-Ferchland/28.
[294] CUB/100, Jenks/8-13; CUB/400, Jenks-Gehrke/1-5.

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this reduced risk.[295] Specifically, CUB recommends adjusting ROE downward by five basis points for every one percent of a utility's revenue requirement held in deferrals.[296] CUB also claims that AACs result in reduced risk and stabilized earnings for the Company that should be reflected in its ROE.[297]

As an initial matter, CUB confirms that its testimony discusses policy issues generally and not PGE's revenue requirement or ROE in this proceeding.[298] PGE's ROE was the subject of a stipulation in this case that CUB supported,[299] and continues to support.[300] It appears that CUB envisions its proposal would apply to PGE—and presumably other utilities—in future rate cases. PGE's rate case is not the appropriate docket in which to adopt new, generic policy. Even if CUB's proposal would apply only to PGE, it would not apply until "the time of a future general rate case."[301] CUB's proposal is procedurally flawed, and the Commission should reject it on this basis.

In addition, CUB's proposal is duplicative of existing customer protections. The legislature required that the Commission apply an earnings test to ensure that amortization of deferrals does not allow a utility to over-earn.[302] In addition, the Commission has specifically considered and implemented a framework for addressing business risk in the deferral review process. In Docket UM 1147, the Commission set forth principles for evaluating whether to grant a deferral application, based on the type of risk (stochastic or scenario) of the event triggering the deferral.[303] While most of PGE's deferrals do not implicate *any* business risk because they simply

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[295] CUB/100, Jenks/13; CUB/400, Jenks-Gehrke/2.
[296] CUB/100, Jenks/13; CUB/400, Jenks-Gehrke/2.
[297] CUB/400, Jenks-Gehrke/4.
[298] CUB/400, Jenks-Gehrke/2.
[299] Stipulating Parties/100, Muldoon-Gehrke-Mullins-Bieber-Chriss-Ferchland/3.
[300] CUB/400, Jenks-Gehrke/2 ("CUB supports the stipulation that establishes the ROE.").
[301] CUB/400, Jenks-Gehrke/2.
[302] ORS 757.259(5).
[303] Docket UM 1147, Order No. 05-1070 at 6-7.

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implement existing Commission-approved mechanisms or policies,[304] those that do will be analyzed under the Commission's existing framework, which takes the level of business risk into account. CUB's proposal to address the utility's business risk related to deferrals a second time, by lowering ROE, is cumulative and unnecessary in light of these existing policies.

CUB's proposal is also one-sided in that CUB focuses only on the risk-reducing aspects of deferrals and AACs, without accounting for the risk-increasing aspects. One of PGE's primary AACs is its Power Cost Adjustment Mechanism, and ratings agencies and analysts have specifically noted that this AAC adds to PGE's risks and earnings volatility because of its asymmetry and cost-recovery limitations.[305] Yet the Commission has not increased PGE's ROE as a result.[306] As another example, the Oregon RPS required changes to PGE's generation portfolio, which increased PGE's risk, but then mitigated this risk by mandating cost recovery through an AAC.[307] CUB's premise that all deferrals and AACs reduce shareholder risk does not take into account the inherent risks in the legislative mandates to which many of these deferrals and AACs are tied.[308]

VII. SCHEDULE 150 NONBYPASSABILITY

PGE's Schedule 150 currently collects a charge to support transportation electrification in accordance with Section 2(2) of House Bill (HB) 2165.[309] These costs are allocated to all customers, including direct access customers, using the same methodology PGE would use to

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[304] *See* PGE/2900, Tooman-Ferchland/3-5.
[305] PGE/2900, Tooman-Ferchland/7.
[306] PGE/2900, Tooman-Ferchland/7.
[307] PGE/2900, Tooman-Ferchland/8.
[308] CUB/400, Jenks-Gehrke/2.
[309] *See PGE Advice No. 21-26, Schedule 150 Transportation Electrification Cost Recovery Mechanism* (approved Dec. 28, 2021). Available at: https://assets.ctfassets.net/416ywc1laqmd/bAlUAOkBjG2ttYMFzDBzQ/0ec1c4e2906b245a2bec5dfd2eda5fd7/Sched_150.pdf.

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allocate the costs to a cost-of-service customer of similar size and load profile.[310] PGE proposes expanding Schedule 150 to allow it to recover additional costs associated with transportation electrification not otherwise included in customer prices.[311] This would ensure that PGE recovers the costs associated with these public policy measures from all customers, including long-term and new load direct access customers, consistent with the rate spread methodology in PGE's current Schedule 150.[312]

Staff supports PGE's request.[313] However, AWEC disputes that any portion of Schedule 150 should be allocated to direct access customers, asserting that utility costs should be assigned based on principles of cost-causation and benefits received and that PGE has identified no benefits that accrue to direct access customers from PGE's transportation electrification efforts.[314] While Calpine agrees that new load direct access and long-term direct access customers should pay a share of Schedule 150 costs, Calpine takes issue with PGE's proposed cost allocation. Calpine argues that deferred costs under Schedule 150 should be recovered from customers similar to the recovery of distribution costs.[315]

PGE's proposed Schedule 150 charges should be allocated to all users of the system, including direct access customers. When large nonresidential customers choose to purchase energy from an alternate electricity supplier, the Commission must protect all customers by ensuring that customers departing PGE's supply service pay their fair share of system costs,

[310] Schedule 150 adjustment rates are created for each schedule using applicable schedule's forecasted energy on the basis of an equal percent of revenue applied on a cents per kWh basis to each applicable rate schedule, with long-term opt out and new load direct access customers priced at the equivalent cost of service rate schedule.
[311] *See, e.g.*, *In re Portland Gen. Elec. Co., Application for Deferred Accounting for Costs and Revenues Associated with the Transportation Electrification Plan,* Docket UM 1938; *In re Portland Gen. Elec. Co., Application for Deferral of Costs and Revenues Associated with the Elec. Vehicle Charging Pilots,* Docket UM 2003.
[312] PGE asks the Commission to approve its proposed schedule in this rate case and revisit these issues as appropriate in Docket UM 2024.
[313] Staff/1700, Shierman/24.
[314] AWEC/200, Kaufman/55.
[315] Calpine/100, Higgins/4.

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including costs related to public policy directives. Under SB 1149, investments expended to achieve public policy goals mandated by the legislature are costs borne on behalf of all Oregonians and are recoverable from all customers in rates.[316]

The additional transportation electrification costs PGE seeks to add to Schedule 150 fall squarely within the category of costs the Commission has deemed to benefit all customers.[317] PGE's transportation electrification efforts support statewide decarbonization goals and long-term load-growth through acceleration of electric vehicle adoption.[318] The Commission and the Oregon legislature acknowledge the benefits transportation electrification provides to Oregonians, including climate-change mitigation and improved public health and safety.[319]

In HB 2165, the legislature specifically recognized that direct access customers should contribute to transportation electrification investments. HB 2165 requires utilities to collect a monthly meter charge from *all customers* served by the utility's distribution system—regardless of whether the customer purchases energy from the utility—and to expend the funds to "support and integrate transportation electrification."[320] While Schedule 150 covers Commission-approved deferred costs associated with PGE's pilot program for transportation electrification,[321] the same principles should apply to all transportation electrification costs.

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[316] ORS 757.607(1) (prohibiting unwarranted cost shifting).
[317] *See, e.g.*, *In re Portland Gen. Elec. Co., Advice No. 20-09 (ADV 112), Schedule 136 Cost Recovery Mechanism*, Docket UE 380, Order No. 20-173 at 2 (May 28, 2020) (concluding the Community Solar Program is a legislatively-mandated program intended to provide for broad public, customer, and community benefits such that all customers should contribute to the recovery of program costs and adopting PGE's proposed cost-allocation methodology for start-up costs as an interim cost-allocation methodology while Docket UM 2024 is pending).
[318] PGE/1200, Macfarlane-Tang/44-45.
[319] *See, e.g.*, *In re Rulemaking Regarding Transportation Electrification Plans*, Docket AR 609, Order No. 19-134 (Apr. 16, 2019) (discussing legislature's broad findings in support of transportation electrification).
[320] Oregon House Bill 2165 (2021). Available at: https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2165/Enrolled; *In re Pub. Util. Comm'n of Or., Investigation of Transportation Electrification Investment Framework*, Docket UM 2165, Order No. 21-484, App. A (Dec. 27, 2021) ("HB 2165 directs each utility to implement a monthly meter charge equal to 0.25 percent of total revenues as a dedicated funding source for TE investments.").
[321] Docket UM 2003(2), Order No. 21-132 (May 4, 2021).

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As noted above, PGE proposes allocating all transportation electrification costs under Schedule 150 using Schedule 150's current allocation methodology. The Commission authorized this methodology for the allocation of transportation electrification costs under HB 2165 and should do so here.[322] Following the cost-causation principles in rate design, these costs should be allocated to customers on the equal percentage base of a customer's total energy bill.[323] PGE asks the Commission to approve PGE's proposed Schedule 150 in this case, recognizing that the Commission expects to revisit these issues in the future in Docket UM 2024, the Commission's current direct access investigation.

VIII. SCHEDULE 90 SUBTRANSMISSION RATE

In this GRC, PGE has proposed lowering the eligibility threshold for Schedule 90 customers from 100 aMW to 30 aMW. AWEC recommends that PGE also offer a subtransmission rate to its Schedule 90 customers.[324] A subtransmission rate is a rate for a customer who builds and owns the substation used to serve its load. AWEC notes that PGE's proposed new threshold would make the schedule available to more customers, including customers potentially interested in a subtransmission rate.[325]

PGE opposes introducing a subtransmission rate option for Schedule 90 customers in this rate case. Subtransmission raises cost and safety issues that should be addressed before PGE offers

[322] The Commission approved a nearly identical cost allocation methodology for PGE's Community Solar start-up costs, recognizing that nonbypassability issues will be revisited in the near future Docket UM 2024. *See* Docket UE 380, Order No. 20-173.

[323] The cost allocation PGE proposed is also consistent with the methodology proposed by Staff in its straw proposal in Docket AR 651. Staff proposed that "[n]onbypassable charges should be allocated to a DA customer in the same method as a COS customer of similar size and load profile." *See In re Rulemaking Regarding Direct Access Including 2021 HB 2021 Requirements*, Docket AR 651, Staff's Announcement for the January 26, 2022 Workshop (Jan. 12, 2022). While the Commission has not formally adopted any rules in that proceeding, Staff's proposal is consistent with the cost allocation approved by the Commission in Order No. 20-173 and serves as an appropriate interim cost allocation methodology until Dockets AR 651 and UM 2024 are complete.

[324] AWEC/200, Kaufman/50. Staff has indicated its support for AWEC's proposal. Staff/2700, St. Brown/18. No other party takes a position on this issue.

[325] AWEC/200, Kaufman/50-51.

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this rate to a wider array of customers. PGE would note at the outset that the demand for a Schedule 90 subtransmission rate is unclear. PGE currently offers a subtransmission rate for its largest customers under Schedule 89, yet only five legacy customers have elected the option.[326] Indeed, no new subtransmission services have been initiated under that schedule in the last 16 years.[327]

Even if meaningful customer uptake is possible, offering a subtransmission rate can lead to negative consequences. As noted above, a customer on a subtransmission rate builds and owns the substation used to serve its load. While a customer-owned substation must comply with minimum safety standards when it is initially built, there is currently no requirement for customers to upgrade their substations as safety standards change or the grid evolves.[328] Moreover, PGE has experienced a number of issues with legacy subtransmission customers where the customer has failed to properly maintain a substation or neglected meaningful safety issues.[329]

Offering a Schedule 90 subtransmission rate could also create upward price pressure on other customer classes. A subtransmission customer typically bypasses distribution substations and pays about half the distribution rates paid by customers served by secondary and primary service.[330] If a Schedule 90 customer were to go to direct access, the resulting revenue deficiency from loss of distribution charges would require additional fixed costs to be allocated to non-participating customers.[331] PGE believes this cost-shifting is an unintended consequence that the Commission must consider before PGE offers a subtransmission rate.

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[326] PGE/3000, Macfarlane-Tang/21.
[327] PGE/3000, Macfarlane-Tang/21.
[328] PGE/3000, Macfarlane-Tang/22-23.
[329] PGE/3000, Macfarlane-Tang/22.
[330] PGE/3000, Macfarlane-Tang/23; *see In re Portland Gen. Elec. Co. Application for Approval to Lease Property to Siltronic Corp.*, Docket UP 224, Order No. 05-966 (Aug. 29, 2005) (noting loss of anticipated utility revenue as a result of PGE's leasing of subtransmission facilities and providing subtransmission rate to customers and accepting Staff's recommendation that PGE hold remaining customers harmless from resulting revenue loss).
[331] PGE/3000, Macfarlane-Tang/23.

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Given these significant issues, PGE does not support offering a subtransmission rate to Schedule 90 customers at this time. PGE will commit to studying this issue further and addressing it in a future rate case.

IX. CONCLUSION

PGE respectfully requests that the Commission approve the specific recommendations outlined in this prehearing brief. By doing so, the Commission can support PGE's efforts to meet the challenges of climate change, advance the imperative of achieving an emissions-free energy supply, and maintain safe and reliable service at reasonable rates for customers.

Dated February 7, 2022

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**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

UE 394

PORTLAND GENERAL ELECTRIC COMPANY

**Attachment 1 to
PGE's Prehearing Brief**

Table 1 – Estimated Effect on Consumers' Total Electric Bills 2022

February 7, 2022

TABLE 1
PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS
2022

		Forecast SSEP21E22		TOTAL ELECTRIC BILLS				
				CURRENT	PROPOSED	Change		
CATEGORY	RATE SCHEDULE	CUSTOMERS	MWH SALES	w/ Sch. 125, 122, 131, 146	w/ Sch. 125, 122, 131, 146	AMOUNT	PCT.	
Residential	7	808,245	7,569,338	$1,020,069,425	$1,091,553,196	$71,483,772	7.0%	
Employee Discount				($1,134,426)	($1,212,920)	($78,494)		
Subtotal				$1,018,934,999	$1,090,340,277	$71,405,278	7.0%	
Outdoor Area Lighting	15	0	13,922	$3,106,716	$3,273,016	$166,300	5.4%	
General Service <30 kW	32	94,547	1,588,439	$195,964,504	$210,449,742	$14,485,238	7.4%	
Opt. Time-of-Day G.S. >30 kW	38	376	27,371	$3,777,957	$3,963,804	$185,847	4.9%	
Irrig. & Drain. Pump. < 30 kW	47	2,644	19,423	$4,028,637	$4,219,561	$190,925	4.7%	
Irrig. & Drain. Pump. > 30 kW	49	1,449	62,083	$9,442,136	$10,233,690	$791,554	8.4%	
General Service 31-200 kW	83	11,463	2,870,308	$282,173,850	$293,031,382	$10,857,532	3.8%	
General Service 201-4,000 kW								
Secondary	85-S	1,190	2,074,462	$177,327,853	$175,690,762	($1,637,091)	-0.9%	
Primary	85-P	171	570,537	$45,156,161	$44,840,492	($315,669)	-0.7%	-0.9%
Schedule 89 > 4 MW								
Secondary	89-S	3	95,807	$6,669,264	$6,654,699	($14,565)	-0.2%	
Primary	89-P	15	639,544	$43,512,645	$43,632,446	$119,801	0.3%	
Subtransmission	89-T/75-T	5	51,499	$4,258,038	$4,356,520	$98,482	2.3%	0.4%
Schedule 90	90-P	6	2,827,139	$177,027,286	$174,748,998	($2,278,287)	-1.3%	
Street & Highway Lighting	91/95	185	43,876	$9,856,127	$10,465,928	$609,800	6.2%	
Traffic Signals	92	0	2,576	$225,812	$190,779	($35,034)	-15.5%	
COS TOTALS		920,299	18,456,323	$1,981,461,984	$2,076,092,096	$94,630,112	4.8%	
Direct Access Service 201-4,000 kW								
Secondary	485-S	224	493,315	$12,032,279	$9,669,484	($2,362,795)	-19.6%	
Primary	485-P	55	341,815	$7,487,635	$5,797,590	($1,690,045)	-22.6%	-20.8%
Direct Access Service > 4 MW								
Secondary	489-S	0	0	$0	$0	$0		
Primary	489-P	16	1,057,666	$20,763,617	$11,973,847	($8,789,769)	-42.3%	
Subtransmission	489-T	3	266,569	$1,642,942	$1,469,629	($173,313)	-10.5%	-40.0%
New Load Direct Access Service > 10MW								
Primary	689-P	1	37,473	$589,378	$496,297	($93,081)	-15.8%	-15.8%
DIRECT ACCESS TOTALS		299	2,196,838	42,515,851	29,406,847	($13,109,004)		
COS AND DA CYCLE TOTALS		920,598	20,653,161	$2,023,977,835	$2,105,498,943	$81,521,108	4.0%	