ORDER NO. 22-129

ENTERED Apr 25 2022

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 394

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Request for a General Rate Revision.	ORDER

DISPOSITION: FIRST, SECOND, THIRD, AND FOURTH PARTIAL STIPULATIONS ADOPTED; APPLICATION FOR GENERAL RATE REVISION APPROVED AS REVISED

I. SUMMARY

This order addresses Portland General Electric Company's (PGE's) request for a general rate revision. Overall, we approve an increase to PGE's revenue requirement of approximately $10 million, representing a 0.5 percent increase from the company's previous rates. In its initial filing, PGE sought an increase of $59 million, or approximately 2.9 percent. In this order, we address disputes regarding the Level III outage mechanism, a future process to address the Faraday repowering project (Faraday project), wildfire mitigation and vegetation management cost recovery, major deferrals associated with the Labor Day 2020 wildfire, retirement of the Boardman generating facility, and the February 2021 ice storm, cost allocation for Schedule 150, and a Schedule 90 subtransmission rate. We also address the four partial stipulations resolving issues including the cost of capital, the revenue decoupling mechanism, load forecast, rate spread, rate design, and the revenue requirement.

As a result of changes to general rates, as well as changes to Schedules 138 (Energy Storage Cost Recovery Mechanism), Schedule 150 (Transportation Electrification Cost Recovery Mechanism), and Schedule 146 (Colstrip Power Plant Operating Life Adjustment) customers will experience an increase on their bills effective May 9, 2022, with residential customers experiencing an average bill increase of approximately 3.6 percent.

II. BACKGROUND AND PROCEDURAL HISTORY

On July 9, 2021, PGE filed Advice No. 21-18 to request a general rate increase. In this proceeding, we investigated the propriety and reasonableness of the proposed tariffs. Staff of the Public Utility Commission of Oregon (Staff); the Alliance of Western Energy Consumers (AWEC); Calpine Energy Solutions, LLC (Calpine); Fred Meyer Stores and Quality Food Centers, divisions of The Kroger Co. (Fred Meyer); the Oregon Citizens' Utility Board (CUB); Small Business Utility Advocates (SBUA); and Walmart, Inc., all participated as parties to the proceeding.[1] During the course of the investigation, parties filed testimony and exhibits.

The general public was given the opportunity to comment on PGE's filing at a public comment hearing on August 24, 2021, which was conducted online due to the COVID-19 pandemic.

On September 30, 2021, AWEC, CUB, Kroger, PGE, Staff, and Walmart filed a partial settlement stipulation (first partial stipulation) with supporting testimony resolving issues related to the cost of capital in this docket. The first partial stipulation is attached as Appendix A. No party opposed this stipulation.

On December 2, 2021, AWEC, CUB, Kroger, PGE, Staff, and Walmart filed a partial settlement stipulation (second partial stipulation) with supporting testimony and exhibits, resolving numerous revenue requirement issues. The second partial stipulation is attached as Appendix B. No party opposed this stipulation.

On January 18, 2022, AWEC, CUB, Kroger, PGE, SBUA, Staff, and Walmart filed a partial settlement stipulation (third partial stipulation) with supporting testimony and exhibits, resolving many of the remaining revenue requirement issues, as well as issues related to load forecasting, PGE's decoupling mechanism, and customer deposits for residential customers. The third partial stipulation is attached as Appendix C. The Natural Resources Defense Council (NRDC) and Northwest Energy Coalition (NWEC) object to the provision in the third partial stipulation that would terminate PGE's revenue decoupling mechanism, but do not oppose the remainder of the stipulation. No other party opposes this stipulation.

On February 7, 2022, AWEC, Calpine, CUB, Kroger, PGE, SBUA, Staff, and Walmart filed a partial settlement stipulation (fourth partial stipulation), resolving rate spread and the customer impact offset (CIO), the remaining issues related to the Trojan Nuclear Decommissioning Trust (Trojan NDT), fee-free bank card program, and numerous rate design issues. In their individual prehearing briefs, filed the same day, the stipulating

[1] The Northwest and Intermountain Power Producers Coalition intervened in this proceeding but did not file testimony or briefs.

parties each addressed their support for the fourth partial stipulation.[2] The fourth partial stipulation is attached as Appendix D. With the filing of the fourth partial stipulation, the parties identify the remaining disputed issues as the Level III outage mechanism, process for the Faraday project, wildfire mitigation and vegetation management cost recovery, major deferrals associated with the Labor Day 2020 wildfire, retirement of the Boardman generating facility, and the February 2021 ice storm, Schedule 150 cost allocation, and a subtransmission rate for Schedule 90.

On February 9, 2022, NRDC and NWEC filed a letter objecting to the provision in the third partial stipulation that would terminate PGE's revenue decoupling mechanism. NRDC and NWEC filed a petition to intervene on February 11, 2022. In a February 17, 2022 ruling, the Chief Administrative Law Judge granted NRDC and NWEC's petition to intervene with limitations, and adopted modifications to the procedural schedule to allow for response to NRDC and NWEC's objection, a reply from NRDC and NWEC, and the opportunity for oral argument.

On February 10, 2022, the Administrative Law Judge (ALJ) conducted an evidentiary hearing. The parties filed briefs on February 22, 2022, and March 2, 2022. Also on March 2, 2022, the stipulating parties filed supplemental testimony in response to NRDC and NWEC's objection. The Commission heard oral arguments on March 4, 2022, on issues regarding the process for review of the Faraday project, the Level III outage mechanism, deferrals, and Schedules 90 and 150. NRDC and NWEC filed their reply on March 11, 2022. The Commission heard oral arguments on March 17, 2022, on wildfire mitigation and vegetation management cost recovery issues and the provision of the third partial stipulation that would terminate PGE's decoupling mechanism. The ALJ issued a ruling closing the record on April 18, 2022.

III. COMPANY FILING

In its initial filing, PGE proposed an increase of $59 million, or 2.9 percent, to the company's revenue requirement. The company's filing was based on a forecasted 2022 test year. According to the company, the main drivers for the proposed increase are capital investments since the company's last rate case, wildfire mitigation and vegetation management programs, as well as increased operating costs. The capital investments in the company's filing include the new Integrated Operations Center, the Faraday project, phase one of the Advanced Distribution Management System (ADMS), as well as numerous transmission and distribution investments. PGE also proposed to remove all identifiable costs for the Colstrip coal-fired generating facility (expense and capital) from base rates, to be recovered through Schedule 146.

[2] Staff filed a separate prehearing brief addressing its support for the fourth partial stipulation on February 9, 2022.

PGE proposed a rate of return (ROR) of 6.938 percent, based on a capital structure of 50 percent equity, and 50 percent debt, with a 9.5 percent return on equity (ROE), and a 4.375 percent cost of debt.

PGE's filing included a marginal cost of service study. Additionally, PGE proposed changes to its rate design, including flattening the residential tiered rate structure and revising the basic charge for single and multi-family residences. Finally, PGE proposed an extension of its decoupling mechanism, Schedule 123, through December 31, 2025, as well as changes to expand its application to Schedules 38/538, 47, and 49/549, and allow the company to balance any amounts over the two percent limiter to future years.[3]

IV. APPLICABLE LAW

In a rate case, the Commission must take two primary steps. First, we must determine how much overall revenue the company is entitled to receive. A utility's revenue requirement is determined on the basis of the utility's reasonable and prudent costs. Second, we must allocate the revenue requirement among the utility's customer classes.[4]

In establishing a revenue requirement, we must determine: (1) the expected gross utility revenues; (2) the utility's operating expenses to provide utility service; (3) the rate base on which a return should be earned; and (4) the rate of return to be applied to the rate base to establish the return to which the stockholders of the utility are reasonably entitled.[5] Establishing these values allows us to determine the utility's reasonable costs of providing service and required revenues so that the company's rates will be set at just and reasonable levels.

As the petitioner in this rate case, PGE has the burden of proof. With respect to the deferral associated with Boardman's retirement, as the applicants who filed the deferral request, AWEC and CUB bear the burden of proof. The phrase "burden of proof" has two meanings: one to refer to a party's burden of producing evidence; the other to a party's obligation to establish a given proposition in order to succeed.[6] To distinguish these two meanings, we refer to the burden of production and the burden of persuasion.[7]

ORS 757.210 establishes the burden of proof and provides that, in a rate case, "the utility shall bear the burden of showing that the rate or schedule of rates proposed to be established or increased or changed is fair, just and reasonable." Thus, PGE must submit

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[3] Schedule 123 rate increases are subject to a two percent limiter to mitigate customer rate impacts.
[4] *See, e.g., American Can Company v. Lobdell*, 55 Or App 451, 454-55, *rev den* 293 Or 190 (1982).
[5] *See Pacific Northwest Bell Telephone Company v. Sabin*, 21 Or App 200, 205 & n 4, *rev den* (1975).
[6] *In the Matter of Portland General Electric Company's Proposal to Restructure and Reprice Its Services in Accordance with the Provisions of SB 114*, Docket No. UE 115, Order No. 01-777 at 4 (Aug. 31, 2001), *citing Hansen v. Oregon-Wash. R.R. & Nav. Co.*, 97 Or 190 (1920).
[7] *See, e.g.*, ORS 40.105; 40.115.

evidence showing that its proposed rates are just and reasonable. Once the company has presented its evidence, the burden of going forward (burden of production) then shifts to the party or parties who oppose including the costs in the utility's revenue requirement.[8] Staff or an intervenor, if it opposes the utility's claimed costs, may in turn show that the costs are not reasonable. For any change proposed by PGE that is disputed by another party, PGE still must show, by a preponderance of evidence, that the change is just and reasonable. If the company fails to meet that burden, either because the opposing party presented persuasive evidence in opposition to the proposal, or because PGE failed to present adequate information in the first place, then PGE does not prevail because it has not carried its burden of proof.[9]

V. STIPULATIONS

A. First Partial Stipulation

The first partial stipulation, filed September 30, 2021, addressed the cost of capital issues. This stipulation provides for an overall ROR of 6.813 percent, based on an ROE of 9.5 percent, a notional capital structure of 50 percent long-term debt (LTD) and 50 percent equity, and a cost of LTD of 4.125 percent. The stipulating parties submitted testimony supporting the ROE of 9.5 percent as within the ranges of estimates developed by PGE's expert and by Staff, reasonable given the continued uncertainty in economic and financial conditions due to the impacts of the COVID-19 pandemic, and consistent with the Commission's recent determination of ROE in PacifiCorp's rate proceeding. The stipulating parties explain that the agreed-upon cost of LTD of 4.125 percent incorporates lower-cost debt issued in the fourth quarter of 2020 that PGE had excluded as associated with trading losses, updates for a recent debt issuance of $400 million, and inclusion of PGE's forecasted November 2022 issuance at a rate of 3.68 percent (not prorated). The stipulating parties also agree that the settled rate would not be updated for any additional debt issuances in the near term.

B. Second Partial Stipulation

The second partial stipulation addresses numerous revenue requirement issues, summarized in Table 1, below. The stipulating parties represent that each party may not agree on the calculations, assumptions, or basis for each adjustment, but that the settled amounts represent a reasonable resolution of the issues. The adjustments are in the public interest and are consistent with rates that are fair, just, and reasonable.

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[8] *See In the Matter of the Application of Northwest Natural Gas Company for a General Rate Revision*, Docket No. UG 132, Order No. 99-697 at 3 (Nov. 12, 1999).

[9] *See In the Matter of PacifiCorp's Proposal to Restructure and Reprice its Services in Accordance with the Provisions of SB 1149*, Docket No. UE 116, Order No. 01-787 at 11 (Sep. 7, 2001).

Table 1

Adjustment	Description
Integrated Operations Center (IOC)	Total capital for the IOC will be $206.7 million, representing a reduction of $9 million, based on the underspend on the project
Level III Outage Accrual	2022 forecast of distribution operations and maintenance (O&M) expense reduced by $6,920,000 associated with removal of the February 2021 ice storm, $8 million re-established to the Level III reserve associated with the prior reduction for February 2021 ice storm,[10] and PGE will seek recovery of February 2021 ice storm costs through deferral, in docket UM 2156[11]
Working Capital	Working capital factor of 3.891 percent, representing an average of the prior three lead-lag study values
Miscellaneous Directors Expenses	Reduction to administrative and general (A&G) expenses of $150,000, resolving issues regarding board of director (BOD) expense and offsite meeting costs
First Bundled Settlement	Reduction to A&G expenses of $700,000, resolving issues regarding costs for memberships (including CAISO), and meals and entertainment
Campground Revenue	Other Revenue increased by $165,000 for campground revenue
Research and Development	No adjustment from initial filing, representing 0.825 percent of its forecasted transmission, distribution, and generation fixed O&M costs[12]

[10] The $8 million reduction to the Level III reserve for the February 2021 ice storm was not included in the company's initial deferral filing in docket UM 2156.

[11] The stipulating parties agree to either support or not oppose the deferral, with the understanding that this does not represent an agreement regarding to the prudence of the expenditures, the timing of amortization, or whether amortization would result in fair, just, and reasonable rates. At the January 25, 2022 Public Meeting, the Commission authorized the February 2021 ice storm costs deferral. *In the Matter of Portland General Electric Company, Application for Authorization to Defer Emergency Restoration Costs*, Docket No. UM 2156, Order No. 22-020 (Jan. 26, 2022). At the March 8, 2022 Public Meeting the Commission adopted Staff's recommendation to amend Order No. 22-020 to also establish a regulatory asset for PGE's undepreciated investment in plant no longer used and useful due to the ice storm. Order No. 22-075 (Mar. 11, 2022).

[12] The parties note this is consistent with the stipulation adopted in *In the Matter of Portland General Electric Company, Request for a General Rate Revision*, Docket No. UE 335, Order No. 18-464 (Dec. 14, 2018), which provided that PGE would include R&D expenses on this basis in its next three rate cases or 10 years, whichever comes first).

Trojan Nuclear Decommissioning Costs, Schedule 136	No adjustment to Schedule 136 from initial filing
Incentive-related Accumulated Deferred Income Taxes (ADIT)	Reduction to incentive related ADIT of $5,761,000, to align with the inclusion of 50 percent of incentives
Second Bundled Settlement	Reduction to capital of $10,522,085 for projects with delayed in service dates beyond the rate effective date (Beaver Modernization Project and the Excitation System Project)
Third Bundled Settlement	Reduction of rate base by $10,500,000 million, resolving fuel stock, ADIT Boardman removal, and Colstrip Smart Burn issues
Directors' Deferred Compensation Plan	Reduction to A&G expense by $203,000 for interest charges related to the Directors' Deferred Compensation Plan
Directors' and Officers' (D&O) Liability Insurance	Reduction to A&G expense by $100,000 to offset potential D&O liability insurance premium increases deemed to be associated with PGE's 2020 trading losses
Oregon Corporate Activities Tax (OCAT)	OCAT recovery included in base rates in an amount of $8,375,000,[13] OCAT deferral (docket UM 2037) to terminate on rate effective date of this rate case, PGE may update 2022 forecast in the event of certain changes to calculation methodology before rate effective date in this rate case[14]
Colstrip, Schedule 146	Schedule 146 Parts A, B, and C to be updated annually, with agreed-upon changes to tariff language PGE will vote "no" on capital investments intended to extend the life of Colstrip plant past 2025, subject to certain conditions PGE will provide the approved Colstrip O&M and capital budgets, and revenue requirement calculation

[13] Stipulating Parties/201, Muldoon-Gehrke-Mullins-Bieber-Chriss-Ferchland/5. The calculation of this figure is provided in Exhibit 203 (confidential) to the second partial stipulation.

[14] Updates may be made for calculation methodology changes for a prospective change in the OCAT legislation, OCAT rulemaking by the Oregon Department of Revenue (ODOR), a judicial proceeding, or an ODOR policy decision. If such a change occurs after the rate effective date for this GRC, PGE will be required to defer and amortize the difference in calculation methodology in full until the rate effective date of PGE's next GRC. Under the stipulation, no updates will be made to the 2022 forecast based solely on changes to input amounts.

	for parties' review by November 1 of each year or within seven business days of the approval of the budget Stipulating parties agree to support or not oppose PGE's request for deferred accounting of decommissioning costs

C. Third Partial Stipulation

The stipulating parties explain that after the first and second stipulations, the September load forecast update, and the removal of the Faraday project from PGE's revenue requirement, the remaining proposed non-net variable power cost (NVPC) revenue requirement increase was $13.5 million.[15] The stipulating parties state that during settlement conferences PGE emphasized its position that the initial filing contained a conservative revenue requirement increase, that the company has not had a general rate revision in three and a half years, and that PGE had delayed the filing in recognition of the COVID-19 pandemic and its impacts on customers. The non-company stipulating parties nonetheless believed that a reduction in revenue requirement was necessary to reflect fair, just, and reasonable rates. The stipulating parties explain that under the third partial stipulation, they agreed upon a $3.5 million reduction to PGE's remaining proposed non-NVPC revenue requirement increase, resolving all remaining revenue requirement issues[16] except issues regarding the appropriate limitations on fee-free bank card usage by small commercial customers, the funding of the Trojan NDT, and Staff's proposed holdback of $3 million associated with its proposed wildfire mitigation and vegetation management mechanism.

Together, the first three partial stipulations would result in an increase to PGE's revenue requirement of $10 million, or approximately 0.5 percent, excluding the movement of the OCAT forecast from a supplemental schedule to base rates.

Under the stipulation, PGE will remove the Faraday project from the revenue requirement for the May 9, 2022 rate effective date, with the parties free to continue litigating where rate recovery should be addressed. The stipulating parties agree this stipulation does not constitute an agreement that all capital investments in this proceeding are either prudent or imprudent and that a party may advocate for the removal of some or all of a specific plant investment from rate base that was not specifically addressed by the first two stipulations. The stipulation also provides that PGE will remove $15 million of plant investment beginning with the effective date of tariffs from this proceeding for purposes of any earnings reviews that take place between the Commission's order in this

[15] This amount excludes $8.375 million for the OCAT which is moving from a supplemental schedule to base rates under the second stipulation but does not represent an increase in revenues.
[16] The bundled revenue requirement issues are listed in Table 1 of the third partial stipulation.

case and rates are ordered in a subsequent general rate proceeding. The stipulating parties also note that the stipulation does not constitute an agreement that PGE is allowed to recover the expenses associated with Amazon Pay over the per-transaction costs associated with other digital wallet payment options.

The stipulating parties agree to use the September 2021 load forecast in this general rate case (GRC) and explain that this is consistent with the load forecast for 2022 power costs as included in PGE's November MONET update filing. The stipulating parties agree that this resolves all issues related to load forecasting.

Under the third partial stipulation, PGE's decoupling mechanism will terminate as of the rate effective date in this GRC. Any amount accrued up to that point will be subject to future amortization through Schedule 123.[17] The stipulating parties submitted testimony explaining that the decoupling mechanism partially disincentivizes PGE from pursuing the State's goal of transportation electrification (TE) and that in light of the Energy Trust's continuing role, achieving conservation will not be harmed. Additionally, under the stipulation, PGE will permanently cease the collection of customer deposits for residential customers beginning on the rate effective date of this GRC.

The stipulating parties explain that their decisions to resolve these issues by compromise were based on factors including new insight into issues from information obtained through discovery and testimony, concern about litigation risk on particular issues, and an interest in limiting exposure to unfavorable outcomes. The stipulating parties agree that rates consistent with this stipulation would be fair, just, and reasonable. Staff asserts that under its role it "considers the positions of other parties to the proceeding, balances the facts and policy considerations, and makes recommendations that protect the public interest."[18] Staff states that it performed this role in this case and supports the third partial stipulation.

Finally, under the third partial stipulation, PGE and Staff agree to work together on responses to standard data requests 57 and 58. Specifically, PGE commits to its information technology staff addressing certain data field truncation issues due to character limitations. PGE also agrees to work with Staff to provide better information on capital projects, including assisting in the development of data request language to more efficiently obtain the information needed during a GRC.

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[17] Decoupling is a full year mechanism and under the stipulation, the adjustment related to 2022 would be prorated based on the period from January 1, 2022, to the day before the rate effective date.
[18] Stipulating Parties/300, Muldoon-Gehrke-Mullins-Bieber-Chriss-Steele-Ferchland/9-10, *quoting In the Matter of the Public Utility Commission of Oregon*, Docket No. UM 2055, Order No. 20-386, Attachment A at 18 (Oct. 27, 2020).

D. Fourth Partial Stipulation

Under the fourth partial stipulation, the parties agree to resolve the remaining issues regarding the Trojan NDT with PGE returning the 2018 claim year Department of Energy (DOE) reimbursement of $2,960,544 to customers via Schedule 143 over a one-year period beginning May 9, 2022. The stipulating parties agree that PGE will fund this return using the 2020 claim year DOE reimbursement with the remainder of the 2020 claim year DOE reimbursement to be contributed to the Trojan NDT. Finally, PGE will refund the $352,098 residual balance of the Schedule 143 balancing account to customers via Schedule 143 over a one-year period beginning May 9, 2022. AWEC explains that this is consistent with its recommendation. Staff and AWEC argue that this is a just and reasonable resolution for the Trojan NDT issue.

The stipulating parties agree to a limit of $1,500 per billing cycle for non-residential customers using a credit card or other type of card and further agree that PGE may continue to offer the Fee Free Bank Card program to non-residential customers after the COVID-19 state of emergency ends. Staff explains that this agreement achieves an appropriate balance between providing convenience to customers with the need to control costs for ratepayers.

The stipulating parties also agree to settle all rate spread issues based on using the marginal cost studies filed in this case with updates to loads, forecasted natural gas prices, and cost of capital in the generation marginal cost study. Additionally, under the fourth partial stipulation, the CIO is applied to move $2.842 million from Schedule 83, $3.654 million from Schedules 85/485, $2.061 million from Schedules 89/489, and $1.2 million from Schedule 90 and apply $6.585 million to Schedule 7 and $3.177 million to Schedule 32. The agreed-upon rate spread would result in the approximate changes, set forth below.[19]

Table 2

Schedule	Change
Residential, Schedule 7	7.0 percent
General Service <30kW, Schedule 32	7.4 percent
General Service 31-200kW, Schedule 83	3.8 percent
General Service 201-400kW , Schedule 85	-0.9 percent
>4MW, Schedule 89	0.4 percent
Schedule 90	-1.3 percent
Irrigation	4.7 percent (<30kW); 8.4 percent (>30kW)

[19] *See* PGE Prehearing Brief at Attachment 1 (Feb. 7, 2022) (including impact of changes in power costs).

Streetlighting	6.2 percent
Overall COS	4.8 percent

CUB explains that it is a signatory to the fourth partial stipulation, except for the agreement regarding rate spread and the CIO, and as a signatory recommends that the Commission adopt the fourth partial stipulation. CUB explains that it neither supports nor opposes the rate spread agreement, because it prefers that rate spread stipulations align with existing Commission precedent that disallows rate decreases in the event of an overall increase.[20]

Staff explains that in reaching agreement on this issue, the parties focused on the rate increase by rate class including the following supplemental schedules: Schedule 125 (Annual Power Cost Update), Schedule 122 (Renewable Resources Automatic Adjustment Clause (RAC)), Schedule 131 (Oregon Corporate Activity Tax Recovery), and Schedule 146 (Colstrip Power Plant Operating Life Adjustment).

AWEC argues that in this case there are several compelling justifications for a rate spread that results in certain classes receiving increases while others receive decreases. AWEC contends that the rate spread is roughly consistent with PGE's cost of service study, with the application of the CIO as the only material deviation. Staff agrees, arguing that neither PGE's cost of service study nor Staff's analysis support an increase for all classes of customers. AWEC maintains that the CIO is mitigating increases for some customer classes, but that the classes receiving decreases are contributing to the CIO. Fred Meyer argues that the agreement strikes a reasonable balance between the interests of CIO-receiving and CIO-paying rate schedules. Further, AWEC argues that considering the changes, including those through supplemental schedules, no customer will receive a decrease based on overall rate changes since PGE's last GRC. AWEC notes that there is no process for addressing rate spread between GRCs, and that over three-quarters of PGE's overall rate increase since its last GRC occurred through supplemental schedules. Staff explains that the agreed-upon rate spread also ensures equitable treatment for direct access customers. Specifically, Staff notes that the rate reduction from transition charges that are no longer applicable can make large CIO contributions from these customers appear equitable based on a comparison to current rates, and the agreement accounts for this.

The stipulating parties agree to bifurcate the Schedule 7 (residential) basic charge into single and multi-family, maintaining the basic charge at $11 for single family residences

[20] CUB Prehearing Brief at 16-17 (Feb. 7, 2022), *citing In the Matter of Revised Tariff Schedules Applicable to Electric Service and the Application for Approval of Alternative Form of Regulation Plan Filed by PacifiCorp*, Docket No. UE 94, Order No. 96-175 at 5-6 (Jul. 10, 1996); *In the Matter of Portland General Electric Company, Request for a General Rate Revision*, Docket No. UE 335, Order No. 19-129 at 11 (Apr. 12, 2019).

and reducing the basic charge for multi-family residences to $8. Additionally, the stipulating parties agree to no modification to the Schedule 7 Line Extension Allowance in this proceeding. Staff supports these charges as reasonably reflecting the cost of service and resulting in just and reasonable rates. The stipulating parties also agree to the changes to temporary service proposed by PGE.[21]

Under the fourth partial stipulation, PGE will establish generation demand charges for Schedule 83 and 85, assigning 25 percent of generation to the new demand charge for each schedule. The stipulating parties agree to apply the generation demand charge directly to Schedule 483 and 485 customers during the transition adjustment period and to calculate transition adjustments for Schedules 483 and 485 as the difference between generation cost-of-service volumetric charges and market value for direct access opt-outs beginning in 2023. The stipulating parties agree that updates to fixed generation costs charged volumetrically (*e.g.*, Schedule 122 RAC updates) will apply to the transition adjustment for long-term opt-outs. Changes to fixed generation costs charged via the generation demand charge will apply directly to the demand charge. Under the fourth partial stipulation, the transition adjustment will be recalculated going forward based on the reduced volumetric charge associated with any future increases in the generation demand charge resulting from rate redesign. Finally, PGE will address the timeline for ramping in generation demand charges in its next GRC filing. Calpine contends that proper implementation of a demand charge requires changes to the transition adjustment calculations, and that the fourth partial stipulation addresses the agreed-upon method with specificity to avoid confusion in the future. Staff supports implementation of demand charges for Schedules 83 and 85 as consistent with cost causation principles and providing an incentive to customers to minimize costly peaky usage patterns.

The stipulating parties agree that changes to Habitat Restoration options, as raised by CUB, will not be addressed in this case. They agree that CUB may raise, and PGE will support consideration of these issues in docket UM 1020. The stipulating parties recognize that CUB and PGE may or may not agree on the proposal but agree to work together in good faith.

The stipulating parties agree that Schedule 137 (Solar Payment Option program costs), will be non-bypassable, consistent with PGE's proposal. Staff states that it is appropriate to spread the non-power cost portion of the program to all customers. PGE agrees to withdraw its proposal for Schedule 135 (Demand Response Cost Recovery Mechanism) to be non-bypassable, and remains free to pursue this issue in another proceeding. Additionally, PGE will revise Schedule 138 (Energy Storage Cost Recovery Mechanism) to include the following language, proposed by CUB: "expenses associated with House Bill 2193 energy storage pilots." The stipulating parties agree that PGE may propose

[21] Fourth Partial Stipulation at 4 (Feb. 7, 2022), *citing* PGE/1200, Macfarlane-Tang/47-48.

changes to energy storage-related cost recovery under schedules other than Schedule 138 in the future.

E. Positions of the Parties

1. Stipulating Parties

The stipulating parties request that the Commission adopt the partial stipulations without modification. The stipulating parties argue that the four partial stipulations represent a reasonable compromise that will result in fair, just, and reasonable rates. AWEC argues that each stipulation is the product of substantial work and negotiations by the stipulating parties and contends that adoption of the four partial stipulations will result in rates that are fair, just, and reasonable and will further the public interest. Walmart asserts that the package of four settlements represents the just and reasonable outcome of extensive arms-length negotiations conducted in good faith between the parties and is a balance of all the elements contained in those four settlements. Walmart argues that removing one of the elements from one of the settlements changes that balance. Calpine argues that it did not take a position on the issues resolved in the first three stipulations but does not oppose them. Calpine Solutions states that it is a party to the fourth partial stipulation and recommends that the Commission adopt that stipulation as a reasonable compromise of the issues addressed therein.

Staff, CUB, AWEC, Kroger, Walmart, SBUA, and PGE submitted supplemental joint testimony in response to NRDC and NWEC's objection. PGE's current decoupling mechanism, Schedule 123, was initially approved in 2009 in Order No. 09-020.[22] The stipulating parties explain that Staff, CUB, and Kroger opposed, or expressed substantive concerns regarding, the implementation of a decoupling mechanism in 2009.

In this proceeding, PGE initially proposed extending the mechanism to December 31, 2025, with modifications to allow for balancing of amounts in excess of the two percent limiter for recovery in subsequent years. The other parties opposed this change, regarding the two percent cap as a rarely invoked control to protect customers in the event of a severe recession. They explain that, given the increasing likelihood of exceeding the limiter, PGE then proposed eliminating the decoupling mechanism.

The stipulating parties state that the energy policies in Oregon have changed since the current decoupling mechanism was adopted in 2009. They explain that the original Renewable Portfolio Standard (RPS) had been recently passed by the Oregon Legislature at that time, and in the ensuing years a number of bills have been passed to carry out the goal of decarbonizing and electrifying the energy system. The stipulating parties point to

[22] *In the Matter of Portland General Electric Company, Request for a General Rate Revision*, Docket No. UE 197, Order No. 09-020 at 29-30 (Jan. 22, 2009).

SB 1547's mandate that PGE "plan for and pursue all available energy efficiency resources that are cost effective, reliable and feasible" as removing the disincentive for PGE to invest in energy efficiency. The stipulating parties agree that a legal mandate is more effective than a decoupling mechanism at removing a disincentive. The stipulating parties contend that decoupling was meant to help eliminate this disincentive and that this statutory requirement greatly diminished decoupling's importance. The stipulating parties note that they do not agree on all of the details of how to best implement this evolving policy landscape but do agree that the primary policy arguments used to justify decoupling (promotion of energy efficiency, disconnecting profits from through-put) are less valid given the evolution of legislative mandates on decarbonization, energy efficiency, and electrification in Oregon. The stipulating parties argue that due to changes in legislation and COVID-19 impacts it is reasonable to reevaluate standard mechanisms like decoupling, particularly where there are other tools to balance the sales volume, such as the Oregon legislation promoting TE.

The stipulating parties contend that decoupling could serve as a disincentive to PGE from investing in TE, which would run counter to SB 1547. They argue that PGE's incentives to undertake TE could be reduced by decoupling because decoupling means that PGE does not retain additional revenues associated with increased electricity usage from electric vehicle (EV) charging. They assert that when new EVs are added in PGE's territory, most of the charging revenue is passed back to residential customers as decoupling credits. The stipulating parties explain that because decoupling limits PGE's ability to retain the additional revenues created by EVs being added to its system, it reduces the incentive PGE has to accelerate TE.

The stipulating parties also contend that passing TE load benefits through decoupling limits the Commission's tools for cost recovery for TE expenses. The stipulating parties explain that new TE load on the system is treated differently than when a new building is connected to the system. They maintain that between rate cases, PGE retains both the cost of connecting the building to the distribution system and the revenue from that new customer. In PGE's next GRC, the investments are included in rate base and the revenue from the customer is included to offset the revenue requirement of the investment. The stipulating parties contend that when the new load is a vehicle, which is likely charged at a customer's residence, decoupling forces the revenues from that load to flow back to residential customers. The stipulating parties argue that without eliminating decoupling, as EVs become mainstream and utilities must meet the associated load, it will be hard to eliminate the use of deferrals or automatic adjustment clauses for costs between rate cases. They argue that eliminating decoupling is an administratively simple method of keeping the charging revenues with the company, avoiding the need to seek other regulatory mechanisms. The stipulating parties continue to recommend eliminating the existing decoupling mechanism, even in the event the Commission sought to evaluate the role of decoupling in light of recent legislation ordering carbon reduction and TE.

2. NRDC and NWEC

NRDC and NWEC oppose the provision in the third partial stipulation, under which PGE's decoupling mechanism would terminate on the rate effective date in this GRC. NRDC and NWEC argue that it is notable that none of the stipulating parties initially sought to eliminate revenue decoupling. They contend that PGE proposed to extend the mechanism in its initial filing, and neither CUB nor Staff opposed an extension of the existing version of the mechanism in this proceeding. NRDC and NWEC argue that, although the stipulating parties testified that they had originally opposed decoupling for PGE in 2009, they have not provided any evidence in this case in support of their recommendation to now terminate revenue decoupling for PGE. Specifically, NRDC and NWEC assert that the stipulating parties fail to provide evidence or a discussion of experience with the current decoupling mechanism in support of their three arguments for termination.

First, NRDC and NWEC dispute the stipulating parties' position that revenue decoupling is not needed because Oregon has an independent Energy Trust administering energy efficiency programs and contends that the Commission dismissed that argument when it initially adopted decoupling. Specifically, NRDC and NWEC maintain that in 2009 the Commission stated:

> We find this position unpersuasive, because PGE does have the ability to influence individual customers through direct contacts and referrals to the ETO. PGE is also able to affect usage in other ways, including how aggressively it pursues distributed generation and on-site solar installations; whether its supports improvements to building codes; or whether it provides timely, useful information to customers on energy efficiency programs. We expect energy efficiency and on-site power generation will have an increasing role in meeting energy needs, underscoring the need for appropriate incentives for PGE. [23]

NRDC and NWEC contend that the stipulating parties do not address what has changed since the Commission rejected this argument in 2009.

Second, NRDC and NWEC also dispute that the requirement in SB 1547 that PGE "plan for and pursue all available energy efficiency resources that are cost effective, reliable and feasible" on its own is sufficient to remove a strong financial disincentive, as the stipulating parties claim. NRDC and NWEC argue that the stipulating parties fail to

[23] NRDC and NWEC Reply at 2 (Mar. 11, 2022), *quoting* Order No. 09-020, at 27.

address why both should not be used together, asserting that the effectiveness of a mandate depends on many other factors that influence utility and customer behavior, including the utility's financial interests. NRDC and NWEC argue that a requirement to save energy paired with a financial disincentive is likely to result in the utility doing the bare minimum, including possibly pursuing less effective energy efficiency programs and investments.

Third, NRDC and NWEC argue that the stipulating parties fail to respond to the evidence presented in their objection. NRDC and NWEC contend that in arguing that decoupling reduces the incentive PGE has to accelerate TE, the stipulating parties disregard key provisions of SB 1547 that direct PGE to propose programs to accelerate TE, while also affording the utility a robust financial incentive to comply fully.

NRDC and NWEC contend that decoupling will enhance utility investment in TE by helping to ensure that such investments benefit all customers. NRDC and NWEC assert that PGE has supported its TE initiatives based on the argument that widespread EV charging will put downward pressure on rates for all customers. NRDC and NWEC maintain that decoupling is essential to bringing that to fruition. Specifically, they explain that decoupling will automatically return excess revenues to all utility customers from increased electricity sales due to more widespread TE. NRDC and NWEC argue that to eliminate decoupling, rather than being an "administratively simple method of keeping the electric charging revenues with the company" as the stipulating parties contend, would instead result in PGE being allowed to retain throughput-related windfall gains that otherwise would be returned to all customers.[24]

NRDC and NWEC recommend that the Commission condition its adoption of the third partial stipulation on a further extension of the decoupling mechanism. NRDC and NWEC also support a subsequent process to address whether and how the mechanism may be improved.

F. Resolution

We review the terms of a stipulation for reasonableness and accord with the public interest. We review settlements to determine whether, on a holistic basis, they serve the public interest and result in just and reasonable rates. A party may challenge a settlement by presenting evidence that the overall settlement results in something that is not compatible with a just and reasonable outcome. Where a party opposes a settlement, we will review the issues pursued by that party, and consider whether the information and argument submitted by the party (which may be technical, legal, or policy information and argument) suggests that the settlement is not in the public interest, will not produce

[24] NRDC and NWEC Reply at 3, *quoting* Stipulating Parties/304, Scala-Jenks-Mullins-Bieber-Chriss-Steele-Macfarlane/8.

rates that are just and reasonable, or otherwise is not in accordance with the law. To support the adoption of a settlement, the stipulating parties must present evidence that the stipulation is in accord with the public interest, and results in just and reasonable rates.

The stipulating parties negotiated the third partial stipulation as an integrated agreement, with give and take on numerous issues in reaching a settled result that they agree is in the public interest. We are mindful of the balance achieved between parties representing divergent interests under the stipulation. While NRDC and NWEC argue that the termination of PGE's decoupling mechanism would represent a significant policy shift, we recognize that the mechanism was adopted initially in a rate case rather than a generic policy docket and has always been temporary and subject to periodic renewal.[25] We find that termination of this mechanism in this case, rather than ordering a further extension that would leave the issues with the mechanism that PGE raised in its opening testimony unresolved, is reasonable in the overall context of the issues addressed in the third partial stipulation.

We reach this determination, however, without accepting the stipulating parties' arguments that decoupling mechanisms are ill-suited to provide incentives for electric utilities going forward, and with disappointment at the lack of meaningful opportunity for the Commission and other stakeholders to engage on important policy issues related to decoupling before the stipulating parties agreed to terminate the mechanism. Therefore, we direct PGE, in opening testimony in its next GRC, to more fully justify why the Commission should not implement a decoupling mechanism to incent electric efficiency even within a context of policy-driven electrification. The parties' arguments in this case raised numerous technical and policy questions about how decoupling might interact with energy efficiency as TE accelerates and electrification is incentivized. Given the existing legislative incentives to the company to accelerate TE, we are not convinced that flowing the revenues associated with increased TE load back to the company will be the appropriate result as TE investments increase. We find that continued examination is warranted to consider the role for decoupling as TE acceleration moves from the pilot phase to a larger scale, and broader electrification initiatives are implemented in the context of continuing energy efficiency.

In addition to revisiting this issue in PGE's next GRC, we also expect to consider the use of any increased revenues from TE in the context of future proposals for TE program-related deferrals. The stipulating parties argue that eliminating decoupling would provide

[25] Order No. 09-020 at 29-30 (tariffs initially authorized for two years); *In the Matter of Portland General Electric Company, Request for a General Rate Revision*, Docket No. UE 215, Order No. 10-478 (Dec. 17, 2010) (stipulated three-year extension); *In the Matter of Portland General Electric Company, Request for a General Rate Revision*, Docket No. UE 262, Order No. 13-459 (Dec. 9, 2013) (stipulated three-year extension); *In the Matter of Portland General Electric Company, 2017 Decoupling Adjustment, Schedule 123*, Docket No. UE 306, Order No. 16-359 (Sep. 26, 2016) (stipulated three-year extension); Order No. 18-464.

PGE with the ability to pay down fixed costs of beneficial investments under House Bill (HB) 2165 with the additional revenues collected between rate cases. We expect, under that logic, to see PGE absorb more TE investment costs between rate cases and will critically examine TE-related deferrals while PGE's decoupling mechanism is not in place.

We have reviewed the partial stipulations and supporting briefs and testimony submitted by the parties. We find the terms of the stipulations are supported by sufficient evidence, appropriately resolve the issues in this case, and will result in fair, just, and reasonable rates. We find that the stipulations, taken together, represent a reasonable resolution of the identified issues and contribute to an overall settlement in the public interest. While the parties note that the Commission has historically disfavored decreasing rates for any customer class while other classes experience increases, in this case, we recognize that the stipulating parties evaluated the rate impacts on each rate class over a longer period of time (since PGE's last GRC) and including supplemental schedules to capture the longer-term rate impact on customers from all rate changes. Over that longer time period and with that broader evaluation, we accept the parties' conclusion that no customer class would experience an overall decrease in rates. Accordingly, we adopt the four partial stipulations in their entirety.

VI. CONTESTED ISSUES

A. Wildfire Mitigation and Vegetation Management Cost Recovery

1. Introduction

In 2018, PGE implemented a wildfire mitigation program to identify locations of increased wildfire risk on its system and actions to mitigate the risk of its facilities creating or contributing to a wildfire. In March 2020, Governor Kate Brown issued Executive Order No. 20-04, which directed the Commission to evaluate the electric companies' risk-based wildfire protection plans and planned activities. Following this directive, the Commission opened a rulemaking, docket AR 638, for Risk-Based Wildfire Protection Plans and Planned Activities. In June 2021, the Oregon Legislature passed SB 762, which requires electric utilities to develop and operate under a Commission-evaluated risk-based wildfire protection plan and addresses cost recovery for "[a]ll reasonable operating costs incurred by, and prudent investments made by, a public utility to develop, implement or operate a wildfire protection plan." PGE filed its 2022 Wildfire Mitigation Plan in docket UM 2208 on December 30, 2021.

In its initial filing in this case, PGE proposed to include in rates $6.0 million in wildfire mitigation capital projects to be in service by April 2022 and $6.6 million for wildfire mitigation O&M test year expense.[26] PGE also included in its proposed rates $46.7 million for test year vegetation management O&M costs, which includes routine maintenance, the Facility Inspection and Treatment to the National Electric Safety Code (FITNES) Program, capital support, outage and storm response, enhanced vegetation management, and advanced wildfire risk reduction (AWRR). AWRR comprises $12.8 million of the $46.7 million in test year vegetation management costs.[27] PGE explains that AWRR is a new vegetation management program designed to reduce the risk of wildfire associated with vegetation near utility assets, focused on high risk wildfire zones (HRFZ).

As addressed above, in the third partial stipulation, the stipulating parties agreed to a $10 million increase to the overall revenue requirement, which resolved the then-remaining revenue requirement issues in this proceeding. They also agreed that certain issues regarding wildfire mitigation and vegetation management cost recovery would continue to be litigated, including Staff's proposal to hold back $3 million in wildfire mitigation and vegetation management expense subject to recovery under Staff's proposed performance-based mechanism.

Staff proposes a performance-based wildfire mitigation and vegetation management cost recovery mechanism similar to the one established for PacifiCorp in its 2019 GRC.[28] Under Staff's proposal, $3 million would be withheld from PGE's overall revenue requirement. PGE would be able to recover prudently incurred capital and reasonable O&M expenses for wildfire mitigation and vegetation management activities incremental to those recovered in base rates through an annual rate adjustment based on an earnings test. Specifically, the first incremental $6 million (*i.e.*, the withheld $3 million and an additional $3 million) would be recoverable subject to an earnings test, with the threshold adjusted based on PGE's vegetation management performance. Staff's proposed earnings test establishes earnings thresholds based on the number of vegetation management violations identified by Safety Staff, with additional basis point reductions from authorized ROE (AROE) for violations in HRFZs or associated with climbable trees.[29] Under Staff's proposal, if PGE's wildfire mitigation and vegetation management O&M expenses are below the amount in base rates, any amounts not incurred would be subject to deferral and returned to customers.

In its surrebuttal testimony, PGE submitted proposed Schedule 151, an automatic adjustment clause (AAC) for its incremental wildfire mitigation costs pursuant to

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[26] PGE/800, Bekkedahl-Jenkins/49-50.
[27] PGE/800, Bekkedahl-Jenkins/55.
[28] Staff/600, Dlouhy/25-32 *citing In the Matter of PacifiCorp's Request for a General Rate Revision*, Docket No. UE 374, Order No. 20-473 (Dec. 18, 2020).
[29] Staff/600, Dlouhy/26, 28-29.

SB 762.[30] Under Schedule 151, PGE would submit a deferral application with a forecast of wildfire O&M and capital spending for the following year, incremental to what is included in base rates. The wildfire mitigation costs in the deferral would be amortized through Schedule 151 over the next calendar year, subject to a determination that the costs were actually incurred, are covered by subsection 3(8) of SB 762, and are prudent. Under PGE's proposal, the recovery of these funds would not be subject to an earnings review.

Additionally, PGE states that its forecasted 2022 wildfire mitigation O&M expenses have increased to $28 million.[31] PGE states that it has not revised its revenue requirement in this GRC to account for the additional expense but indicates that it will seek to defer these expenses in docket UM 2019 and seek recovery under its proposed AAC.[32]

2. *Parties' Positions*

a. PGE

PGE urges the Commission to reject Staff's proposal and instead approve Schedule 151. PGE argues that Staff's proposal, which is similar to that adopted for PacifiCorp in docket UE 374, is no longer viable following SB 762. PGE also argues that there has been significant progress on wildfire mitigation rules and the development of wildfire mitigation plans since 2019 when PacifiCorp's mechanism was adopted and any new mechanism should reflect those changes. PGE asserts that a wildfire mitigation mechanism should focus on the efforts identified in its wildfire mitigation plan. PGE maintains that it is not appropriate to combine all wildfire mitigation and vegetation management activities and costs together and characterize them as wildfire mitigation.

PGE states that Staff's proposal would penalize it based on the number of vegetation management violations on any part of PGE's system, encouraging it to focus on activities largely unrelated to wildfire mitigation. PGE asserts that a wildfire mitigation mechanism should incentivize a utility to prioritize actions in HRFZ, which Staff's proposal does not do. Additionally, PGE argues that such a mechanism should only apply to the AWRR program and not to its vegetation management program generally. PGE also maintains that the costs should be subject to a prudence review, and the metric used for penalties should be based on confirmed vegetation management violations in PGE's HRFZs only.

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[30]PGE/3004, Macfarlane-Tang. In reply testimony, PGE's witness mentions an AAC, but the testimony does not describe or include the proposed tariff. PGE/2000, Bekkedahl-Jenkins/14-15, *referencing* PGE/2200, Macfarlane-Tang.
[31] PGE/2800, Bekkedahl-Tinker-Brownlee/5-6.
[32] *Id.*

Additionally, PGE disputes Staff's position that Staff's proposal serves necessary cost control purposes, given the increase in wildfire mitigation and vegetation management costs. PGE argues that its costs have been reviewed by the parties, who have all agreed that the costs are prudent, and there is no evidence that adopting PGE's proposal would result in imprudently incurred costs for ratepayers. Further, PGE argues that the wildfire mitigation and vegetation management costs for it and the other utilities are likely to increase in the future, but that these costs will be reviewed for prudence before they are included in rates. PGE also asserts that incremental costs recovered through its AAC would also be reviewed for prudence before they are collected through the AAC.

PGE asserts that if the Commission chooses to adopt a mechanism similar to Staff's proposal, that mechanism should only apply to incremental costs beyond what is in base rates and should not include the $3 million holdback. PGE argues that Staff has not provided evidence that PGE's vegetation management practices are deficient or any other supportable reason for a $3 million holdback. PGE also contends that Staff has not demonstrated that the company requires a new incentive to improve its vegetation management practices given the significant increase for these activities that PGE has proposed in this GRC. PGE states that Staff's proposal appears to come from PacifiCorp's last rate case, docket UE 374, and that it has not provided supporting evidence for such a mechanism in this proceeding. PGE argues that Staff's reasons are inconsistent and arbitrary and that the proposal overall is unsupported and punitive.

PGE also argues that Staff's proposal is contrary to SB 762 and that its proposed AAC would allow for dollar-for-dollar recovery consistent with the language in SB 762. PGE asserts that Staff's arguments disregard the Commission's determinations regarding ORS 469.160(2), which found that the legislature explicitly mandated dollar-for-dollar recovery for fixed capital costs. PGE states that ORS 469.160(1) permitted the recovery of all prudently incurred costs in rates and did not mandate a specific cost recovery method, while ORS 469.160(2) covered a narrower set of costs and did specifically set forth how costs should be recovered. PGE argues that ORS 757.963(8), which covers the wildfire mitigation costs PGE is seeking to recover in Schedule 151, describes both the costs that are recoverable and how those costs are to be recovered, which is directly analogous to the language used in ORS 469A.120(2).

Similarly, PGE argues that Oregon courts presume the legislature is aware of existing law when it drafts statutory language, and in this case the legal presumption is that the language in SB 762 would be interpreted as it had been for other statutes, such as ORS 469.160(2). Further, PGE argues that Staff's proposal is contrary to SB 762, because it could result in the non-recovery of prudently incurred costs and does not allow for timely recovery of costs. PGE emphasizes that, apart from the language in SB 762, the legislature has clearly expressed that wildfire mitigation spending is a state priority and argues that the Commission should encourage prudent spending to meet SB 762's goals.

In response to Staff's argument that the company did not propose the AAC until its final round of testimony, PGE states that it was not initially seeking an AAC in this rate case, but Staff's testimony urging the Commission to adopt a rate adjustment mechanism opened the door. PGE also notes that it requested that the Commission adopt an AAC as part of its reply testimony and then offered additional detail in its surrebuttal testimony. PGE argues that its proposed AAC follows a known template—in this case, the RAC—and complies with SB 762.

PGE also requests that the Commission approve its request for a deferral of the additional wildfire mitigation costs it identified during this proceeding. PGE states that it filed its 2022 Wildfire Mitigation Plan in docket UM 2019 on December 31, 2021, after this GRC was filed. PGE argues that the timing and expectations associated with developing and implementing wildfire mitigation plans necessarily requires some degree of new spending to accomplish the goals of the Oregon Legislature and the Commission. Thus, PGE states that its wildfire mitigation costs have increased, but maintains that it is not seeking recovery of those costs in this rate case. PGE states that it is instead seeking the authority to defer these additional incremental costs for a later prudence review and recovery through its proposed AAC.

b. Staff

Staff asserts that its proposed performance-based ratemaking mechanism is consistent with SB 762. Contrary to PGE's arguments, Staff maintains that ORS 757.210 is distinct from the language in ORS 469A.120(2) and does not require dollar-for-dollar recovery through an AAC. Specifically, Staff argues that ORS 757.210 refers to one category of costs while ORS 469A.120(1) and (2) each referred to different categories of costs. According to Staff, the Commission determined that while all costs related to RPS compliance were recoverable under the statute, only the utility's capital investments were recovered on a dollar-for-dollar basis.[33] Staff asserts that as phrased in ORS 757.963(8), it does not make sense that the Commission would have to conclude that the legislature specified that all costs were recoverable and in the next sentence specified that it must be dollar-for-dollar recovery under an AAC.[34]

Staff argues that there is a difference between the recovery for capital and non-capital costs, stating that under ORS 757.335 capital investments can only be recovered in rates

[33] Staff Opening Brief at 11-12 (Feb 22, 2022), *citing In the Matter of Portland General Electric Company and PacifiCorp's Request for Generic Power Cost Adjustment Mechanism*, Docket No. UM 1662, Order No. 15-408 at 6 (Dec. 18, 2015).
[34] Staff Opening Brief at 12.

after investments are put in service. Staff contends that this means that an AAC established for capital costs would require a periodically adjusted rate for plant already placed in service which would necessarily provide for dollar-for-dollar recovery. Staff argues that an AAC for non-capital costs does not necessarily require dollar-for-dollar recovery and that there have been previous AACs that do not require dollar-for-dollar recovery, such as those updating rates based on an O&M forecast. Staff argues that a forecast-based AAC would be consistent with SB 762 without requiring dollar-for-dollar recovery. Additionally, Staff states that an Attorney General opinion determined the Commission was only authorized to adopt AACs that did not incorporate previously incurred costs in future rates. Subsequent to this opinion, the legislature adopted ORS 757.259, which authorized the Commission to adopt AACs that incorporate previously incurred costs in future rates.[35] The legislature did not, Staff argues, restrict the Commission to dollar-for-dollar recovery of incurred costs in AACs.

Staff also argues that its proposal is appropriate as a matter of policy, given the scope of PGE's requested increase for these programs and the uncertainty regarding whether PGE can execute its proposed plans. Staff asserts that the majority of PGE's spending is for vegetation management and that its proposal subjects PGE's wildfire mitigation and vegetation management to the efficacy of its vegetation management program.

Staff asserts that its proposed performance-based rate mechanism is an incentive for PGE to implement efficient practices for both wildfire and vegetation management, as well as protection for customers.[36] Staff also states that PGE's AWRR spending is twice PGE's test year expense for wildfire mitigation not categorized as vegetation management. Further, Staff maintains that the $3 million holdback is not punitive and is intended to protect customers from over-recovery of costs, noting that at the time Staff drafted its testimony, it was not clear whether PGE had overestimated its annual spending for wildfire mitigation and vegetation management. Staff acknowledges that PGE is on track to spend more than it requested in base rates for 2022 but asserts that this may not be true for future years. Staff also argues that its proposed mechanism is based on "attainable levels of vegetation management violations set by OPUC Safety Staff" and is only punitive if PGE does not have an effective program.[37]

Staff argues that PGE did not notify parties of either its request to defer incremental wildfire mitigation costs or submit a specific AAC proposal until its surrebuttal testimony and thus no party has had the opportunity to present testimony on either issue. Staff argues that if the Commission adopts an AAC for PGE, that AAC should include sharing

[35] Staff Opening Brief at 14.
[36] Staff Closing Brief at 3 (Mar. 2, 2022).
[37] Staff Closing Brief at 5.

and an earnings test that prevents PGE from recovering incremental expenses for wildfire mitigation even when its earnings exceed its AROE.

3. Resolution

We decline to adopt either Staff's or PGE's proposals. Instead, for the reasons discussed below, we will not adopt any rate adjustment mechanism in this proceeding but invite PGE to file in a separate docket a proposal for a cost recovery method for incremental wildfire costs consistent with SB 762. While we do not direct a holdback, we will closely monitor PGE's progress and spending, and direct PGE to establish a deferral to track any underspending from its planned budgets for these programs.

We first address PGE's proposal. SB 762 provides

> 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.

We are unpersuaded that SB 762 requires adoption of the AAC proposed by the company. We agree with Staff that there are other ratemaking options to carry out the directive that these plan-related costs are "recoverable" and provide for their timely recovery (*e.g.,* forecast-based mechanism). Additionally, we disagree that the language of SB 762 precludes the Commission from crafting a performance-based ratemaking mechanism to evaluate the reasonableness and prudence of a utility's wildfire mitigation activities.

We invite the company to submit a filing proposing a cost recovery mechanism under SB 762 that addresses our need to provide an ongoing review for reasonableness, which may be informed by the company's demonstrated success in vegetation management or other outcomes tied to the company's wildfire mitigation plan. In doing so, we note that PGE did not introduce Schedule 151 until its surrebuttal testimony, which was filed shortly before prehearing briefs and after intervenors submitted their rebuttal testimony. While we recognize that SB 762 was adopted during the course of this proceeding, the development of an AAC requires adequate time and opportunity for the other parties to thoroughly engage on the issues and structure of the mechanism.

We also decline to adopt Staff's proposal, which would subject PGE's cost recovery to an earnings test conditioned on its total vegetation management violations across its service territory. While we implemented a similar proposal in docket UE 374, there, Staff and the company had jointly proposed a combined wildfire mitigation and vegetation management mechanism, with metrics based on vegetation clearance violations.[38] There, we authorized the mechanism for a three-year period, consistent with the company's stated intent to reduce violations over the same period, where there were concerns raised with an increase in violations. In that case, we applied a ten percent holdback to an increased level of test year spending that the company had adjusted midway through the case.[39] Further, we acknowledged that performance metrics based on vegetation clearance violations represented a starting point, with the potential to identify other metrics as docket AR 638 proceeds.[40] Here, Staff's proposal closely tracks the mechanism established in docket UE 374, but the record of this proceeding does not contain support for the amount of the holdback or the metrics proposed. Additionally, as PGE contends, significant work has been done on wildfire mitigation planning since 2019. We intend that any cost recovery mechanism for wildfire be tailored to the company's wildfire mitigation plan.

In this case, PGE's test year budgets included significant increases over 2020 spending. PGE's wildfire mitigation O&M test year budget of $6.6 million represents an increase of $4.6 million over 2020 actuals, and the test year vegetation management budget of $48.7 million is an increase of $22.6 million over 2020 spending.[41] We note that in its surrebuttal testimony, PGE provided an updated 2022 budget of $28.0 million in wildfire mitigation-related O&M (including AWRR activity) and $10 million in wildfire-related capital, attributed to compliance actions and the rapid evolution of wildfire planning since its initial filing.[42] PGE states that it is not seeking to revise its revenue requirement request in this proceeding based on the new budget, and only seeks to recover the test year amounts identified in its initial filing.[43] While Staff reviewed the cost drivers for PGE's proposed test year O&M expense for wildfire mitigation and vegetation management and found no issues, we recognize that these are particularly dynamic and uncertain areas of planning and spending. Here, we balance the need to ensure that the company has the resources it needs to devote to these essential programs, but also recognize the potential for external factors to impede PGE from achieving its projected level of activity in these areas.[44] In particular, we are concerned that skilled labor and equipment shortages could affect PGE's ability to implement this level of spending in future years.[45] Rather than adopting Staff's $3 million holdback, to provide for the possibility that PGE is unable to attain the planned-for level of activity under these

[38] Order No. 20-473, at 115.
[39] *Id.* at 120
[40] *Id.* at 123.
[41] Staff/600, Dlouhy/16.
[42] PGE/2800, Bekkedahl-Tinker-Brownlee/5.
[43] PGE/2800, Bekkedahl-Tinker-Brownlee/4-5.
[44] Staff/600, Dlouhy/18.
[45] Response to Bench Request 7 (Mar.7, 2022).

increased budgets, any unspent amounts relative to PGE's test year budget will be preserved for Commission consideration of potential amortization to ratepayers. We direct PGE to establish a deferral to track any underspending from its planned budgets for these programs. We also direct PGE to submit a filing annually that includes a narrative description of its activities and spending by program. In this filing, PGE shall address with specificity its spending relative to the budgeted amounts for the test year, any planned changes in the budget for the following year, and an explanation for why any anticipated costs did not materialize as expected. We direct Staff to review this filing and present a memorandum summarizing any recommendations. To the extent that PGE is not expending the planned resources on these important programs, any underspend relative to test year budget will be evaluated to determine whether such funds should be returned to ratepayers. PGE should work with Staff to determine the appropriate timing for this annual filing and anticipate revisiting the timing and content of this filing, as well as the length of time this deferral and filing requirement should persist before being reevaluated, in the context of establishing any future recovery mechanism for wildfire mitigation plan costs.

Finally, PGE requests authorization to update its pending request in docket UM 2019 to include its incremental spending for its 2022 Wildfire Mitigation Plan. Any request to update the deferral application or reauthorization requests should be filed in that docket.

B. Level III Outage Accrual Mechanism[46]

1. Accrual Mechanism

a. Background

PGE's current Level III outage accrual mechanism collects funds from ratepayers based on a 10-year rolling average of Level III outage event costs. PGE may carry forward a positive balance in the account but may not carry forward a negative balance in the account. In its last rate case, PGE proposed a balancing mechanism that would allow it to carry negative amounts forward.[47] The Commission rejected PGE's proposal but invited it to propose an alternative in the future. We stated that any future proposal based, in part, on greater storm intensity due to climate change should: (1) include some foundational analysis to support this claim; and, (2) a chain of causation that connects evidence of greater storm intensity and frequency to increased costs. Additionally, we stated that any future proposal should be balanced to ensure that PGE has incentive to develop a robust and resilient distribution system.

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[46] This mechanism has also been referred to as the Level III (Major) Storm Accrual Mechanism.
[47] Order No. 19-129, at 13-14.

b. Positions of the Parties

(1) PGE

PGE argues that its current mechanism is not well-suited for the cluster pattern of events that it has experienced and proposes to modify the Level III outage accrual mechanism to allow it to carry a negative balance forward, subject to a sharing mechanism. Under the sharing mechanism, customers would be responsible for 90 percent of the negative balance to be carried forward and shareholders are responsible for 10 percent. Specifically, PGE proposes a cap of $12 million for either a positive or negative balance. If the balance exceeds $12 million, positive or negative, PGE will amortize the excess amount at the same 90/10 percent share.

PGE argues that it has provided evidence that events are increasing in intensity and that this intensity is linked to higher costs. PGE argues that the majority of the costs it has incurred in the last 27 years[48] were incurred in the last eight years. Further, PGE argues it has provided evidence of trends in frequency, intensity, and costs that conform to predictions for the impacts of climate change on the Pacific Northwest identified in the Fourth National Climate Assessment.[49] PGE also asserts that the deferral of costs associated with declared emergencies does not offset the need for changes to its Level III outage accrual mechanism. Additionally, PGE argues that the historical average fails to account for the increasing unpredictability of event costs due to climate change and increases to costs due to inflation and expansion of its system.

PGE states that while in some years it has carried a positive balance in the reserve, in other years the balance was depleted, leaving PGE to absorb more than $9 million in event costs in 2017. PGE argues that even annual updates to the average would have resulted in inadequate accruals to offset most of these events. Further, PGE argues that AWEC has not explained how the historical average captures a future increase due to inflation and system expansion. PGE agrees with Staff that the historical costs account for past inflation but argues that the average does not capture future inflation after the accrual amount is set. PGE also argues that the beneficial impacts of system hardening do not offset system expansion, because system hardening may lower the risk but cannot eliminate the risk completely.

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[48] In testimony, PGE originally presented a 26-year analysis. PGE/1400, Tooman-Batzler/41. Following AWEC's arguments around the 26-year period, PGE included an analysis for a 27-year period, which is the analysis it refers to in its brief. PGE/2400, Bekkedahl-Tooman/5-6; PGE Opening Brief at 24 (Feb 22, 2022).

[49] PGE Opening Brief at 24; PGE/800, Bekkedahl-Jenkins/66-67, *citing* Fourth National Climate Assessment, Chapter 24, at https://nca2018.globalchange.gov/chapter/24/.

(2) Staff

Staff argues that PGE's proposed changes to the Level III mechanism are not necessary because the costs of Level III storm events have not been trending upward over time according to statistical analysis. Staff asserts that while there may be an increase in the frequency of events, the costs per event are decreasing and approximately offset any such increase. Staff also states that PGE's cited eight-year period is an arbitrary cut off and the correct way to determine if future years will have higher costs is by statistical analysis.

Staff also argues that the costs of declared emergencies should not be included in any analysis of cost trends for Level III storms. Staff asserts that the current Level III mechanism is sufficient for the outages to which it will be applied, given that PGE frequently seeks recovery for extraordinary storm costs outside of the Level III mechanism and has testified that it will continue to do so. Staff further argues that now that PGE has a deferral account for outage events that are declared emergencies there is no need to permit the Level III accrual to carry a negative balance.

Staff also argues that inflation is included in the current ten-year rolling average because it is based on constant dollars. Additionally, Staff also states that while mild years may pull the average downward, years with severe storm activity pull the average upward. Staff also argues that the approximately $8 million balance in the reserve in 2020 does not support PGE's assertion that the current mechanism is insufficient.

Finally, Staff disputes that the proposed mechanism is appropriate to incentivize PGE to harden its system and argues that PGE is most incentivized when its Level III expenses are set on a forward-looking basis. Staff states that PGE's GRC provides for significant revenue for system hardening on a forward-looking basis. Additionally, Staff points to PGE's statement that it has invested over $800 million in poles and wires, which PGE has said were designed, among other things, to withstand increasing weather events due to climate change.

As an alternative to PGE's proposal, Staff proposes to update the rolling ten-year storm cost average on an annual basis. Staff argues this balances the risk between customers and PGE.

(3) CUB

CUB opposes PGE's proposal and instead recommends modifying the Level III outage accrual mechanism to allow PGE to carry a negative balance, subject to a hard cap of two times the annual accrual amount. CUB argues that its proposal adequately accounts for the storms that affect PGE's system and fairly balances risk between customers and PGE. In the alternative, CUB supports Staff's proposal but recommends that the annual rate change occur on January 1 of each year. CUB does not support combining its proposal with Staff's proposal. CUB contends that the hard cap under its proposal provides greater protections for customers than the small amount of sharing PGE proposed.

CUB argues that PGE's proposal does not satisfy the criteria set out by the Commission. Specifically, CUB asserts that PGE has failed to provide evidence sufficient to justify the proposal and that storm costs are not increasing even if frequency might be. CUB also asserts that PGE's proposal shifts risk to customers in an unbalanced manner. Further, CUB argues that PGE's asymmetric sharing proposal provides little incentive to control costs. CUB asserts that the level to which PGE proposes to alter the mechanism is not supported by the evidentiary record.

(4) AWEC

AWEC argues that the current 10-year average is adequate and asserts that PGE's analysis of 26 years of storms is flawed. AWEC states that it provided an analysis that demonstrates that PGE's costs declined over a 27-year period and asserts that even under PGE's analysis only slightly more than half of the costs occurred in the second half of PGE's analysis. AWEC also argues that a slight increase in costs is expected over time due to inflation and PGE's expansion of its service area in the period in question. AWEC asserts that PGE has not disputed AWEC's evidence that the current methodology adequately captures climate change impacts.

c. Resolution

We reject PGE's proposal, but we will adopt changes to the Level III outage accrual mechanism. We adopt CUB's proposed revisions to the mechanism.

In Order No. 18-464, we invited PGE to propose changes to the Level III outage accrual mechanism that provided a foundational analysis for claims of greater storm intensity due to climate change and a chain of causation that connected evidence of increased storm frequency and intensity with increased costs.[50] As detailed above, PGE, Staff, CUB, and AWEC have each provided analyses regarding the frequency and cost of Level III outage events. After reviewing the various analyses and costs presented throughout this proceeding, this record made clear there are several drivers of cost. Some are rooted in adapting to climate change, such as increased construction standards and perhaps more extreme storms, while others, such as inflation in materials and labor costs, cannot be entirely tied to climate change impacts.[51]

[50] Order No. 18-464 at 14.
[51] PGE/800, Bekkedahl-Jenkins/65-67, 74; PGE/1400, Tooman-Batzler/40-43; PGE/2000, Bekkedahl-Jenkins/28-29; PGE/1405, Tooman-Batzler; PGE/2400, Bekkedahl-Tooman/8-11; Staff/1400,

PGE argues that climate change is spurring a variety of Level III outage events that tend to arrive in clusters. While PGE provides some evidence that climate change is increasing the variety and severity of events in the Pacific Northwest, PGE is also seeking to invest a significant amount into increased vegetation management and system hardening that should enhance system resiliency against storms and other events, reducing outages and storm recovery costs to some degree.[52]

Staff and CUB argue that the cost of event response has not risen while the frequency may have and that clustering should ensure that PGE is building a balance that it can draw from in years with more events. PGE has demonstrated that, in some years, storms have been significant enough to zero the account and cause PGE to absorb the remaining costs.[53] While, to date, the account has not been permitted to carry a negative balance, PGE provided evidence of what that negative balance would have been.[54]

PGE originally proposed the Level III outage accrual mechanism to replace the insurance that it could no longer purchase at a reasonable price.[55] It was not intended to provide dollar-for-dollar recovery for Level III outage events. PGE's proposal offers a modest sharing component for any negative balances or amounts over the positive or negative $12 million soft cap, but it shifts the allocation of risk significantly from PGE to customers. Only PGE can take the preventative actions necessary to reduce storm impacts, including careful prioritization and efficient deployment of increased spending on vegetation management and system hardening, so it is appropriate that some risk of the cost of storm impacts remain with the company.

Though PGE's proposal shifts too much risk to customers, we find that some changes to the Level III mechanism are warranted. Under CUB's proposal, PGE could carry a limited negative balance for the Level III account capped at two times the accrual amount. We find that CUB's proposal recognizes that PGE is experiencing a greater variety of outage events in clusters that warrant some revisions to the mechanism without shifting the majority of the risk from PGE to customers. We appreciate Staff's proposal as another option for a limited and incremental revision to the mechanism, but the proposal does not as completely address the desire to expand the operation of the mechanism while limiting risks to customers. Additionally, Staff's proposal would add the need for new annual filings to update storm event costs, which we are concerned would involve additional administrative burden, with the potential for disputes. CUB's

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St. Brown/6-7; Staff/2700, St. Brown/3-6; AWEC/100, Mullins/39; AWEC/300, Mullins/21-22; AWEC/300, Mullins/21-22.

[52] *See, e.g.,* PGE/800, Bekkedahl-Jenkins/45, 54-57, 72; PGE/100, Pope-Sims/11.

[53] PGE/816, Bekkedahl-Jenkins/2.

[54] *Id.*

[55] *In the Matter of Portland General Electric, Request for General Rate Revision*, Docket No. UE 215, PGE/800, Hawke-Nicholson/11-14 (Feb. 16, 2010); Docket No. UE 215, PGE/1000, Pope-Tooman/7-9 (Feb. 16, 2010).

proposal, by contrast, allows PGE to recover some additional costs without the need for the Commission and parties to review and approve a filing every year. Therefore, we adopt CUB's proposed change to allow PGE to carry a negative balance, subject to a hard cap of twice the annual accrual.

2. *Level III Outage Events*

a. Introduction

PGE argues that wildfires may be included in the Level III outage accrual mechanism because there is nothing in the definition of a Level III outage event that limits such events to traditional storms. PGE argues the mechanism was designed to address Level III outage events, which are defined by the impacts, not the cause. In testimony, Staff agreed that the definition of a Level III outage could include a wildfire.[56]

CUB maintains that this mechanism was not designed to include wildfires when it was established. CUB asserts that PGE is parsing language from docket UE 215 to inappropriately expand the mechanism and that PGE is able to recover wildfire costs through its emergency deferral process.

b. Resolution

We find that the Level III outage events can include wildfire impacts that meet the definition of a Level III outage. The original Level III outage accrual mechanism was adopted by stipulation in docket UE 215, and there is very little information provided about the expectations of the parties when the mechanism was agreed to. Although the stipulation only refers to Level III storms, the definition of Level III outage events was then as it is now neutral to the cause of the outage. In testimony, PGE requested a balancing account that would "track the difference between what [it] characterize[s] as a 'Level III outage' actual costs and the amounts collected in rates."[57] Though the testimony also refers primarily to storms, the actual outage criteria are not limited to storms. Further, there is also likely to be some overlap or connection between storm-caused outages and wildfire-caused outages as there were during the Labor Day wildfires in 2020, which could be difficult to separate for the purposes of determining outage response costs.[58]

We note, however, that the purpose of the Level III outage accrual mechanism is to account for outage events for which PGE can no longer obtain insurance coverage at a reasonable cost. To the extent that PGE has insurance coverage for wildfire damage, it may not recover through the Level III mechanism any costs for events expected to be

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[56] Staff/2700, St. Brown/7.
[57] Docket No. UE 215, PGE/800, Hawke-Nicholson/11-12 (Feb. 16, 2010).
[58] *See*, *e.g.*, PGE/800, Bekkedahl-Jenkins/64, 68; PGE Prehearing Brief at 37-38.

covered by insurance. Nor may PGE recover for any Level III outage event costs related to wildfires that it is already recovering through rates or other mechanisms. If PGE later receives insurance payouts for events previously recovered through the Level III mechanism or other rate, PGE must file to defer those payouts and submit a filing to address the appropriate treatment of the insurance payout.

C. Process Regarding Faraday Repowering Project

1. Introduction

In its initial filing, PGE proposed to include the repowering project at PGE's Faraday Hydro Plant on the Clackamas River in rate base. The Faraday project involves replacement of five of six original units at the plant and the original powerhouse where it is adding two higher efficiency turbines and new flood protection systems. At the time PGE filed its initial testimony in this case, it estimated that the Faraday project would be complete in March 2022.[59]

During this proceeding, Staff raised concerns about the prudence of the Faraday project—regarding both the initial analyses done by PGE prior to undertaking the project and how the project was managed.[60] Other parties raised similar concerns as well as questions about whether the project would be completed by the estimated March 2022 date or by the rate effective date.[61]

Subsequently, PGE confirmed that the Faraday project would not be online in spring 2022. In its surrebuttal testimony, PGE estimated the project would instead be online in December 2022. In the third partial stipulation, addressed above, the stipulating parties agreed to remove the Faraday project from the rates going into effect on May 9, 2022. PGE now requests that the Commission provide for a "Phase II" of this rate case to be opened three months prior to the new in-service date so that prudence issues related to the Faraday project can be considered and the project can go into rates upon its completion.

2. Positions of the Parties

a. PGE

PGE states that the Faraday project is currently 70 percent complete, meaning that the parties could already begin a significant prudence review of the costs incurred to date, and notes that parties have filed testimony on some prudence issues. PGE also notes that Staff questioned PGE's decision to repower Faraday as an initial matter which, it argues,

[59] PGE/700 Jenkins-Cristea/5.
[60] Staff/1000, Enright/11-26.
[61] AWEC/100, Mullins 20.

"turns on historical information already available to the parties."[62] PGE asserts that it is common to review the prudence of a capital addition during the final phases of construction and that several assets at issue in this proceeding were evaluated during their final phases. Further, PGE asserts that there is no need to wait for final costs to begin the prudence review and that it will provide an estimate of the Faraday project's final costs for the parties to evaluate during Phase II.

PGE acknowledges that seeking Phase II of a rate case is not common but asserts that the Commission has approved allowing major assets into rates without a full ratemaking hearing when a major asset was coming into service relatively soon after a rate case. PGE cites to Port Westward 2, Tucannon, and Carty[63] as examples. Further, PGE argues that while most of the examples were approved in stipulations, the Mona-to-Oquirrh tariff rider was approved over parties' objections.[64] PGE contends that it would be inefficient to require a new GRC to put the Faraday project into rates less than one year after this GRC concludes. Additionally, PGE asserts that a Phase II proceeding allows for more opportunity to review than a typical rate case, because the parties have already reviewed initial project costs and the repowering decision. PGE also states that regardless of whether the other cited projects were approved through stipulation, the Commission still found it reasonable to allow these costs into rates many months after the rate-effective date. PGE further notes that PGE's 2022 annual update tariff included the value of Faraday repowering-related production tax credits and an energy benefit of approximately $5 million. Similarly, PGE notes that its net plant amount and inflation are expected to increase between the rate-effective date and the Faraday project's expected in-service date. Thus, PGE states, allowing a Phase II case would align the costs and benefits to customers.

PGE asserts that while the Faraday project was not included in PGE's IRP, the Faraday project's generation is consistently included in PGE's resource planning.

b. Staff and Intervenors

Staff, AWEC, and CUB all take the position that the Faraday project should be considered in the next GRC rather than in a Phase II of this proceeding. Staff argues that PGE's proposal constitutes single issue ratemaking and notes that the Commission has stated that an applicant must demonstrate extraordinary circumstances to warrant an exception to typical ratemaking. Staff's position is that PGE has made no such showing here.

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[62] PGE Opening Brief at 5.
[63] PGE Prehearing Brief at 11-12; Staff/2500, Enright/9, Table 1, Summary of Recent Tariff Riders.
[64] PGE Closing Brief at 6 (Mar. 2, 2022), *citing In the matter of PacifiCorp's Request for a General Rate Revision*, Docket No. UE 246, Order No. 12-493 at 4-8 (Dec. 20, 2012).

Regarding similar post-proceeding tariff riders, Staff, CUB, and AWEC all argue that the prior tariff riders approved by the Commission do not support PGE's position regarding the Faraday project. In particular, Staff contends that when such tariff riders have been approved by the Commission, the parties had already stipulated to the prudence of the project. Staff, CUB, and AWEC also point out that unlike the other projects for which a tariff rider was used, the Faraday project was not vetted in an IRP. CUB also notes that the longest period of time between a GRC and a tariff rider that the Commission has ever approved is the Port Westward project, which came into service midway through the test year.[65] CUB asserts that had the Port Westward project come online later than September 2007, PGE would have had to file a new rate case to bring it into rates.[66]

Additionally, Staff, CUB, and AWEC also note that the Faraday project's online date is still not reasonably certain. Staff argues that while it is not necessarily unusual to review prudence before an asset is in service, such a review should not occur in this case given the issues raised regarding the project. Similarly, CUB argues that it would be inappropriate to complete a prudence review before the project is complete and total costs are reasonably known, particularly considering that the project is already more than 100 percent over budget and could suffer additional delays. AWEC also argues that the consideration of the Faraday project should be postponed until final costs can be evaluated and thus the prudence of the whole project determined. AWEC further argues that the issues with PGE's proposal are compounded by the fact that PGE has not provided an updated budget for the project.

Staff argues that a Commission decision allowing the Faraday project to go into rates in mid-2023 would mean that PGE receives an increase in rates without a corresponding examination of whether other expenses presented in this rate case are lower than projected. Similarly, CUB argues that PGE's proposal does not provide the ability to ensure that the test year forecast in this proceeding is still accurate. CUB further argues that PGE's presentation of the costs and benefits of the Faraday project has been inadequate and misleading.

Regarding the potential cost and benefit mismatch cited by PGE, AWEC argues that PGE included Faraday repowering tax credits and energy benefits in its annual update tariff knowing that it would be resolved before its rate case, and PGE therefore accepted the risk of a potential mismatch between the cost and benefits for the Faraday project.

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[65] CUB/400, Jenks-Gehrke/25, *citing In the Matter of Portland General Electric Company's Request for a General Rate Revision*, Docket No. UE 184, PGE/100, Lesh/2.
[66] CUB/400, Jenks-Gehrke/25, *citing In the Matters of Portland General Electric Company's Request for a General Rate Revision* (Docket No. UE 180), *Annual Adjustments to Schedule 125* (Docket No. UE 181), *Request for a General Rate Revision relating to the Port Westward Plant* (Docket No. UE 184), Order No. 07-015 (Jan. 12, 2007).

3. Resolution

We reject PGE's proposal for a Phase II proceeding regarding its Faraday project. Under traditional ratemaking, we set rates for a future period, or the test year, based on a forecast of the utility's expected costs and revenue needs.[67] In a rate case setting, we are able to evaluate not only the revenue requirement needs associated with any added capital, but also all other utility expenses, to ensure that rates are, overall, just and reasonable.

Under our standard ratemaking process, PGE will have the opportunity to recover a return of and return on the plant balances included in rate base until its next rate case, even as the value of those assets depreciates and plant is retired. The benefit of continuing to collect rates on the rate base established in the prior rate case is countered by the ongoing capital investments a utility makes that will not be placed into rates during that period. Thus, there is a balance between regulatory lag experienced by the company before plant is included in rate base, and lag experienced by ratepayers associated with the removal of depreciated plant from rates. In this instance, providing for a Phase II for the Faraday project would involve a prudence examination well beyond the rate effective date for this GRC, and eliminate any lag for PGE on this project without any corresponding update to rate base to reflect potential benefits to customers from depreciation of other utility plant in rate base.

While we understand that unexpected events may cause delays for projects and inconvenient timing in terms of rate case filings, that alone is not enough to warrant an exception to general ratemaking principles. Here, PGE has not demonstrated that there will be a significant gain in efficiency by opening a second phase to examine the Faraday project, particularly so long after this GRC will be decided. There is no guarantee that if we consider the Faraday project as part of a Phase II of this proceeding, PGE will not file another GRC in the near term. Additionally, PGE's proposal to address the Faraday project in a Phase II is also distinguishable from prior circumstances in which we allowed plant to be included in rates subsequent to a rate case. Not only is there a significant length of time between the conclusion of this GRC and the expected in-service date for the Faraday project, but there is insufficient evidence in this record to conclude with a high degree of confidence that Faraday will in fact be in service within the test year. Finally, the project has not already been considered as part of the IRP process, and the parties have indicated that there are likely to be significant disputes regarding prudence. Taken as a whole, PGE has not provided sufficient evidence that an exception to general ratemaking principles is warranted.

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[67] *In the Matter of the Scope of the Commission's Authority to Defer Capital Costs*, Docket No. UM 1909, Order No. 20-147 at 3 (Apr. 30, 2020).

After the Faraday project is complete and in service, PGE may seek to recover those costs in its next GRC. We note, however, that PGE is not foreclosed from requesting recovery of Faraday costs in a single-issue rate case in the future. As we have stated in prior orders, there are certain risks and shortcomings for ratepayers associated with single-issue ratemaking.[68] In consideration of these risks, we have previously held that parties seeking a single-issue rate proceeding must demonstrate that the circumstances warrant an exception to traditional ratemaking through a GRC.[69] To the extent that PGE requests such a single-issue rate case, it should be prepared to make such a demonstration. Additionally, as AWEC points out, any other parties would be free to argue for the updating of other costs or revenues in that proceeding.

D. Deferrals

1. Introduction/Background

On September 10, 2020, PGE filed a request to defer costs associated with the Labor Day 2020 wildfire (wildfire deferral) in docket UM 2115. The Commission authorized the wildfire deferral for the one-year period starting September 10, 2020.[70] That authorization included establishing a regulatory asset for undepreciated plant no longer used and useful due to wildfire damage. At the March 8, 2022 Public Meeting, we adopted Staff's recommendation to reauthorize the deferral and the regulatory asset for the undepreciated plant no longer in service for another year.[71] Total costs are identified to be approximately $59.1 million as of May 9, 2022.[72]

On October 8, 2020, AWEC and CUB filed a request to defer revenue impacts associated with the October 15, 2020 retirement of the Boardman coal-fired generating facility (Boardman deferral) in docket UM 2119. AWEC and CUB filed a request for reauthorization of the deferral request for the period October 8, 2021 through the

[68] *In the Matter of Cascade Natural Gas Corporation's Application for Safety Cost Recovery Mechanism*, Docket No. UM 2026, Order No. 20-015 at 11-12 (Jan. 15, 2020). *See also In the Matter of Northwest Natural's Request for a General Rate Revision*, Docket No. UG 221, Order No. 12-437 at 58 (Nov. 16, 2012) ("If rates are increased based solely on the fact that one type of expense is higher than expected, without considering changes to other elements of revenue requirement, the company's reasonable revenue requirement could be overstated.").
[69] Order No. 20-015 at 11-12; Order No. 12-437 at 58 (finding that a requested amortization was single-issue ratemaking and stating that "[e]xcept in limited circumstances, it is improper to consider changes to components of the revenue requirement in isolation").
[70] *In the Matter of Portland General Electric Company, Application for Deferral of Wildfire Emergency Costs and Lost Revenues*, Docket No. UM 2115, Order No. 20-389 (Oct. 27, 2020).
[71] *In the Matter of Portland General Electric Company, Application for Deferral of Wildfire Emergency Costs and Lost Revenues*, Docket No. UM 2115, Order No. 22-077 (Mar. 11, 2022).
[72] AWEC/300, Mullins/3.

effective date of rates in this GRC. The total costs as of May 9, 2022 are estimated at approximately $109.9 million.[73]

On February 15, 2021, PGE filed a request to defer emergency restoration costs for the February 2021 ice storm (ice storm deferral) in docket UM 2156. At the January 25, 2022 public meeting, the Commission authorized the ice storm deferral for February 15, 2021 through February 14, 2022.[74] At the March 8, 2022, Public Meeting, the Commission amended its prior order to also authorize a regulatory asset for the undepreciated investment in plant no longer used and useful as a result of the ice storm.[75] As of May 9, 2022, the deferral balance is projected to include costs of approximately $65.8 million.[76]

PGE recommends addressing each of the three deferrals in their individual, existing dockets, rather than within this GRC. PGE argues that if the Commission considers the deferrals in this case, the Commission should deny authorization of the Boardman deferral. AWEC, CUB, and Staff contend the Commission should authorize the Boardman deferral in this case. Staff, CUB, and AWEC offer different proposals regarding how and where amortization review of the three deferrals should be handled. Below, we address the threshold question of authorization of the Boardman deferral, as well as the issues raised regarding amortization review.

2. Boardman Deferral Authorization

a. Background

Boardman was a 575 MW coal-fired generating facility, 90 percent owned by PGE. On November 23, 2010, in PGE's 2009 IRP, the Commission acknowledged the closure of Boardman no later than 2020.[77] Boardman was ultimately closed on October 15, 2020. PGE's current rates, established in its last GRC, docket UE 335, included costs associated with PGE's investment in the Boardman facility and its operations. The costs of Boardman are not included in the rates proposed for effect May 9, 2022, in this docket.

In their deferral application, AWEC and CUB requested the Commission authorize deferral of the expenses and capital costs associated with Boardman included in the company's base rates beginning on the plant's closure date. On October 8, 2021, AWEC

[73] AWEC/301, Mullins/2.
[74] *In the Matter of Portland General Electric Company, Application for Authorization to Defer Emergency Restoration Costs*, Docket No. UM 2156, Order No. 22-020 (Jan. 26, 2022).
[75] *In the Matter of Portland General Electric Company, Application for Authorization to Defer Emergency Restoration Costs*, Docket No. UM 2156, Order No. 22-075 (Mar. 11, 2022).
[76] AWEC/300, Mullins/3.
[77] *In the Matter of Portland General Electric Company, 2009 Integrated Resource Plan*, Docket No. LC 48, Order No. 10-457, 15-17 (Nov. 23, 2010).

and CUB sought reauthorization of the deferral through the rate effective date of this GRC.

In PGE's 2010 GRC, the Commission adopted a stipulation that established Schedule 145, to allow rates to reflect a shortened operating life for Boardman. Schedule 145 provided a mechanism to allow the Commission to authorize rate changes to reflect the incremental revenue requirement effect of a shortened operating life.[78] The Commission approved PGE's request to increase rates under Schedule 145 to include the accelerated depreciation and decommissioning costs associated with the planned closure date changing from 2040 to 2020, effective July 1, 2011.[79] Effective January 1, 2014, the accelerated depreciation costs were included in base rates, with decommissioning costs remaining in Schedule 145.[80] Schedule 145 was also used to recover expenses associated with a reliability plan for Boardman employees, including severance and retention costs outside of base rates beginning in 2016.[81] Decommissioning costs associated with Boardman were recovered via Schedule 145 through December 31, 2021.[82]

AWEC, CUB, and Staff argue that the Commission should authorize the Boardman deferral in this docket. They contend that authorization of the Boardman deferral is warranted because it meets the statutory and discretionary criteria for deferral, and deferral is necessary to ensure that PGE does not earn a return on plant that is no longer used to provide utility service. PGE argues that the Commission should deny authorization of the Boardman deferral, contending that Staff, AWEC, and CUB have not demonstrated that closure of the plant is the type of event to warrant a deviation from traditional ratemaking treatment, or that customers have been harmed by Boardman remaining in rates. PGE also disputes that ORS 757.355 requires the immediate removal of a retired plant from rates.

b. Positions of the Parties

(1) PGE

PGE argues that Commission's standard for reviewing deferral requests "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

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[78] Order No. 10-478.
[79] *In the Matter of Portland General Electric* Company, Advice No. 11-07 Schedule 145 Boardman Adjustment Update, Docket No. UE 230, Order No. 11-242 (Jul. 5, 2011).
[80] See sixth revision of Schedule 145 (E-18, Adv. No. 13-30), filed December 13, 2013, effective January 1, 2014).
[81] Schedule 145 Boardman Power Plant Decommissioning Adjustment, Docket No. ADV 121/Advice No. 15-24 (Dec. 15, 2015 regular public meeting).
[82] Schedule 145 Boardman Power Plant Decommissioning Adjustment, Docket No. ADV 1328, Advice No. 21-28 (Nov. 30, 2021 regular public meeting).

of both factors."[83] PGE acknowledges that the decision to close Boardman in 2020 rather than 2040 was a major milestone in PGE's clean energy transition. However, PGE asserts that the closure itself, coming ten years later in 2020 was not unexpected. PGE maintains that to adopt 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.

PGE disputes CUB's contention that ORS 757.355 requires the immediate removal of a retired plant from rates. PGE argues that the Commission has stated 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 retired plant.[84] PGE maintains that its rates remained fair, just, and reasonable after Boardman's closure because the amount of associated depreciation and return is more than offset by new rate base investments not yet included in rates. Additionally, PGE argues that utilities do not remove assets from rates immediately upon their retirement, and could not because to do so would require almost daily rate changes. PGE asserts that this approach is also asymmetrical, ignoring utilities' ongoing investments in their systems while receiving no cost recovery until the investments are authorized by the Commission.

PGE asserts that leaving a retired asset in rates until the next rate case, while making new investments that are not yet included in rates is consistent with traditional ratemaking principles. PGE asserts that 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.[85]

PGE contends that in this instance, the benefit of leaving Boardman in rates until this rate case was more than offset by continued capital investments that will not enter rates until the rate-effective date of this case. PGE argues that the reduced costs from the closure of Boardman, load growth, and management of O&M costs allowed PGE to absorb

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[83] PGE Opening Brief at 29, *citing In the Matter of Utility Reform Project, Application for Deferred Accounting*, Docket UM 1124, Order No. 09-316 at 14 (Aug. 18, 2009)
[84] PGE Opening Brief at 30, *citing In the Matters of The Application of Portland General Electric Company for an Investigation into Least Cost Plan Plant Retirement, Revised Tariffs Schedules for Electric Service in Oregon Filed by Portland General Electric Company, Portland General Electric Company's Application for an Accounting Order and for Order Approving Tariff Sheets Implementing Rate Reduction*, Docket Nos. DR 10, UE 88, UM 989, Order No. 08-487 at 21 (Sep. 30, 2008); *Gearhart v. Public Utilities Commission of Oregon*, 255 Or App 58, 94 (2013); *Gearhart v. Public Utilities Commission of Oregon*, 356 Or 216, 237 n. 15 (2014).
[85] PGE Prehearing Brief at 44, *quoting* Order No. 20-147 at 13.

significant regulatory lag associated with new plant investments and delay filing this rate case. PGE maintains that in the ten years since the decision to close Boardman, the company has had five rate cases, during which no party proposed to implement a mechanism is remove Boardman from base rates. PGE also argues that it 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, under traditional ratemaking practices.

PGE argues that retaining Boardman costs in rates did not result in substantial harm to customers to warrant deferred accounting. PGE asserts that the amount of regulatory lag PGE has experienced far exceeds PGE's reduced costs due to Boardman's closure. 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), after factoring in the savings from Boardman and revenue growth. PGE opposes CUB's argument 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. PGE argues that the Commission considers the fairness of PGE's rates as a whole, not on an asset-by-asset basis.

PGE disagrees that it is unfair for PGE to benefit from regulatory lag after the Boardman closure because new renewable resources are subject to the RAC, thus avoiding regulatory lag when they are placed in service. PGE contends that disregarding RAC-eligible Wheatridge, the remaining lag more than offsets the Boardman costs that remained in rates. PGE also argues that the RAC was established by law to promote the transition to renewable energy, and PGE's use of this means to recover for renewable resources is not analogous to the Boardman deferral, which PGE contends would be a major deviation from the traditional ratemaking process and is not authorized by statute like the RAC.

PGE also disputes that the state policy to remove coal plants from rates constitutes an extenuating circumstance supporting the Boardman deferral. PGE contends that Oregon law requires PGE to eliminate coal-fired generation by 2035, and by retiring Boardman in 2020 and removing it from rates on May 9, 2022, PGE is ahead of schedule. PGE also disputes that the treatment for Boardman should mirror that of PacifiCorp's and Idaho Power's retired coal plants, explaining that those companies own multiple coal plants over multiple states, whereas PGE has closed the only coal plant it operates. PGE argues that in the case of Boardman, therefore, there is no need to implement a tracker or other special regulatory mechanism.

(2) AWEC, CUB, and Staff

AWEC, CUB, and Staff agree that the Commission should approve the Boardman deferral authorization and reauthorization in this docket. AWEC contends that ORS 757.355(1) prohibits PGE from earning a rate of return on plant that is no longer used and useful. AWEC maintains that the Court of Appeals has explained that this provision is intended to ensure that "property that is not 'reasonably necessary to and actually providing utility service' is ineligible for either inclusion in the rate base or for a rate of return payable by utility customers," and that this applies to "property that has ceased being used for the provision of services as well as property that has never been so used."[86] CUB maintains that in applying ORS 757.355, the Commission has held that "[t]he critical issue is whether the … assets were being 'used for providing utility service to the customer,'" and where no utility service was rendered, the utility should not receive any compensation.[87] CUB, AWEC, and Staff assert that since its closure date, Boardman has not been used and useful, and thus customers must not pay for its costs.

CUB asserts that in the Dreyer case, the Oregon Supreme Court held that amounts PGE collected after the Trojan facility's closure were "in violation of ORS 757.355, and the issue was whether ratepayers had been injured by this violation.[88] CUB contends that the Oregon Supreme Court's opinion in Dreyer was clear that collecting amounts in contravention of ORS 757.355 was unlawful. CUB asserts that the Court in Dreyer also recognized "that the PUC has primary jurisdiction to determine what, if any, remedy it can offer PGE ratepayers, through rate reductions or refunds, for the amounts PGE collected in violation of ORS 757.355."[89] CUB argues that the Commission should find that PGE's ratepayers have been harmed by PGE's unlawful recovery of post-closure Boardman costs and direct a remedy of the return of the deferral balance to ratepayers over three years. CUB argues that because the revenues customers paid for Boardman have been placed in a deferred account, the Commission is able to refund the amount that has been collected in violation of ORS 757.355. CUB disputes PGE's contention that its interpretation of ORS 757.355 would require utilities to change their rates "every time they replace a transformer or pole" and argues that this instance concerns the retirement of Oregon's only coal plant, a significant event that is associated with a significant amount of money.[90] CUB distinguishes this "once-in-a-lifetime transition" from the replacement of plant such as transformers, poles, and any lesser plant subject to group depreciation.[91] CUB argues against applying an earnings test to the Boardman deferral,

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[86] AWEC Opening Brief at 4 (Feb 22, 2022), *quoting Citizens' Utility Board v. Public Utility Commission of Oregon*, 154 Or App 702, 708-710 (1998).
[87] CUB Opening Brief at 7 (Feb 22, 2022), *citing* Order No. 08-487 at 77.
[88] CUB Opening Brief at 7, *quoting Dreyer v Portland General Electric Company*, 341 Or 262, 286 (2006).
[89] CUB Opening Brief at 8, *quoting Dreyer*, 341 Or at 286.
[90] CUB Opening Brief at 8.
[91] CUB Opening Brief at 8.

arguing that failing to return the entire balance to customers would be unlawful under ORS 757.355.

AWEC, CUB, and Staff contend that the Boardman deferral satisfies the requirements of ORS 757.259(2), because it will appropriately match costs and benefits for customers. They argue that because ratepayers have not benefitted from Boardman following its closure date, it is not appropriate for ratepayers to pay for costs beyond that date. They further assert that the deferral satisfies the Commission's discretionary criteria because the balance of $109,904,915 as of May 9, 2022, representing 5.29 percent of PGE's revenue requirement, is substantial in magnitude.[92] They argue that the Boardman deferral is justified in order to ensure that PGE does not earn a return on plant that is no longer providing utility service.[93]

AWEC, CUB, and Staff argue that because Boardman's closure was foreseen, it is a stochastic risk, and thus the magnitude of the deferral must be substantial or there must be extenuating circumstances to justify amortization. They also agree that the estimate of $109,909,915 is substantial in magnitude, satisfying the criterion for deferral of a stochastic risk. CUB and Staff contend that PGE's collection of revenue for over a year for a plant that is no longer in service is an extenuating circumstance that justifies deferral.

CUB disputes PGE's contention that retaining Boardman's costs in rates did not result in substantial harm to customers due to the lag absorbed during the same period. Staff argues PGE is conflating the analysis for authorizing a deferral with that of authorizing amortization. Specifically, Staff argues that the Commission does not consider the magnitude of the impact by considering a utility's other costs and revenues during the deferral period, and reserves that analysis for evaluating amortization. Otherwise, Staff argues that the Commission should consider offsetting revenues or cost savings in evaluating utility requests for deferral of an unexpected event. CUB argues that the test relevant to the deferral criteria is whether the magnitude of costs related the event is substantial or that there were extenuating circumstances, not whether PGE experienced what it perceives to be offsetting costs.

CUB argues that refunding the Boardman costs collected in rates would further Oregon's policy to decarbonize the electric system. CUB contends that ORS 757.518 requires Oregon electric utilities to remove coal plant related costs from rates by January 1, 2030, and that Oregon ratepayers have been required to bear significant costs to accelerate the closure of coal plants throughout the west to comply with this requirement. CUB points out that in this GRC, PGE seeks to recover additional costs associated with the accelerated closure of Colstrip Units 3 and 4. CUB maintains that because these costs are

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[92] AWEC Opening Brief at 4-5, *citing* AWEC/301, Mullins/2, PGE Prehearing Brief, Attachment 1 at 1.
[93] AWEC Opening Brief at 3-4, *citing* ORS 757/259(2)(e); ORS 757.355(1).

being passed to customers in an accelerated manner to enable early closures, passing any benefits to customers is necessary.

CUB argues that the Boardman deferral mirrors the treatment for retired coal plants on PacifiCorp's and Idaho Power's systems. CUB asserts that there is no reason why PGE could not have made a similar proposal as Idaho Power, and that allowing PGE to sidestep this established regulatory policy would create a perverse incentive for PGE to charge customers for retired plant as long as it can. CUB argues that PGE has been able to utilize trackers and accelerated depreciation to protect its shareholders from the impacts of the transition away from coal, and that it is equitable to ensure that ratepayers get the benefit of retiring coal resources. CUB notes that PGE was allowed to accelerate Boardman's depreciation outside of base rates via separate trackers between 2011 and 2013, resulting in increased short-term costs for customers and that the costs of replacement renewable resources are placed into customers' rates through the RAC, avoiding lag and without an earnings test. CUB asserts that it would be unfair for customers' rates to reflect the accelerated depreciation of a coal plant that is not providing power as well as the costs of the renewable energy investments that replaced the coal plant. CUB argues that if customers are treated unfairly in this transition, some intervenors may oppose the transition from coal. CUB contends that PGE's shareholders recovered their full Boardman investment, which was fully depreciated in 2020, but that under PGE's proposal, customers would be paying for more than the actual costs associated with retiring the plant.

CUB also points to PGE's use of Schedule 145 to recover costs associated with the retention and severance of PGE's employees at Boardman outside of a GRC process, with customers having funded $14 million in such costs as of June 2020.[94] CUB argues that by seeking to retain the amounts in the Boardman deferral, PGE is asking customers to fund retention and severance benefits for PGE's Boardman employees while the company enjoys reduced labor costs.

c. Resolution

ORS 757.259(2)(e) sets out a two-prong test, under which the proposed deferred account must either minimize the frequency or fluctuations of rate changes or match the costs and benefits received by ratepayers. Here, we find that authorization will ensure the costs and benefits received by ratepayers are matched, by allowing us to evaluate whether continued recovery of Boardman costs in rates resulted in ratepayers overpaying in overall rates.

[94] CUB Opening Brief at 14, *citing* CUB/400 at 15.

Under our discretionary analysis, we examine the nature of the event, its impact, the treatment in ratemaking, and other factors to evaluate whether a deferred account is appropriate. We examine the magnitude of the underlying event in terms of the potential harm. We find that the Boardman costs, which were included in rates, were of a sufficient magnitude that, in conjunction with the other factors described below, a deferral of them is warranted.

As discussed above, traditional ratemaking is designed around some balance between the regulatory lag experienced by the company before new plant is included in rate base, and lag experienced by ratepayers of seeing the financial benefits of updating plant balances to recognize the depreciation that has occurred. Additionally, utilities typically bear the risk for changes to normal operating expenses between GRCs under traditional ratemaking, where there is an expectation that some operating expenses will increase while others will decrease. Because the closure of Boardman represented a significant reduction in costs associated with the now fully depreciated plant and operating cost savings, our authorization of a deferral here allows us to determine whether that change represents a major departure from the traditional ratemaking balance that warrants special ratemaking.

We recognize that we declined to establish a Phase II for the Faraday project based on that balance in traditional ratemaking.[95] With respect to the Boardman deferral, however, we are ultimately persuaded that the magnitude of the revenues collected, combined with other contextual factors, warrants a deferral with amortization subject to an earnings test. Whereas PGE's Faraday proposal would involve updating a single cost item outside of a rate case without considering all costs and revenues, our evaluation of the Boardman deferral with an earnings review offers a holistic view of the interplay of costs and revenues between rate cases.

Several contextual factors are relevant to our decision to authorize the Boardman deferral. First, as CUB contends, the creation of statutory rate adjustment mechanisms such as the RAC has impacted the traditional ratemaking balance by eliminating lag on new RPS-eligible generating resources. We agree that a principle of symmetry will be important to our regulatory approach during a period in which the generating fleet is transitioning. With more of PGE's generating projects eligible for recovery under the RAC in the future, we may need to evaluate how ratemaking should evolve on a forward-looking basis, to ensure that overall rates remain reasonable as more and more investments and expenses are added to rates without any balancing test. We find that authorizing the Boardman deferral here is consistent with and supportive of our desire to ensure a proper balance between the RAC's effect of adding most new plant to rate base automatically, while not updating PGE's rates to reflect depreciation that has occurred on

[95] *See supra* at 35-36.

its existing plant. With that said, we distinctly prefer that parties present us with forward-looking mechanisms for achieving this symmetry principle going forward. Notably, the sort of advance planning that may help preserve the balance is already underway in this case, as PGE moves Colstrip from base rates to Schedule 146, which will enable the removal of Colstrip from rates as soon as it is retired. Developing methods of advance planning for these major retirements will be a key element to ensuring symmetry in our resource transition. [96]

A second factor relevant to our decision to authorize the Boardman deferral is that PGE made use of cost recovery mechanisms to ensure that customers carried many of the additional costs associated with Boardman retirement. PGE's use of Schedule 145 to recover costs associated with Boardman outside of base rates served as a benefit to the company that makes us hesitant to reject the deferral of Boardman-related savings out of hand.

Finally, we note an intrinsic asymmetry of information about changing costs between GRCs that makes deferrals significantly more common for recovery of additional utility expenses than for revenues to be returned to customers. We find it important to try to mitigate that asymmetry of information, and due to the magnitude of the Boardman deferral, we find authorization under our discretionary standard is important and warranted here.

PGE asserts that we should not authorize the deferral because customers have not been harmed due to the offsetting effect of the plant placed in service since its last GRC. We agree with Staff and CUB that, when evaluating the magnitude of the event in order to determine whether to *authorize* the deferral, we do not consider whether there were any potentially offsetting costs. Under our analysis, that consideration (*i.e.*, whether any harm resulted) is addressed within the earning test, when *amortization* is considered, as discussed below.

In this case, our authorization of the Boardman deferral will allow us to evaluate, through application of an earnings test, whether the continued recovery of Boardman costs in rates resulted in ratepayers overpaying. If these deferred amounts were to be amortized, this outcome would mean that the amounts that would normally remain with the company in between rate cases (under standard ratemaking) would be refunded to customers, and PGE would also be required to absorb the lag associated with new capital investments during this period. Under these circumstances, it is thus important to determine whether rates continue to be reasonable despite the changes in underlying utility costs that come about from its new investments since its last rate case in light of its retirement of

[96] *See In the Matter of PacifiCorp, Application for Authority to Implement a Decommissioning Cost Recovery Adjustment and Coal Removal Mechanism*, Docket No. UM 2183 (proposing Schedule 92, Decommissioning Cost Recovery Adjustment).

Boardman. Here, applying an earnings test to this deferral will serve to ensure that the company does not inappropriately over-earn as a result the costs of Boardman remaining in rates after its retirement, in essence promoting the balance intended under traditional ratemaking. We find that the earnings test, provided by ORS 757.259(5), serves this critical role, and thus we subject the question of whether a refund is appropriate to an earnings test.

We disagree with CUB that ORS 757.355 precludes application of an earnings test in this case. ORS 757.225 requires that a utility collect rates as specified in the effective rate schedule, and states that "[t]he rates named therein are the lawful rates until they are changed as provided in ORS 757.201 to 757.220." Under those provisions, utilities must file tariffs or rate schedules for Commission approval, which may be subject to suspension and investigation to evaluate whether the proposed rate is fair, just, and reasonable. ORS 757.355, which addresses the exclusion of plant not presently providing service from rate base, must be read in the context of this statutorily established process for changing rates. Accordingly, we interpret ORS 757.355 as requiring the Commission to exclude any plant in service from rates at the time rates are set. We disagree that the retirement of plant between rate cases renders previously established lawful rates unlawful.

The undepreciated balance of Boardman was properly included in rate base when rates were established in 2018 and will be fully removed from the rates established in this case. The parties here do not suggest that the rates established in docket UE 335 should not have included the costs for Boardman at the time those rates were established. The Dreyer case cited by CUB addressed inclusion in rates of costs for plant that had already been retired at the time rates were established leading the court to determine the rates were "improperly calculated."[97] The circumstances here are different. Boardman costs were properly included in the rates established in 2018 while the plant was still in service. CUB argues that its interpretation of ORS 757.355 would not require the resetting of rates to adjust for ongoing plant retirements between GRCs, arguing this significant retirement is distinguishable from the retirements of lesser plant like poles. However, ORS 757.355 does not distinguish based on the size of the investment, and instead is most plainly read to apply to all plant. Interpreting the statute to require immediate removal of Boardman from rates upon its retirement would be inconsistent with decades of ratemaking practice and create an impractical result that would be difficult to implement. Rates would either need to be continually reset with each retirement, as PGE notes, or utilities would need to track and defer all retirements occurring between GRCs, to be credited back to customers in a subsequent rate case. Neither method is readily compatible with the statutory framework for changing rates.

[97] *Dreyer*, 341 Or 262.

We address the appropriate amortization review and earnings test for the Boardman deferral below.

3. Earnings Test and Amortization

a. Positions of the Parties

(1) PGE

(a) Amortization Review Process

PGE opposes opening a separate consolidated docket to consider the three deferrals together, arguing that doing so would confuse the issues. PGE contends that different parties have the burden of proof for the Boardman deferral, the deferrals involve different types of events (*i.e.*, stochastic and scenario events), and there is no relationship between the deferrals other than their large size and similar, but not identical, timeframes. PGE states that the company will file amortization applications this year after its 2021 Results of Operations Report is available and asserts that if the Commission wishes to handle amortization of the deferrals concurrently, it can require PGE to file for amortization at the same time and direct the three dockets to be resolved on the same schedule. PGE argues that if the Commission considers the deferrals in this case, the Commission should delay amortization of the wildfire and ice storm deferrals until ripe for amortization and direct that the earnings review will be based on the 2021 calendar year. PGE also disputes AWEC's contention that costs PGE is including in the wildfire deferral were incurred more than a year later and may not be appropriately tied to the 2020 wildfire event. PGE maintains that the company continues recovery work in burned areas, including removal of tens of thousands of burned trees, and that completing this work has been delayed by weather and availability of qualified tree removal personnel.

PGE opposes Staff's recommendation to conduct the earnings review by calendar year, and authorize amortization of the wildfire costs deferred in 2020 in this case. PGE contends that such a piecemeal approach will not 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. PGE also argues that the instance Staff cites to where the Commission performed year-by-year earnings review was for costs anticipated to be incurred over a 20-year period, and that with such a lengthy deferral, regular earnings reviews made sense.[98] Here, PGE argues, with deferrals of approximately two years or less, multiple reviews create unnecessary complication.

[98] PGE Opening Brief at 34, *citing In the Matter of Northwest Natural Gas Company, Mechanism for Recovery of Environmental Remediation Costs*, Docket No. UM 1635, Order No. 15-049 (Feb. 20, 2015).

PGE asserts that to properly address amortization, the Commission must review PGE's earnings during the deferral period or a period "reasonably representative of the deferral period."[99] PGE argues that the Boardman and wildfire deferrals both span from late 2020 into 2022, with the majority of the costs occurring in 2021, and the ice storm deferral covers February 15, 2021, through February 14, 2022. Thus, PGE contends 2021 is reasonably representative of the deferral period for all three deferrals. PGE recommends that the Commission conduct one earnings review for each deferral based on the 2021 calendar year, compare PGE's earnings to its AROE, and not impose a sharing requirement. PGE states that the 2021 Results of Operations Report will be available by May 1, 2022, and argues that any earnings review would need to consider the results of PGE's power cost adjustment mechanism.[100]

PGE contends that Staff's proposal appears to attempt to reduce the carrying charges on the entire deferral balances, but that the Commission only applies a lower rate after amounts have been approved for amortization. As a result, PGE argues that as long as the unamortized balance is at risk of recovery, then that balance should be earning interest at PGE's ROR, not the modified blended Treasury Rate (MBT). PGE also opposes AWEC's proposal to direct $15 million in annual amortization of the wildfire and ice storm deferrals, subject to refund. PGE contends that ordering amortization subject to refund should not reduce the interest rate on the deferral balance because the risk of non-recovery continues to exist for any amounts subject to refund. PGE contends that as long as the unamortized balance is at risk of non-recovery, it should continue to earn interest at PGE's ROR, not the MBT rate.

(b) Earnings Test

PGE opposes Staff's proposal to use an earnings test with a benchmark of 100 basis points below AROE, arguing that this ignores recent precedent where the utility's AROE, or in one instance the utility's authorized ROR (AROR), served as the benchmark in an earnings review. PGE also argues that Staff's proposal is asymmetric by applying the same below-ROE threshold for amortizing both credits and costs. PGE asserts that this is inconsistent with the Commission's prior statement that an "earnings test works to protect both the utility and its customers."[101] PGE states that 100 basis points below AROE is approximately $39 million, and argues that this is a significant amount to require the company to absorb, particularly when combined with Staff's proposed sharing mechanism. PGE recommends using its AROE, arguing that this is a reasonable and consistent standard that will be predictable and fair for both the company and its customers. PGE also argues that the parties to this case, including Staff, stipulated to

[99] *Id.* at 34, *quoting* OAR 860-027-0300(9).
[100] PGE/2300, Tooman-Batzler/9.
[101] PGE Prehearing Brief at 49, *quoting* Order No. 15-049 at 12.

maintain PGE's AROE at 9.5 percent, and that Staff has not explained why the earnings review should apply a different threshold.

PGE argues that if authorized, the Boardman deferral should also be subject to an earnings test, and that to do otherwise would be to ignore the effect of amortization on PGE's financial health. PGE contends that the Commission has stated that an earnings test "ensures that utilities are not to refund amounts to customers while earnings are below reasonable levels."[102]

PGE also opposes Staff's proposal for the company to absorb 10 percent of the prudently incurred deferred costs for the wildfire and ice storm deferral. PGE disputes that sharing is appropriate for emergency deferrals and argues that where there was "limited discretion in the work the company [w]as being required to do," the Commission previously rejected sharing, and found that application of the earnings test provided "sufficient incentives . . . to minimize expenses."[103] PGE asserts that for the wildfire and ice storm, the company was required to do a significant amount of work in a limited period of time following severe events that significantly impacted its system. PGE also asserts that for its pre-filed emergency deferral account, as approved, the deferred balance is subject to full utility recovery, pending a prudence review.[104]

(2) AWEC, CUB, and Staff

(a) Amortization Review Process

Staff recommends that the Commission address issues related to the amortization of all three deferrals, including the parameters of the earnings review and any sharing, as well as authorize amortization of amounts deferred in 2020 in this docket. Staff argues that the Commission previously applied a similar approach to a multi-year deferral for environmental remediation costs.[105] Staff argues that because PGE's 2020 Results of Operations Report is available, the Commission is able to conduct an earnings review for amounts deferred in 2020 and authorize amortization for any costs deemed prudent. Staff argues that because PGE's 2021 Results of Operations Report will not be available in time to conduct an earnings review for deferrals accrued in 2021 and due to concerns regarding the prudence of the costs PGE deferred in 2021 for the 2020 wildfires, Staff

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[102] PGE Opening Brief at 35, *quoting In the Matter of Idaho Power Company, Request for a General Rate Revision*, Docket No. UE 233, Order No. 13-416 at 12 (Nov. 12, 2013).
[103] PGE Prehearing Brief at 50, *quoting* Order No. 15-049 at 11.
[104] PGE Prehearing Brief at 50, *citing In the Matter of Portland General Electric Company, Application for a Pre-Filed Emergency Deferral of Costs Associated with Declared Emergencies*, Docket No. UM 2190, Order No. 21-309, Appendix A at 3 (Sep. 22, 2021).
[105] Staff Prehearing Brief at 23, *citing* Order No 15-049.

does not recommend addressing amortization in this case. Staff also argues that a full prudence review is required for the ice storm restoration costs.

CUB recommends that the Commission direct the amortization of the entire Boardman balance on a functionalized basis over three years for return to customers. CUB contends that, at a minimum, the Commission should authorize the Boardman deferral in this docket, and address amortization in docket UM 2119 or a separate contested case. In the alternative, CUB supports Staff's amortization proposal. CUB supports Staff's proposal to amortize the wildfire and ice storm deferrals by calendar year, arguing that once the amounts are approved for amortization, ratepayers will benefit because the applicable interest rate for amortization would decrease from AROR to the MBT rate. CUB supports Staff's proposal to authorize amortization of the prudently incurred costs deferred in 2020 to enable these accounts to shift to accruing interest at the MBT rate. CUB maintains that the Commission can address Staff's proposal for earnings tests and sharing in this proceeding while ongoing prudence concerns about post-2020 deferred costs can be reviewed in their respective deferral dockets in the future.

AWEC requests that the Commission open a consolidated docket to review deferred costs and establish appropriate amortization schedules for the three deferrals. AWEC argues this will support efficiency and further the public interest. AWEC argues that during the course of this proceeding, corrections to calculations and updates have resulted in material changes in the balances of the deferrals. AWEC also argues that it has concerns regarding the ongoing accrual of costs in the wildfire deferral, which AWEC identifies as an 84 percent increase in vegetation management costs since September. AWEC argues a future proceeding will allow time for the parties to fully review these costs. In this docket, AWEC recommends amortizing $15 million annually for the wildfire and ice storm deferrals, subject to refund in this case and reducing the interest rate applicable to the remaining balances to the MBT rate. AWEC contends that amortization of the $15 million would result in roughly equal balances for these deferrals as compared to the Boardman deferral. AWEC argues that if the Commission does not reduce the applicable interest rate, it should take no action on the amortizations in this case.

(b) Earnings Test

Staff recommends that for each calendar year, the earnings review for the deferrals be conducted after aggregating the deferrals applicable for that year to evaluate the impact of the net amount on PGE's earnings. Staff recommends that the Commission adopt an earnings test benchmark of 100 basis points below PGE's AROE. Under Staff's proposal, PGE could amortize deferred costs only to the extent the amortization does not increase PGE's earnings above this level (costs) or decrease PGE's earnings below this level (credit). Staff argues that its proposal provides an incentive for PGE to minimize recovery costs for catastrophic events and ensures customers are refunded as much of the amounts collected for Boardman as possible, without endangering the financial health of the company. Staff contends that in arguing for an earnings test benchmark at AROE, PGE relies upon inapplicable precedent that did not relate to a deferral for a natural event. Staff argues that its proposed benchmarks are consistent with Commission precedent to allow amortization to the extent necessary to brings earnings up to the bottom of a reasonable range and allow amortization of a refund to the extent the refund did not cause earnings to fall below a reasonable range.[106]

Staff also proposes applying 90/10 sharing to the ice storm and wildfire deferrals, with PGE absorbing ten percent of the prudently incurred deferred costs, as an incentive for PGE to prudently manage restoration costs. Staff proposes to apply sharing before the earnings test, meaning that only 90 percent of the prudently incurred amounts that have been approved for deferral would subject to the earnings test. Staff disputes PGE's reliance on the Commission's decision declining to impose sharing for environmental remediation costs. Staff argues that there was no need for an incentive associated with remediating damage done many years prior by a technology no longer in use. Here, Staff contends that the mechanism for recovering storm restoration costs should incent PGE to harden its system to mitigate the impact of future storms.

Staff does not recommend sharing for the Boardman deferral, arguing that allowing PGE to keep a percentage of the deferred amounts would not incentivize behavior that benefits customers. Staff notes that Idaho Power sought a rate change in Idaho soon after Boardman ceased operating to eliminate Boardman from its revenue requirement, and argues that allowing PGE to benefit from not taking a similar action by allowing PGE to keep a portion of the amounts it collected from customers for Boardman would be unfair.

CUB asserts that the Commission has broad discretion in applying an earnings test, and has found that "earnings test treatments should be designed to further public policy goals related to the specific deferral."[107] CUB argues that the earnings test should recognize the circumstances that gave rise to the deferral, which it asserts includes a systematic overcollection built into Oregon ratemaking. CUB contends that PGE has avoided regulatory lag on nearly all of its recent generating assets and that most of its future investments will be eligible for dollar-for-dollar cost recovery through the RAC. CUB contends that with no regulatory lag on the front end, and regulatory lag occurring on the back end, customers will overpay for generation investments. CUB also argues that when a change in costs is mandated, due to regulatory, legislative, or statutory direction,

[106] Staff Opening Brief at 22-23, *citing In the Matter of the Revised Tariff Sheets Filed by Portland General Electric Company to Implement the Provisions of Order No. 91-1781 and Application of Portland General Electric Company for an Order Approving Deferral of Costs*, Docket Nos. UE 82 and UM 445, Order No. 93-257 at 11-12 (Feb. 22, 1993).
[107] CUB Opening Brief at 10, *quoting* Order No. 93-257 at 11-12.

the Commission frequently does not require that traditional deferral criteria be met or an earnings test be applied.

CUB notes that in adopting a settlement in docket UM 1920 regarding deferred tax benefits associated with the U.S. Tax Reconciliation Act, the Commission did not apply its own earnings test, but indicated that an earnings test at AROE would have reduced the tax benefit being returned to customers, which would have been improper given the circumstances of the deferral.[108] CUB argues circumstances are similar here because docket UM 1920 addressed the excess revenues collected to pay for taxes after changes reduced federal tax rates and the Boardman deferral is tracking revenues that customers paid in excess of Boardman's costs after closure. CUB argues that the Commission approved a refund of the deferred amounts in docket UM 1920 and should do the same here.

b. Resolution

Having addressed the threshold authorization for all three deferrals, we will establish the parameters of the earnings tests to be applied to each deferral, with further process to occur in the individual deferral dockets. We decline to open a consolidated docket, finding that any future review of costs, implementation of the earnings tests, and calculation of the amortization schedules for the three deferrals may be addressed in their existing dockets, consistent with our order here.

We are unpersuaded that there is reason to wait until PGE's 2021 earnings are available to begin addressing the costs of these multi-year deferrals. Under our rules, "[t]he period selected for the earnings review will encompass all or part of the period during which the deferral took place or must be reasonably representative of the deferral period."[109] Under a year-by-year method for the three deferrals, we are able to evaluate the costs deferred in a year against the company's earnings in the same year. We find that the approach appropriate for these significant deferrals that extend beyond a year is to match the costs with the earnings for each year. PGE's proposal to use 2021, while perhaps simpler, would not allow the same evaluation of costs relative to earnings in the same period. Instead, it would compare earnings from a year to expenses that were not even incurred within that year.

Our approach of allowing for amortization of deferred amounts after subjecting them to an earnings test for the specific year in which they were incurred reduces the interest that might otherwise accrue on a large multi-year deferral. This does not reduce the interest

[108] CUB Opening Brief at 11, *citing In the Matter of Portland General Electric Company, Application for Authorization to Defer Benefits Associated with the US Tax Reconciliation Act*, Docket No. UM 1920, Order No. 18-459 (Dec. 4, 2018).
[109] OAR 860-027-0300.

rate on the remaining balance associated with subsequent years but allows us to address whether costs are subject to amortization year-by-year, reducing the rate for that year's costs rather than continuing to accrue interest at the higher rate. We will not adopt AWEC's proposal to begin amortization of the wildfire and ice storm deferrals, subject to refund, and reduce the interest rate on the entire balance of the deferrals to the MBT rate. Deferrals are subject to interest at AROR until deemed subject to amortization.[110] Until the costs are reviewed and determined to be eligible for amortization, the risk of non-recovery remains.

The 2020 wildfires and 2021 ice storm were significant and unprecedented events, and we conclude that the earnings test should be applied to allow amortization of costs to the extent that PGE's earnings may remain near, but not precisely at its AROE. Here, these deferrals relate to costs of events that represented serious risks posed to and harm and cost sustained by both PGE and its customers. We agree with Staff that PGE should absorb some of that risk associated with its operations in challenging circumstances, rather than allowing the operation of an earnings test to preserve earnings at the precise level of PGE's AROE. However, we conclude that Staff's proposal of 100 basis points below AROE would, in practice, guarantee that these catastrophic events resulted in the company earning at the bottom of the range Staff argues is reasonable, and thus seem to suggest a Commission expectation that extreme and unprecedented events will inevitably lead to utility financial performance at the bottom of the range that Staff has argued here is reasonable. Recognizing that multiple large emergency deferrals will be addressed over the next few years, we are mindful that an earnings test of 100 basis points below AROE would virtually ensure that earnings remain at this level, regardless of what other cost saving measures utilities might take. For unexpected and unprecedented events of such substantial magnitude, we find that it is appropriate for customers to also bear some costs of restoration, without requiring that utility earnings first decline by 100 basis points. Accordingly, we adopt an earnings test at 20 basis points below AROE to be applied to the wildfire and ice storm deferrals. The effect of this will be that PGE will likely bear some of the costs of the wildfire and ice storm deferrals to the extent it can do so while maintaining a level of return near—but not precisely at—its AROE, with customers also contributing to restoration costs.

The purpose of our approach for the wildfire and ice storm deferrals is to require PGE to bear a portion of the deferred wildfire and ice storm costs to the extent its earnings, after incurring those costs, are above 20 basis points below its AROE. Our intent in applying an earnings test is not to enable PGE to *reach* this earnings threshold as a result of amortizing these deferrals. Because the purpose of deferred accounting is to allow a utility to maintain a level of return that the company would have otherwise achieved

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[110] *In the Matter of Public Utility Commission of Oregon, Staff Request to Open an Investigation Related to Deferred Accounting*, Docket No. UM 1147, Order No. 06-507 at 4 (Sep. 6, 2006).

without the events that justified the deferral, application of the earnings test must consider how a utility's earnings would be affected if it had to instead absorb the deferred expenses. As a result, a utility earning under its AROE will not then increase its earnings by amortizing the deferred expenses; rather, recovery of deferred costs serves to avoid a further reduction in earnings.

For the Boardman deferral, we find that the earnings test should provide for a refund only in the event that the company is demonstrated to have earned above its AROE. Boardman's 2020 retirement date had been well known to PGE, Staff, and all of the parties for a decade, and extensive planning and ratemaking took place for other elements of its retirement. PGE operated under its existing rates in such a way as to absorb regulatory lag in excess of that offset by the Boardman costs recovered in rates and controlled costs to achieve its AROE. We believe PGE should retain some benefit of using Boardman's retirement to help it manage costs between rate cases and avoid filing a rate case during the height of the COVID-19 pandemic, except to the extent that retaining Boardman revenues in rates caused PGE to retain earnings above its AROE. Accordingly, we adopt an earnings test at AROE to be applied to the Boardman deferral.

We decline to adopt Staff's proposal to net the three deferred amounts prior to application of an earnings test. Netting the deferred amounts prior to an earnings test would seem to assume first that amortization of each deferral is appropriate. We instead rely on the earnings test to first determine the appropriateness of amortization. Thus, netting prior to that step would be inappropriate. We conduct the earnings review to evaluate the effect of the deferrals on the company's financial health, and in light of the policies addressed above, and order that this step be completed before netting any amortizations that are owed to or collected from customers.

We also decline to adopt Staff's proposal for PGE to absorb 10 percent of the prudently incurred costs in the wildfire and ice storm deferrals. We consider such measures, on a case-by-case basis, with a purpose of furthering public policy goals related to the deferral.[111] The earnings test described above is designed to ensure that PGE shares some portion of these expenses when its earnings will still remain near its AROE after absorbing such costs, with customers also contributing to restoration costs when appropriate. We have designed the earnings test to achieve our intended balance of sharing and will not direct further sharing here. We are concerned that requiring a sharing of expense (as opposed to a sharing based on earnings) could serve an unintended consequence of causing a utility to withhold expense or efforts at restoration, when we believe it important to promote those efforts to the extent exigent at the time. Additionally, as addressed above, PGE will continue to bear some risk of restoration

[111] *See* Order No. 93-257 at 12.

costs for events that fall within its Level III outage mechanism and are not related to a declared state of emergency.

We note that in opposing Staff's sharing proposal, PGE argues that its pre-filed emergency deferral account balance is subject to full recovery, pending a prudence review.[112] In adopting Staff's recommendation to authorize that deferral account, it was our expectation that "review of the deferred expenses requested for amortization would be subject to the same standard of review for all other deferrals."[113] We disagree that our authorization of the deferral account constrained in any way the future amortization review of those costs, including application of an earnings test or other proposals for sharing.

We direct PGE to submit compliance filings applying the earnings tests set forth above to the 2020 wildfire and Boardman deferrals in their respective dockets. We note that the record of this proceeding indicates the potential for some differences in understanding with regard to the application of the earnings tests, and the calculation of a utility's earnings for purposes of applying an earnings test. In particular, the illustrative earnings review scenarios presented in PGE's closing brief demonstrated amortization of deferred expenses as increasing the company's earnings, which would be inconsistent with our approach set forth above.[114] Specifically, we intend to subject PGE's deferrals discussed herein to an earnings test that determines whether the company could bear the deferred costs, or a portion of them (whether they be deferred expenses from wildfire or deferred credits to customers related to Boardman) and still have its earnings at a level allowed by the thresholds we set in this order. As described above, we have concerns that PGE's earnings as represented in the hypotheticals PGE provided in its closing brief may not be the correct way to make that determination. Accordingly, we anticipate that application of the earnings test set forth above may require further inquiry into how PGE presents its earnings in its annual Results of Operations Reports. We also recognize a potential need for clarification regarding other details of applying the earnings tests that may arise, but that we did not reach in this order. We will address any further issues with respect to the earnings tests, as well as the remaining prudence review, any netting to account for the undepreciated investment in damaged/replaced plant no longer used and useful, and applicable amortization periods in the individual dockets.

PGE shall submit compliance filings for 2021 and 2022, applying these earnings tests to the wildfire, ice storm, and Boardman deferrals for that year once its earnings are available for each year.

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[112] PGE Prehearing Brief at 50, *citing* Order No. 21-309, Appendix A at 3.
[113] No. 21-309, Appendix A at 3.
[114] PGE Closing Brief at 47.

E. Schedule 90 Subtransmission Rate

1. Introduction

PGE's existing Schedule 90 is available to customers whose facility capacity exceeds 4,000 kilowatts (kW) and whose aggregate energy consumption exceeds 100 average megawatts (MWa). PGE proposes to reduce the aggregate energy consumption threshold to offer service to customers whose consumption exceeds 30 MWa, with a second set of energy prices for customers whose aggregate energy consumption exceeds 250 MWa. PGE explains that this would provide a lower threshold for new customers that are significantly larger than existing Schedule 89 customers. PGE also explains that the rate design for Schedule 90 is similar to Schedule 89, but with higher customer charges. PGE states that the only customer currently on Schedule 90 is its largest customer and that the benefits of volume and load factor associated with this individual customer are significant for the remainder of PGE's customer base. PGE explains that as new and prospective customers with large loads and high load factors enter its service territory, the company seeks to recognize the beneficial characteristics of these customers through this proposed modification to Schedule 90. AWEC argues that PGE should implement a subtransmission rate for Schedule 90. Staff and AWEC agree that because Schedule 89 includes a subtransmission rate, there is no reason Schedule 90 should not also include this option. PGE opposes introducing a subtransmission rate in this GRC and proposes addressing it either in the company's next rate case or in a stakeholder process to address the appropriate terms.

2. Positions of the Parties

a. PGE

PGE opposes introducing a subtransmission rate for Schedule 90 at this time, arguing that offering this rate raises cost and safety issues that should be addressed before the rate is offered. PGE proposes studying this issue further and addressing it in a future rate case. PGE argues that the details of any subtransmission service and how to design a rate that is most useful for modern customers need to be studied and carefully crafted. PGE contends that the contents of a schedule offering a subtransmission or transmission rate turn on multiple interrelated issues, including customer maintenance requirements, power quality, and a rate to match those terms. PGE argues that this would also provide the opportunity to discuss whether other types of service, such as transmission service, would be preferable because the subtransmission service offered under Schedule 89 is a non-networked service that may be inadequate to provide the reliability and service quality certain industries with more modern equipment require.

PGE argues that a customer on a subtransmission rate builds and owns the substation used to serve its load, and that while these substations must comply with minimum safety standards when built, there is no requirement for customers to upgrade their substations as safety standards change. PGE states it has experienced numerous issues with legacy subtransmission customers where the customer has failed to properly maintain a substation or neglected meaningful safety issues.

PGE also argues that a Schedule 90 subtransmission rate could create upward price pressure on other customer classes, explaining that because these customers typically bypass distribution substations, they pay about half the distribution rates paid by customers served by secondary and primary service. PGE maintains that 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. Finally, PGE questions the demand for this option, arguing that the company has five legacy customers on the Schedule 89 subtransmission rate, and has had no new subtransmission service initiated in the last 16 years.

b. AWEC

AWEC argues that with PGE proposing to lower the eligibility threshold for Schedule 90 from 100 MWa to 30 MWa to make this schedule available to more customers, it is reasonable to expect newly eligible customers to be interested in a subtransmission rate. AWEC notes that it has members that have expressed interest in a subtransmission rate for Schedule 90, particularly at the reduced eligibility threshold proposed by PGE. Given the existing interest, AWEC argues that the low historical demand for subtransmission service that PGE points to is immaterial. AWEC argues that there is no rational basis for why a customer who could now request subtransmission service under Schedule 89 should not be able to request the same service under Schedule 90 going forward.

AWEC testifies that subtransmission rates are common options for large customers across the U.S.[115] AWEC testified that subtransmission is a distribution delivery voltage that large customers typically consider when obtaining distribution service because energy metered at the subtransmission level has fewer line losses. Because this service typically bypasses distribution substations, the associated rate typically excludes substation costs and adjusts other charges to account for the lower line losses. AWEC states that offering a subtransmission rate allows customers more flexibility in how they design and utilize their electric service and does not impose any material costs on PGE or affect any other customer class. AWEC asserts that offering a Schedule 90

[115] AWEC/400, Kaufman/23, *citing* Central Maine Power Company, Rate LGS-ST-TOU, Large General Service – Subtransmission – Time-of-Use; New York State Electric & Gas Corporation, 3S – Non-Residential Subtransmission Service with Demand; and Southern California Edison, Schedule TOU-8 Sheet, Time-of-Use-General Service-Large.

subtransmission rate has the potential to reduce costs for all customers by encouraging the development of large customers in the service territory. AWEC argues that Schedule 90 subtransmission customers would still contribute substantially to fixed costs through generation charges and A&G costs, benefitting all customers.

AWEC also argues that PGE has failed to provide evidence in support of its claim that offering subtransmission for Schedule 90 could introduce safety and reliability issues to the bulk electric system. AWEC contends that PGE's testimony describes issues experienced at two customer-owned substations but argues that PGE's witness was unable to identify any safety or reliability impacts to the bulk electric system from those instances.[116] AWEC also argues that the company did not submit into the record any studies to support the claim that that subtransmission service results in reliability concerns. AWEC argues that if the potential for safety and reliability issues from customer-owned substations is such a concern, it is unclear why PGE and other utilities currently offer subtransmission service or why PGE has not made a filing to raise these concerns for existing Schedule 89 customers. AWEC does not oppose establishing safety standards for customer-owned substations consistent with those applicable to PGE. AWEC contends that a condition requiring Schedule 90 customers to maintain their substations to the same standards as PGE could be included in the tariff.

AWEC disputes PGE's claim that Schedule 90 customers could create upward price pressure on other customer classes, noting the PGE's witness recognized that Schedule 90 customers would pay their full cost of service.[117] AWEC also argues that when a Schedule 90 customer builds its own substation, PGE would not incur the costs of building a dedicated PGE-owned substation that would otherwise be required, and would avoid the additional rate base. AWEC contends that any of PGE's concerns about potential cost shifting from Schedule 90 customers moving to direct access can be addressed in establishing an appropriate transition charge. AWEC, however, notes that given the cap on PGE's long-term direct access program, there is essentially no risk of a Schedule 90 customer transitioning to direct access until docket UM 2024 is concluded. AWEC argues that there is adequate time for any potential issues to be investigated in dockets UM 2024 and AR 651, given that any prospective Schedule 90 subtransmission customers would need to build and energize its facilities, and would be subject to five years of transition charges.

AWEC argues that it calculated a subtransmission rate for Schedule 90 using the same methodology that PGE uses to calculate the Schedule 89 subtransmission rate, and that PGE did not raise any concerns with AWEC's rate calculation method, and thus has failed to show AWEC's proposal is not fair, just, and reasonable.

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[116] AWEC Opening Brief at 10, *citing* Tr. at 13 (Feb. 10, 2022).
[117] *Id.* at 11, *citing* Tr. 17-18.

3. Resolution

PGE proposes to expand Schedule 90 to offer service to customers whose aggregate consumption exceeds 30 MWa and who maintain a load factor of over 80 percent for each account. Under PGE's proposal, Schedule 90 would include a second set of energy prices for customers whose aggregate energy consumption exceeds 250 MWa. No party opposes PGE's proposal. Reducing the threshold for Schedule 90 eligibility will provide customers with additional choice and flexibility, and we find these changes to be reasonable.

AWEC and Staff recommend that PGE include a subtransmission rate for Schedule 90. We agree that customers eligible for Schedule 90 under the newly reduced threshold should also have the option of subtransmission service, particularly in light of the indicated interest.[118] We find that limiting new Schedule 90 customers to taking primary service via PGE-owned substations is inconsistent with what is available to them today.

PGE argues that subtransmission service implicates safety and cost-shifting issues that should be addressed before the rate is offered, recommending that the company address this in its next GRC. PGE states that while a customer substation must satisfy the same requirements as PGE-owned substations at the time of connection, there is no requirement for customers to upgrade their substations as safety standards change. PGE provided some evidence of impacts to subtransmission customers in instances where the customer failed to properly maintain its substation or neglected meaningful safety issues.[119] To the extent that subtransmission service has the potential to cause safety and reliability issues due to customer ownership of substations, that risk already exists under of Schedule 89 and must be addressed expediently. We note that because Schedule 89 is available to customers with demand of greater than 4000kw, any prospective customers that are eligible for Schedule 90 would still be able to choose subtransmission if they remained on Schedule 89. Ensuring ongoing compliance with safety standards at customer-owned substations should be addressed in the near term, but this concern does not justify delaying the implementation of a Schedule 90 subtransmission rate.

While PGE also raised concerns regarding cost shifting, those concerns are unsupported on the record. As AWEC notes, any potential cost shifting from a Schedule 90 customer going onto direct access can be addressed with the development of appropriate transition charges. Accordingly, we find no reason to delay the implementation of a Schedule 90 subtransmission rate until the company's next GRC.

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[118] AWEC/400, Kaufman/22. AWEC testified that it has members with interest in subtransmission service at the reduced threshold for Schedule 90.

[119] Tr. at 13; PGE/3000, Macfarlane-Tang/22.

PGE also argues that the details of a schedule offering a subtransmission or transmission rate will depend on a variety of interconnected issues, including customer maintenance requirements, power quality, and a rate to match those terms. If, as PGE anticipates, prospective Schedule 90 customers will be seeking a higher level of reliability than can be provided via non-networked subtransmission service as is provided under Schedule 89, that need not foreclose the Schedule 90 subtransmission option for customers who are seeking subtransmission service.[120] Additionally, PGE remains free to develop and propose a transmission rate tailored to the needs of customers seeking that type of service, if there is interest.

We recognize the tension between ensuring that prospective customers are aware of and able to evaluate the Schedule 90 subtransmission option as the reduced threshold is made available and allowing PGE time to add details to this tariff offering, including the additional safety and maintenance standards that PGE has argued are necessary. To avoid delay and encourage swift action by PGE, we conclude that PGE must initially offer subtransmission service under Schedule 90 as advocated by AWEC here, to be effective May 9, 2022. PGE is encouraged to replace this offering as soon as it has developed a modernized tariff. AWEC correctly notes that any Schedule 90 subtransmission customers will take some time to connect to the system. Additionally, any such customers would be subject to PGE's Facility Connection Requirements for Loads at the time of connection.[121] We find there will be sufficient time for PGE to develop and implement the necessary tariff revisions to ensure that appropriate standards apply to all customer-owned substations on an ongoing basis prior to the time any Schedule 90 subtransmission customer is likely to take service. As PGE notes, that tariff modernization process should also consider how compliance with applicable standards may be enforced.[122] Because the concerns PGE expressed apply to both Schedules 89 and 90, we encourage PGE to work with stakeholders to modernize the subtransmission rate under both schedules.

No party raised concerns with AWEC's proposed method to calculate a Schedule 90 subtransmission rate, which is based on the same method PGE uses for Schedule 89.[123] PGE describes Schedule 90's rate design as similar to Schedule 89, but with higher customer charges.[124] We find that AWEC's method is reasonable for purposes of an interim rate. We direct PGE to include in its compliance filing, for effect May 9, 2022, Schedule 90 inclusive of a subtransmission rate, calculated as proposed by AWEC, with

[120] Tr. at 15, 21, 23-24. PGE anticipates potential Schedule 90 subtransmission customers would be seeking a high level of reliability via a networked substation, which would be subject to a transmission rate, and not offered via subtransmission service.
[121] Tr. 15-16; PGE/3000, Macfarlane-Tang/22; PGE/3003, Macfarlane-Tang.
[122] Tr. at 16.
[123] AWEC/200, Kaufman/51.
[124] PGE/1200, Macfarlane-Tang/14, 15, 32-33.

the understanding that PGE may propose further revisions when it files a revised tariff to address the issues it raised in this case.

F. Schedule 150

1. Positions of the Parties

a. PGE

PGE proposes to recover deferred costs associated with its transportation electrification (TE) pilots under Schedule 150. PGE explains that Schedule 150 currently collects a charge to support TE in accordance with Section 2(2) of HB 2165, with costs allocated to all customers, including direct access customers, based on total revenues, including generation revenues imputed to direct access customers.[125] PGE proposes to expand Schedule 150 to recover the deferred TE pilot costs under Schedule 150's current allocation methodology. PGE requests approval of its proposed modification to Schedule 150 in this case, noting that these issues will be revisited in docket UM 2024, the Commission's current direct access investigation. PGE opposes waiting until the conclusion of docket UM 2024 before deciding on the allocation of these costs, arguing that amortization of the costs of these pilots should begin before that docket is concluded.

PGE contends that it is seeking an interim cost allocation methodology, substantially similar to that adopted by the Commission in the context of community solar.[126] PGE argues that cost causation principles support its proposal because TE is a legislative goal to be achieved for the benefit of all Oregonians, and thus the costs should be shared as broadly and equitably as possible. PGE asserts that its TE efforts support statewide decarbonization goals and long-term load-growth through acceleration of EV adoption, benefitting all Oregonians through climate-change mitigation and improved public health and safety. PGE maintains that 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.

PGE argues that the Commission must protect all customers by ensuring that customers departing PGE's supply service for direct access pay their fair share of system costs, including costs related to public policy directives. PGE contends that the legislature specifically recognized that direct access customers should contribute to TE investments in HB 2165, by requiring utilities to collect a monthly meter charge from all customers

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[125] *See PGE Advice No. 21-26, Schedule 150 Transportation Electrification Cost Recovery Mechanism* (approved Dec. 28, 2021).

[126] PGE Opening Brief at 38, *citing In the Matter of Portland General Electric Company*, Advice No. 20-09 (ADV 112), Schedule 136 Cost Recovery Mechanism, Docket UE 380, Order No. 20-173 at 2 (May 28, 2020).

served by the utility's distribution system, regardless of whether the customer purchases energy from the utility. PGE asserts that the same principles should apply to all TE costs.

PGE maintains that adoption of its proposal will minimize cost subsidization across different customer groups. PGE asserts that Calpine's methodology would ignore the size of the customer and its load in determining the amount of public policy benefit the customer receives and the costs it should bear, by focusing on the distribution revenue requirement. PGE contends that the practical result of Calpine's proposal would be that smaller customers would bear more of these costs.

PGE argues that even if SB 1547 mandated a specific cost allocation, it would apply only to investments made until September 25, 2021, when HB 3055 became effective.[127] PGE also argues that the advertising and rebate costs at issue here would not logically be allocated to PGE's distribution system revenue requirement in the first instance, so allocating them in proportion to a customer's share of responsibility for distribution system costs is not allocating these costs similar to the recovery of these types of distribution system investments.

b. Calpine

Calpine asserts that non-bypassable charges should include only: (a) costs that are associated with services or programs that provide benefits to all classes of customers, including direct access customers, or (b) costs that are imposed to recover costs of state mandates that require all customers to subsidize certain programs or activities. Calpine maintains that the non-bypassability determination and the manner of allocating any non-bypassable costs turns on the specific facts and circumstances of each set of costs, rather than identifying costs as related to a public policy objective. Here, Calpine asserts that PGE fails to explain how costs for TE distribution infrastructure are related to electric generation resources or PGE's generation supply, or how their relation to societal decarbonization efforts justifies imputing generation costs to direct access customers.

Calpine agrees that these deferred TE pilot costs should be non-bypassable but argues that they should be recovered from all customers in a manner similar to the recovery of distribution costs. Calpine contends that the deferred costs here, O&M for charging investments and rebates to customers for charging infrastructure, are fundamentally related to distribution investments used to deliver energy to growing loads associated with EVs. Thus, Calpine also contends that allocating these costs similar to distribution costs is consistent with proper ratemaking treatment.

[127] PGE notes that HB 3055 included the same superseding cost allocation language as HB 2165, but an earlier effective date of September 25, 2021, rather than January 1, 2022.

Calpine argues that because the costs at issue here include costs deferred between January 2018 and January 1, 2022, such costs were incurred under TE pilots designed and approved pursuant to Senate Bill (SB) 1547, and thus the more restrictive cost recovery provisions of SB 1547 control. Calpine argues that SB 1547 provided that such costs "[s]hall be recovered from all customers of an electric company in a manner that is similar to recovery of distribution system investments." Calpine asserts that relying on the more discretionary cost recovery language in HB 2165 is erroneous because it applies only to costs incurred after January 1, 2022.

Calpine proposes to directly assign costs specific to a customer class, to be recovered based on each class' distribution revenue requirement. Calpine contends that deferred costs that are not specific to a single class should be allocated to each class in proportion to each class's distribution revenue requirement. Calpine disputes that any cross subsidization would occur under its proposal, and argues that non-residential customers would pay the same distribution-based allocation for these deferred costs whether they purchase energy through direct access or from PGE as a cost-of-service customer.

Calpine also disputes that the recovery mechanism for these costs could be revisited in docket UM 2024. Calpine explains that PGE proposes to amortize these costs over one year, and that as a result, the recovery method approved in this case will be determinative for these deferred costs.

c. AWEC

AWEC opposes any allocation of the TE pilot costs 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. AWEC asserts that ORS 757.357(5) sets forth TE infrastructure measures that benefit utility customers and notes that PGE has failed to address ORS 757.357(5) in this case.[128] Specifically, AWEC contends that PGE has not specified or quantified the benefits associated with its TE efforts, or identified what, if any, other benefits to the electric system result from its EV pilot

[128] ORS 757.357(5):

> An infrastructure measure to support transportation electrification is a utility service and a benefit to utility customers if the infrastructure measure can be reasonably anticipated to: (a) Support reductions of transportation sector greenhouse gas emissions over time; and (b) Benefit the electric company's customers in ways that may include, but need not be limited to: (A) Distribution or transmission management benefits; (B) Revenues to utilities from electric vehicle charging to offset utilities' fixed costs that may otherwise be charged to customers; (C) System efficiencies or other economic values inuring to the benefit of customers over the long term; or (D) Increased customer choice through greater transportation electrification infrastructure deployment to increase the availability of and access to public and private electric vehicle charging stations.

programs. As a result, AWEC contends it is impossible to determine a fair and reasonable allocation of these costs to direct access customers. AWEC argues that where PGE has presented no evidence to support its proposed cost allocation, and that because PGE bears the burden of proof, there is no basis for adopting its proposal in this case. AWEC argues that the only appropriate course would be to investigate the cost allocation in docket UM 2024.

2. Resolution

PGE proposes to expand Schedule 150 to recover TE pilot costs deferred in dockets UM 1938 and UM 2003, initially authorized on April 23, 2018, and February 22, 2019, respectively.[129] The deferral in docket UM 1938 includes O&M costs for three TE pilot programs authorized in Order No. 18-054, a Tri-Met public transportation pilot, an education and outreach program, and the Electric Avenue pilot.[130] The deferral in docket UM 2003 includes O&M costs for residential and business EV-charging pilot programs authorized in Order No. 19-385. PGE identifies approximately $1.4 million in costs incurred through calendar year 2021.[131] PGE explains that it will continue incurring costs until at least until February 2024 for at least one of the pilots.[132]

SB 1547 provided that these costs shall be recovered "from all customers of an electric company in a manner that is similar to recovery of distribution system investments." As of September 25, 2021, pursuant to HB 3055, that language was modified to provide for cost recovery "from the retail electricity consumers of an electric company in a manner determined by the commission."

We find that the costs incurred prior to September 25, 2021, are subject to the cost allocation language contained in SB 1547. At the oral argument, Calpine recognized that allocation based on each class' proportion of distribution revenue requirement would be a simpler method than its original proposal, but still consistent with SB 1547.[133] AWEC also recognized that a method consistent with Calpine's recommendation would be appropriate for purposes of amortizing pre-September 25, 2021 costs.[134] We find that allocation of such costs based on the distribution revenue requirement is consistent with

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[129] *In the Matters of Portland General Electric Company, Application for Deferred Accounting for Costs and Revenues Associated with the Transportation Electrification Plan* (UM 1938)*, and Application for Deferral of Costs and Revenues Associated with the Electric Vehicle Charging Pilots* (UM 2003), Order No. 20-381 (Oct. 27, 2020).

[130] Deferred costs for the Tri-Met Mass Transit pilot include incremental costs related to procurement, management, and maintenance. Deferred costs for the education and outreach pilot include expenses associated with specialized trainings, builders and developers outreach, ride and drive events, and regional market transformation activities. Deferred costs for the Electric Avenue pilot are comprised of incremental procurement, software, engineering studies, outreach, maintenance and process expenses.

[131] Tr. at 25.

[132] Tr. at 27-28.

[133] March 4, 2022 Oral Argument at 3:20.

[134] March 4, 2022 Oral Argument at 3:23.

SB 1547, and avoids unnecessary complexity for the purpose of amortizing the pre-September 25, 2021 deferred costs.

We understand that PGE will continue to incur costs for the five existing pilot programs under the deferrals in dockets UM 1938 and UM 2003. We determine that the costs deferred under these ongoing pilots after September 25, 2021, and through the conclusion of these pilots, should also be allocated based on the distribution revenue requirement. These five pilots were developed and approved under SB 1547, and were justified based on the requirements of that statute. We reject PGE's proposal to apply the same cost allocation as applied to the HB 2165 surcharge to its existing EV pilot programs because PGE failed to address or demonstrate why a midstream change in allocation method is warranted for programs that were authorized under SB 1547, where a different legal construct and justification was applicable.

As proposed, Schedule 150 would provide for the recovery of "the expenses associated with transportation electrification pilots not otherwise included in rates." We find that the cost allocation for any future TE pilots will be subject to the more discretionary standard in HB 2165 and HB 3055, which makes clear that the Oregon Legislature intends that that all customers share these costs going forward.[135] Thus, for any other TE pilot programs subject to cost recovery under Schedule 150, we adopt PGE's proposed cost allocation on an interim basis, consistent with the surcharge, pending the conclusion of docket UM 2024.[136]

Accordingly, costs for the five existing pilot programs deferred in dockets UM 1938 and UM 2003 will be allocated based on the distribution revenue requirement. The costs for any future TE pilot programs subject to cost recovery under Schedule 150 will be allocated based on total revenues on an interim basis. PGE is directed to submit a revised Schedule 150 and revised calculation of the rate spread consistent with the directives of this order.

We acknowledge that we are in the midst of a transition in how TE programs come before us, how such programs are reviewed and approved, and the legal and technical bases for such programs. We also acknowledge that utilities may make a general shift from individual pilot and program offerings to a portfolio approach. As these changes occur, we recognize that we may need to revisit what constitutes appropriate cost allocation. While we adopt a cost allocation methodology for the currently-deferred pilot

[135] ORS 757.600 "Retail electricity consumer" means the end user of electricity for specific purposes such as heating, lighting or operating equipment, and includes all end users of electricity served through the distribution system of an electric utility on or after July 23, 1999, whether or not each end user purchases the electricity from the electric utility.

[136] *In the Matter of Portland General Electric Company, Advice No. 20-09 (ADV 112), Schedule 136 Cost Recovery Mechanism*, Docket UE 380, Order No. 20-173 at 2 (May 28, 2020) adopting the same cost-allocation methodology on an interim basis pending resolution of Docket UM 2024).

programs and we accept PGE's proposed interim methodology for any future programs, we invite the parties to consider in docket UM 2024 or other appropriate dockets whether modifications to the interim methodology may be justified going forward.

VII. ORDER

IT IS ORDERED that:

1. The partial stipulation between AWEC, CUB, Kroger, PGE, Staff, and Walmart filed on September 30, 2021, attached as Appendix A, is adopted.

2. The partial stipulation between AWEC, CUB, Kroger, PGE, Staff, and Walmart filed on December 2, 2021, attached as Appendix B, is adopted.

3. The partial stipulation between AWEC, CUB, Kroger, PGE, SBUA, Staff, and Walmart filed on January 18, 2022, attached as Appendix C, is adopted.

4. The partial stipulation between AWEC, Calpine, CUB, Kroger, PGE, SBUA, Staff, and Walmart filed on February 7, 2022, attached as Appendix D, is adopted.

5. Advice No. 21-18 filed on July 9, 2021, is permanently suspended.

6. Portland General Electric Company must file new tariffs consistent with this order, by 12:00 p.m., on May 2, 2022, to be effective May 9, 2022.

Made, entered, and effective Apr 25 2022.

Megan W. Decker
Chair

Letha Tawney
Commissioner

Mark R. Thompson
Commissioner

PUBLIC UTILITY COMMISSION OF OREGON

A party may request rehearing or reconsideration of this order under ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-001-0720. A copy of the request must also be served on each party to the proceedings as provided in OAR 860-001-0180(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480 through 183.484.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 394

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for 2022 General Rate Revision	**PARTIAL STIPULATION**

This Partial Stipulation ("Stipulation") is between Portland General Electric Company ("PGE"), Staff of the Public Utility Commission of Oregon ("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"), (collectively, the "Stipulating Parties"). Calpine Solutions is not a party to this Stipulation and does not oppose it.

PGE filed this general rate case on July 9, 2021. The filing included twelve separate pieces of testimony and exhibits. PGE also provided to Staff and other parties voluminous work papers in support of its filing. Since that time, Staff and intervening parties have submitted approximately 1,000 data requests obtaining additional information. A settlement conference was held on September 10, 2021 in this general rate case resulting in the settlement included in this Stipulation. The Stipulating Parties participated in this settlement discussion, and no other parties participated in the discussion. As a result of the discussion, the Stipulating Parties have reached a compromise settlement of the Cost of Capital related issues in this docket, as set forth below.

TERMS OF PARTIAL STIPULATION

1. This Stipulation resolves only the general rate case issues described below. For purposes of this settlement, the Parties agreed to an outcome informed by a set of calculations, but the Stipulating Parties agree that the assumptions and calculations set no precedent for either future rate case Cost of Capital component calculations or any other purpose outside this rate case.

2. Return on Equity

   a. Stipulating Parties agree to an overall Return on Equity (ROE) of 9.5 percent.

3. Capital Structure

   a. Stipulating Parties agree to a notional Capital Structure, Long-Term Debt to Common Equity ratio of 50 percent Long-Term Debt and 50 percent Common Equity.

4. Cost of Long-Term Debt

   a. Stipulating Parties agree to a Cost of Long-Term Debt of 4.125 percent, and

      i. Debt issued in Q4 of 2020 related to the trading losses will be added back to the cost of debt calculation.

      ii. The coupon rate on the expected November 15, 2022 debt issuance will be set at 3.68 percent.

      iii. Debt issued by PGE in November 2022 will not be prorated.

      iv. Should PGE issue debt late in 2021, the agreed upon long-term debt rate of 4.125 percent will not be updated.

5. Rate of Return

   a. The Stipulating Parties agree that the effect of this partial settlement is an overall Rate of Return (ROR) of 6.813 percent.

6. The Stipulating Parties recommend and request that the Commission approve the adjustments and provisions described herein as appropriate and reasonable resolutions of all issues related to cost of capital in this docket.

7. The Stipulating Parties agree that this Stipulation is in the public interest, and will result in rates that are fair, just and reasonable, consistent with the standard in ORS 756.040.

8. The Stipulating Parties agree that this Stipulation represents a compromise in the positions of the Stipulating Parties. Without the written consent of all of the Stipulating Parties, evidence of conduct or statements, including but not limited to term sheets or other documents created solely for use in settlement conferences in this docket, are confidential and not admissible in this instance or any subsequent proceeding, unless independently discoverable or offered for other purposes allowed under ORS 40.190.

9. The Stipulating Parties have negotiated this Stipulation as an integrated document. The Stipulating Parties seek to obtain Commission approval of this Stipulation prior to evidentiary hearings. If the Commission rejects all or any material part of this Stipulation, or adds any material condition to any final order that is not consistent with this Stipulation, each Stipulating Party reserves its right: (i) pursuant to OAR 860-001-0350(9), to present evidence and argument on the record in support of the Stipulation, including the right to cross-examine witnesses, introduce evidence as deemed appropriate to respond fully to issues presented, and raise issues that are incorporated in the settlements embodied in this Stipulation; and (ii) pursuant to ORS 756.561 and OAR 860-001-0720, to seek rehearing or reconsideration, or pursuant to ORS 756.610 to appeal the Commission's final order. The Stipulating Parties agree that in the event the Commission rejects all or any material part of this Stipulation or adds any material condition to any final order that is not consistent

with this Stipulation, the Stipulating Parties will meet in good faith within ten days and discuss next steps. A Stipulating Party may withdraw from the Stipulation after this meeting by providing written notice to the Commission and other Stipulating Parties.

10. This Stipulation will be offered into the record in this proceeding as evidence pursuant to OAR 860-001-0350(7). The Stipulating Parties agree to support this Stipulation throughout this proceeding and in any appeal and provide witnesses to support this Stipulation (if required by the Commission), and recommend that the Commission issue an order adopting the settlement contained herein. By entering into this Stipulation, no Stipulating Party shall be deemed to have approved, admitted or consented to the facts, principles, methods or theories employed by any other Stipulating Party in arriving at the terms of this Stipulation. Except as provided in this Stipulation, no Stipulating Party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding.

11. This Stipulation may be signed in any number of counterparts, each of which will be an original for all purposes, but all of which taken together will constitute one and the same agreement.

DATED this 30th day of September, 2021.

Jay Tinker

PORTLAND GENERAL ELECTRIC COMPANY

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

OREGON CITIZENS' UTILITY BOARD

ALLIANCE OF WESTERN ENERGY CONSUMERS

THE KROGER CO.

WALMART

PORTLAND GENERAL ELECTRIC COMPANY

/s/ Jill D. Goatcher

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

OREGON CITIZENS' UTILITY BOARD

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 394

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for 2022 General Rate Revision	**PARTIAL STIPULATION**

This Second Partial Stipulation ("Stipulation") is between Portland General Electric Company ("PGE"), Staff of the Public Utility Commission of Oregon ("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"), (collectively, the "Stipulating Parties"). Calpine Solutions did not take a position on the issues resolved by this Stipulation, therefore is not a party to this Stipulation but does not oppose it.

PGE previously filed a First Partial Stipulation in this docket resolving all issues related to Cost of Capital in this general rate case. After reaching that agreement the parties continued settlement discussions on November 5, 2021. The Stipulating Parties participated in these settlement discussions, and no other parties participated in the discussion. As a result of the discussions, the Stipulating Parties have reached a compromise settlement resolving several additional issues in this docket, as set forth below.

TERMS OF SECOND PARTIAL STIPULATION

1. This Stipulation resolves only the general rate case issues described below.

2. Integrated Operations Center (IOC), S-23

   a. Stipulating Parties agree to include $206.7 million of capital related to the IOC in this general rate revision. This is a $9.0 million reduction to PGE's original proposal and resolves all issues related to the IOC's costs.

3. Level III Outage Accrual, S-12

   a. Stipulating Parties agree to remove the February 2021 ice storm costs from the calculation of the Level III Outage Accrual. Stipulating Parties acknowledge that PGE is seeking recovery of this expense through a separate deferral. Consequently, PGE will reduce its 2022 forecast of Distribution operation and maintenance expenses (O&M) by $6,920,000.

   b. Stipulating Parties also agree to either support or not oppose the approval of PGE's deferral filed under Docket UM 2156 for the February 2021 ice storm emergency, but do not necessarily agree to the level of costs identified in PGE's deferral, whether recovery of all costs is appropriate, the appropriate interest rate, or the timing for amortization.

   c. Lastly, Stipulating Parties agree to the re-establishment of approximately $8 million to the Level III Reserve, which had previously been reduced by that portion of the 2021 February ice storm expenses and not included in PGE's initial filing in Docket UM 2156.

4. Working Capital, S-18

   a. Stipulating Parties agree to use an average of the prior three lead-lag study values from the last three general rate cases as the working capital percentage in this case, resulting in a working capital factor of 3.891 percent.

5. Miscellaneous Directors' Expenses, A-07 & C-05

   a. Stipulating Parties agree to resolve all issues regarding PGE's Board of Directors' expenses and offsite meeting costs with a reduction to administrative and general expenses (A&G) of $150,000.

6. Membership Costs, CAISO Membership, Meals & Entertainment, S-08, S-09, S-10

   a. Stipulating Parties agree to resolve all issues related to PGE's membership costs, CAISO membership and meals & entertainment with a reduction to A&G of $700,000.

7. Campground Revenue, C-04

   a. Stipulating Parties agree to an increase of Other Revenues associated with campground revenue of $165,000. Settlement of this item does not resolve OPUC Staff's issue S-11 regarding Other Revenues.

8. Research and Development (R&D), A-11

   a. Stipulating Parties agree there will be no adjustment to PGE's test year expense for this issue.

9. Trojan Decommissioning Costs – Schedule 136 Surcharge, A-26

   a. Stipulating Parties agree to no adjustment to PGE's filed case for this issue. Any issues associated with refunds and collections from the Department of Energy and 2019 customer collections not submitted to the Trojan decommissioning trust are not resolved by this Stipulation.

10. Accumulated Deferred Income Taxes (ADIT) Incentives, A-18

a. Stipulating Parties agree to reduce PGE's incentive-related ADIT by $5,761,000.

11. Two Capital Projects, S-03, S-04, A-12

a. Stipulating Parties agree that the investments associated with the Beaver Modernization Project (P36836) and the Excitation System Project (P36444) will be removed from this rate case because both projects have in-service dates that have been delayed past April 30, 2022. This will result in a reduction to capital of $10,522,085.

b. Stipulating Parties agree that this stipulation does not constitute any admission or agreement with AWEC's arguments regarding the prudence of the Beaver Modernization Project. Stipulating Parties agree that prudence of this project should be reviewed in a future proceeding when PGE seeks recovery of the investment.

12. Three Rate Base Items, S-22, A-20, A-23

a. Stipulating Parties agree to resolve the issues related to Fuel stock, ADIT – Boardman Removal, and Colstrip Smart Burn for a reduction to PGE's rate base of $10,500,000

13. Directors' Deferred Compensation Plan, A-05

a. Stipulating Parties agree to a reduction to PGE's A&G of $203,000 for the interest charge associated with the Directors' Deferred Compensation Plan.

14. Directors' and Officers' (D&O) Liability Insurance, A-06

a. Stipulating Parties agree to reduce PGE's test year expense for D&O Liability Insurance by $100,000 as an offset to potential premium increases that may be deemed associated with PGE's 2020 trading losses.

15. Oregon Corporate Activities Tax (OCAT), S-06

Stipulating Parties agree

a. to move OCAT to base rates in an amount of $8,375,000, and PGE agrees to provide a detailed calculation showing how the amount was derived.

b. that PGE's OCAT deferral (Docket UM 2037) will terminate as of the rate effective date of this general rate case.

c. that PGE will be able to update its 2022 forecast if the calculation methodology changes as a result of a prospective change in the underlying OCAT legislation, OCAT rulemaking by the Oregon Department of Revenue (ODOR), a judicial proceeding, or an ODOR policy decision. Further, if a change described above occurs after the rate effective date for this rate case, PGE will be required to defer a surcharge or credit to reflect the difference in calculation methodology and amortize the surcharge or credit in full until the rate effective date of PGE's next rate case. Stipulating Parties will support, or not oppose, PGE's deferral and amortization filings pending their review of the calculation details.

d. that PGE will not propose any updates to the 2022 forecast based solely on changes to input amounts of that forecast.

16. Schedule 146 Updates

a. Stipulating Parties agree to annual updates of Schedule 146 for Colstrip beginning on January 1st of each year, the rate effective date, to reflect the subsequent year's change in the Colstrip Power Plant Units 3 and 4 revenue requirement (Parts A, B, and C).

    i. Consistent with Montana laws and all applicable law, PGE agrees to vote 'no' on any capital investments intended to extend the life of the Colstrip plant past 2025. Notwithstanding the foregoing, Stipulating Parties agree that PGE is not obligated to so vote if in PGE's sole discretion such vote may result in any fines, penalties, adverse orders or rulings, undesirable outcomes or other punitive measures imposed on PGE.

ii. Stipulating Parties agree that this Stipulation will not prejudice AWEC's position in the current depreciation study docket (UM 2152) or other issues related to the Colstrip revenue requirement included in Schedule 146 discussed in AWEC's testimony.

iii. Stipulating Parties agree to the following language change to PGE's filed Schedule 146 Tariff:

DETERMINATION OF ADJUSTMENT AMOUNTS

The Adjustment Rates will be updated annually to reflect the subsequent year's change in the Colstrip Power Plant Units 3 and 4 ~~decommissioning revenue requirement and depreciation~~ revenue requirement (Parts A ~~and~~, B, and C). ~~Any additional updates (Part C) to this schedule can only be made pursuant to 1) the removal of Colstrip from regulated service, or 2) rate change requests effectuated through a separate docketed proceeding as allowable through Oregon Revised Statutes and Oregon Administrative Rules (e.g., through a general rate case).~~

iv. PGE agrees to make available the approved Colstrip O&M and capital budgets, as well as the associated revenue requirement calculation, for the next year for Parties' review by November 1 of each year or within seven (7) business days of the approval of the budget, consistent with the timing of PGE's Owners and Operators' agreement with the Colstrip co-owners.

v. Stipulating Parties agree to support or not oppose PGE's request for deferred accounting in support of decommissioning costs included in Part A and associated with the balancing account balance.

17. Stipulating Parties recommend and request that the Commission approve the adjustments and provisions described herein as appropriate and reasonable resolutions of all issues addressed in this Stipulation.

18. Stipulating Parties agree that this Stipulation is in the public interest, and will result in rates that are fair, just, and reasonable, consistent with the standard in ORS 756.040.

19. Stipulating Parties agree that this Stipulation represents a compromise in the positions of the Stipulating Parties. Without the written consent of all the Stipulating Parties, evidence of conduct or statements, including but not limited to term sheets or other documents created solely for use in settlement conferences in this docket, are confidential and not admissible in this instance or any subsequent proceeding, unless independently discoverable or offered for other purposes allowed under ORS 40.190.

20. Stipulating Parties have negotiated this Stipulation as an integrated document. The Stipulating Parties seek to obtain Commission approval of this Stipulation after initial briefs were filed but prior to evidentiary hearings. If the Commission rejects all or any material part of this Stipulation, or adds any material condition to any final order that is not consistent with this Stipulation, each Stipulating Party reserves its right: (i) pursuant to OAR 860-001-0350(9), to present evidence and argument on the record in support of the Stipulation, including the right to cross-examine witnesses, introduce evidence as deemed appropriate to respond fully to issues presented, and raise issues that are incorporated in the settlements embodied in this Stipulation; and (ii) pursuant to ORS 756.561 and OAR 860-001-0720, to seek rehearing or reconsideration, or pursuant to ORS 756.610 to appeal the Commission's final order. Stipulating Parties agree that in the event the Commission rejects all or any material part of this Stipulation or adds any material condition to any final order that is not consistent with this Stipulation, Stipulating Parties will meet in good faith within ten days and discuss next steps. A Stipulating Party may withdraw from the

Stipulation after this meeting by providing written notice to the Commission and other Stipulating Parties.

21. This Stipulation will be offered into the record in this proceeding as evidence pursuant to OAR 860-001-0350(7). Stipulating Parties agree to support this Stipulation throughout this proceeding and in any appeal and provide witnesses to support this Stipulation (if required by the Commission), and recommend that the Commission issue an order adopting the settlement contained herein. By entering into this Stipulation, no Stipulating Party shall be deemed to have approved, admitted or consented to the facts, principles, methods or theories employed by any other Stipulating Party in arriving at the terms of this Stipulation. Except as provided in this Stipulation, no Stipulating Party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding.

22. This Stipulation may be signed in any number of counterparts, each of which will be an original for all purposes, but all of which taken together will constitute one and the same agreement.

DATED this 2nd day of December, 2021.

PORTLAND GENERAL ELECTRIC COMPANY

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

OREGON CITIZENS' UTILITY BOARD

ALLIANCE OF WESTERN ENERGY CONSUMERS

THE KROGER CO.

WALMART

____
PORTLAND GENERAL ELECTRIC COMPANY

Jill Goatcher
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Portland General Electric Company
2022 Revenue Requirement Summary
($000)

	Revenue	Percent
Total Increase:	103,521	5.11%

	Base Business 2022	Blank	Total Results	Check			
	(1)	(2)	(3)				
1 Sales to Consumers	2,127,491	-	2,127,491	2,127,491	2,127,491	TRUE	OK
2 Sales for Resale	-		-		-	TRUE	OK
3 Other Revenues	29,511		29,511		29,511	TRUE	OK
4 Total Operating Revenues	2,157,002	-	2,157,002		2,157,002	TRUE	OK
5 Net Variable Power Costs	543,993		543,993		543,993	TRUE	OK
6 Production O&M (excludes Trojan)	126,068		126,068		126,068	TRUE	OK
7 Trojan O&M	93		93		93	TRUE	OK
8 Transmission O&M	19,874		19,874		19,874	TRUE	OK
9 Distribution O&M	145,849		145,849		145,849	TRUE	OK
10 Customer & MBC O&M	83,085		83,085		83,085	TRUE	OK
11 Uncollectibles Expense	6,943	-	6,943	0.3264%	6,943	TRUE	OK
12 OPUC Fees	8,628	-	8,628	0.4055%	8,628	TRUE	OK
13 A&G, Ins/Bene., & Gen. Plant	177,078		177,078		177,078	TRUE	OK
14 Total Operating & Maintenance	1,111,610	-	1,111,610		1,111,610	TRUE	OK
15 Depreciation	338,741		338,741		338,741	TRUE	OK
16 Amortization	59,713		59,713		59,713	TRUE	OK
17 Property Tax	83,814		83,814		83,814	TRUE	OK
18 Payroll Tax	16,503		16,503		16,503	TRUE	OK
19 Other Taxes	11,310		11,310		11,310	TRUE	OK
20 Franchise Fees	54,375	-	54,375	2.5558%	54,375	TRUE	OK
21 Utility Income Tax	92,808	-	92,808		92,808	TRUE	OK
22 Total Operating Expenses & Taxes	1,768,873	-	1,768,873		1,768,873	TRUE	OK
23 **Utility Operating Income**	388,129	-	388,129	388,129	388,129	TRUE	OK
24 **Rate Base**							

	Base Business 2022	Blank	Total Results		Check		
	(1)	(2)	(3)				
25 Avg. Gross Plant	11,600,118		11,600,118		11,600,118	TRUE	OK
26 Avg. Accum. Deprec. / Amort	(5,284,044)		(5,284,044)		(5,284,044)	TRUE	OK
27 Avg. Accum. Def Tax	(687,715)		(687,715)		(687,715)	TRUE	OK
28 Avg. Accum. Def ITC	-		-		-	TRUE	OK
29 **Net Utility Plant**	5,628,359	-	5,628,359		5,628,359	TRUE	OK
30 Misc. Deferred Debits	6,294		6,294		6,294	TRUE	OK
31 Operating Materials & Fuel	67,724		67,724		67,724	TRUE	OK
32 Misc. Deferred Credits	(73,887)		(73,887)		(73,887)	TRUE	OK
33 Working Cash	68,818	-	68,818	3.8905%	68,818	TRUE	OK
34 **Rate Base**	5,697,308	-	5,697,308		5,697,308	TRUE	OK
35 **Rate of Return**	6.813%		6.813%		6.813%		
36 **Implied Return on Equity**	9.500%		9.500%		9.500%		

		Base Business 2022	Blank	Total Results	Check		
		(1)	(2)	(3)			
37	Effective Cost of Debt	4.125%	4.125%	4.125%	4.1250%	TRUE	
38	Effective Cost of Preferred	0.000%	0.000%	0.000%	0.0000%	TRUE	
39	Debt Share of Cap Structure	50.000%	50.000%	50.000%	50.0000%	TRUE	
40	Preferred Share of Cap Structure	0.000%	0.000%	0.000%	0.0000%	TRUE	
41	Weighted Cost of Debt	2.063%	2.063%	2.063%	2.0625%	TRUE	
42	Weighted Cost of Preferred	0.000%	0.000%	0.000%	0.0000%	TRUE	
43	Equity Share of Cap Structure	50.000%	50.000%	50.000%	50.0000%	TRUE	
44	State Tax Rate	7.594%	7.594%	7.594%	7.5943%	TRUE	
45	Federal Tax Rate	21.000%	21.000%	21.000%	21.0000%	TRUE	
46	Composite Tax Rate	27.000%	27.000%	27.000%	26.9995%	TRUE	
47	Bad Debt Rate	0.326%	0.326%	0.326%	0.3264%	TRUE	
48	Franchise Fee Rate	2.556%	2.556%	2.556%	2.5558%	TRUE	
49	Working Cash Factor	3.891%	3.891%	3.891%	3.8905%	TRUE	
50	Gross-Up Factor	1.370	1.370	1.370	136.9854%	TRUE	
51	ROE Target	9.500%	9.500%	9.500%	9.5000%	TRUE	
52	Grossed-Up COC	8.569%	8.569%	8.569%	8.5693%	TRUE	
53	OPUC Fee Rate	0.4055%	0.406%	0.406%	0.4055%	TRUE	
	Utility Income Taxes						
54	Book Revenues	2,157,002	-	2,157,002	2,157,002	TRUE	OK
55	Book Expenses	1,676,065	-	1,676,065	1,676,065	TRUE	OK
56	Interest Deduction	117,507	-	117,507	117,507	TRUE	OK
57	Production Deduction	-		-	-	TRUE	OK
58	Permanent Ms	(14,248)		(14,248)	(14,248)	TRUE	OK
59	Deferred Ms	154,217		154,217	154,217	TRUE	OK
60	Taxable Income	223,461	-	223,461	223,461	TRUE	OK
61	Current State Tax	16,970	-	16,970	16,970	TRUE	OK
62	State Tax Credits	(10)		(10)	(10)	TRUE	OK
63	Net State Taxes	16,960	-	16,960	16,960	TRUE	OK
64	Federal Taxable Income	206,501	-	206,501	206,501	TRUE	OK
65	Current Federal Tax	43,365	-	43,365	43,365	TRUE	OK

	Base Business 2022	Blank	Total Results	Check		
	(1)	(2)	(3)			
66 Federal Tax Credits	-		-	-	TRUE	OK
67 Excess ADIT Reversal (ARAM)	(9,156)		(9,156)	(9,156)	TRUE	OK
68 Deferred Taxes	41,638	-	41,638	41,638	TRUE	OK
69 Total Income Tax Expense	92,808	-	92,808	92,808	TRUE	OK
70 Regulated Net Income	270,622		270,622			
71 Check Regulated NI			270,622			

Portland General Electric Company
2022 Revenue Requirement - Base Business
($000)

	Revenue	Percent
Total Increase:	103,521	5.11%

	At Current Rates	Sept. Load Forecast Delta	GRC Change for RROE	Proposed 2022	Non-NVPC Adjustments	NVPC Adjustments	Total Results
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1 Sales to Consumers	2,006,036	17,935	81,032	2,105,003	(10,949)	33,437	2,127,491
2 Sales for Resale	-			-	-	-	-
3 Other Revenues	29,346			29,346	165	-	29,511
4 Total Operating Revenues	2,035,381		81,032	2,134,349	(10,784)	33,437	2,157,002
5 Net Variable Power Costs	511,766			511,766	-	32,227	543,993
6 Production O&M (excludes Trojan)	126,068			126,068	-	-	126,068
7 Trojan O&M	93			93	-	-	93
8 Transmission O&M	19,874			19,874	-	-	19,874
9 Distribution O&M	152,769			152,769	(6,920)	-	145,849
10 Customer & MBC O&M	83,085			83,085	-	-	83,085
11 Uncollectibles Expense	6,547		323	6,870	(36)	109	6,943
12 OPUC Fees	8,135		401	8,537	(44)	136	8,628
13 A&G, Ins/Bene., & Gen. Plant	178,231			178,231	(1,153)	-	177,078
14 Total Operating & Maintenance	1,086,568		724	1,087,292	(8,153)	32,471	1,111,610
15 Depreciation	338,741			338,741	-	-	338,741
16 Amortization	59,713			59,713	-	-	59,713
17 Property Tax	83,814			83,814	-	-	83,814
18 Payroll Tax	16,503			16,503	-	-	16,503
19 Other Taxes	2,935			2,935	8,375	-	11,310
20 Franchise Fees	51,271		2,529	53,800	(280)	855	54,375
21 Utility Income Tax	67,679		25,835	93,513	(2,696)	23	92,808
22 Total Operating Expenses & Taxes	1,707,222		29,089	1,736,311	(2,754)	33,349	1,768,873
23 **Utility Operating Income**	328,159		69,878	398,038	(8,030)	88	388,129
				398,038			388,129
24 **Average Rate Base**							
25 Avg. Gross Plant	11,630,140			11,630,140	(30,022)	-	11,600,118
26 Avg. Accum. Deprec. / Amort	(5,284,044)			(5,284,044)	-	-	(5,284,044)
27 Avg. Accum. Def Tax	(681,954)			(681,954)	(5,761)	-	(687,715)

28 Avg. Accum. Def ITC	-		-	-	-	-
29 **Avg. Net Utility Plant**	5,664,142	-	5,664,142	(35,783)	-	5,628,359
30 Misc. Deferred Debits	6,294		6,294	-	-	6,294
31 Operating Materials & Fuel	67,724		67,724	-	-	67,724
32 Misc. Deferred Credits	(73,887)		(73,887)	-	-	(73,887)
33 Working Cash	71,984	1,227	73,210	(107)	1,297	68,818
34 **Average Rate Base**	5,736,257	1,227	5,737,484	(35,890)	1,297	5,697,308
35 **Rate of Return**	5.721%		6.938%		6.813%	6.813%
36 **Implied Return on Equity**	7.067%		9.500%		9.500%	9.500%

Muldoon - Gehrke - M

Non-NVPC Adjustment Detail

	All RevReq Sensitives	ROE	Cost of Debt	Comp Tax Rate	Working Cash	Revenue Sensitives	Total RevReq Sensitives	Excitation System	Beaver Modernization	OCAT	Level III Accrual	Directors' Def Compensation	D&O Ins	Directors' Expenses	R&D	ADIT-I
		9/30/21 Stipulation			12/2/21 Stipulation											
		S-1			S-18			S-3	S-4	S-6	S-12 / A-24 / C-3	A-5	A-6	A-7	A-11	
	(7,918)	-	(7,417)	-	(509)	-										
1 Sales to Consumers	2,097,085	2,105,003	2,097,586	2,105,003	2,104,494	2,105,003	(7,918)	(31)	(902)	8,690	(7,180)	(211)	(104)	(156)	-	
2 Sales for Resale	-	-	-	-	-	-										
3 Other Revenue	29,346	29,346	29,346	29,346	29,346	29,346										
4 Total Operating Revenues	2,126,430	2,134,349	2,126,932	2,134,349	2,133,839	2,134,349	(7,918)	(31)	(902)	8,690	(7,180)	(211)	(104)	(156)	-	
5 Net Variable Power Costs	511,766	511,766	511,766	511,766	511,766	511,766										
6 Production O&M (Excludes Trojan)	126,068	126,068	126,068	126,068	126,068	126,068										
7 Trojan O&M	93	93	93	93	93	93										
8 Transmission O&M	19,874	19,874	19,874	19,874	19,874	19,874										
9 Distribution O&M	152,769	152,769	152,769	152,769	152,769	152,769					(6,920)					
10 Customer & MBC O&M	83,085	83,085	83,085	83,085	83,085	83,085										
11 Uncollectibles Expense	6,844	6,870	6,845	6,870	6,868	6,870	(26)	(0)	(3)	28	(23)	(1)	(0)	(1)	-	
12 OPUC Fees	8,505	8,537	8,507	8,537	8,535	8,537	(32)	(0)	(4)	35	(29)	(1)	(0)	(1)	-	
13 A&G, Ins/Bene., & Gen. Plant	178,231	178,231	178,231	178,231	178,231	178,231						(203)	(100)	(150)	-	
14 Total Operating & Maintenance	1,087,234	1,087,292	1,087,238	1,087,292	1,087,288	1,087,292	(58)	(0)	(7)	64	(6,973)	(205)	(101)	(151)	-	
15 Depreciation	338,741	338,741	338,741	338,741	338,741	338,741							-			
16 Amortization	59,713	59,713	59,713	59,713	59,713	59,713										
17 Property Tax	83,814	83,814	83,814	83,814	83,814	83,814										
18 Payroll Tax	16,503	16,503	16,503	16,503	16,503	16,503										
19 Other Taxes	2,935	2,935	2,935	2,935	2,935	2,935				8,375						
20 Franchise Fees	53,598	53,800	53,610	53,800	53,787	53,800	(202)	(1)	(23)	222	(184)	(5)	(3)	(4)	-	
21 Utility Income Tax	93,414	93,513	93,513	93,513	93,414	93,513	(2,067)	(6)	(179)	6	(5)	(0)	(0)	(0)	-	
22 Total Operating Expenses & Taxes	1,735,951	1,736,311	1,736,067	1,736,311	1,736,194	1,736,311	(2,327)	(7)	(209)	8,667	(7,161)	(210)	(103)	(155)	-	
23 **Utility Operating Income**	390,480	398,038	390,865	398,038	397,645	398,038	(5,591)	(24)	(694)	23	(19)	(1)	(0)	(0)	-	
	390,480	398,038	390,865	398,038	397,645	398,038										
24 **Average Rate Base**																
25 Avg. Gross Plant	11,630,140	11,630,140	11,630,140	11,630,140	11,630,140	11,630,140		(350)	(10,172)				-			
26 Avg. Accum. Deprec. / Amort	(5,284,044)	(5,284,044)	(5,284,044)	(5,284,044)	(5,284,044)	(5,284,044)										
27 Avg. Accum. Def Tax	(681,954)	(681,954)	(681,954)	(681,954)	(681,954)	(681,954)										
28 Avg. Accum. Def ITC	-	-	-	-	-	-										
29 **Avg. Net Utility Plant**	5,664,142	5,664,142	5,664,142	5,664,142	5,664,142	5,664,142	-	(350)	(10,172)	-	-	-	-	-	-	
30 Misc. Deferred Debits	6,294	6,294	6,294	6,294	6,294	6,294										
31 Operating Materials & Fuel	67,724	67,724	67,724	67,724	67,724	67,724										
32 Misc. Deferred Credits	(73,887)	(73,887)	(73,887)	(73,887)	(73,887)	(73,887)										
33 Working Cash	67,537	73,210	73,200	73,210	67,547	73,210	(91)	(0)	(8)	337	(279)	(8)	(4)	(6)	-	
34 **Average Rate Base**	5,731,810	5,737,484	5,737,473	5,737,484	5,731,820	5,737,484	(91)	(350)	(10,180)	337	(279)	(8)	(4)	(6)	-	
35 **Rate of Return**	6.813%	6.938%	6.813%	6.938%	6.938%	6.938%		6.813%	6.813%	6.813%	6.812%	6.813%	6.813%	6.812%	#DIV/0!	
36 **Implied Return on Equity**	9.500%	9.500%	9.500%	9.500%	9.500%	9.500%		9.500%	9.500%	9.500%	9.500%	9.500%	9.500%	9.500%	#DIV/0!	
37 Effective Cost of Debt	4.125%	4.375%	4.125%	4.375%	4.375%	4.375%	4.125%	4.125%	4.125%	4.125%	4.125%	4.125%	4.125%	4.125%	4.125%	
38 Effective Cost of Preferred	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	
39 Debt Share of Cap Structure	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	
40 Preferred Share of Cap Structure	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	
41 Weighted Cost of Debt	2.063%	2.188%	2.063%	2.188%	2.188%	2.188%	2.063%	2.063%	2.063%	2.063%	2.063%	2.063%	2.063%	2.063%	2.063%	
42 Weighted Cost of Preferred	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	
43 Equity Share of Cap Structure	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	
44 State Tax Rate	7.594%	7.594%	7.594%	7.594%	7.594%	7.594%	7.594%	7.594%	7.594%	7.594%	7.594%	7.594%	7.594%	7.594%	7.594%	
45 Federal Tax Rate	21.000%	21.000%	21.000%	21.000%	21.000%	21.000%	21.000%	21.000%	21.000%	21.000%	21.000%	21.000%	21.000%	21.000%	21.000%	
46 Composite Tax Rate	27.000%	27.000%	27.000%	27.000%	27.000%	27.000%	27.000%	27.000%	27.000%	27.000%	27.000%	27.000%	27.000%	27.000%	27.000%	
47 Bad Debt Rate	0.3264%	0.3264%	0.326%	0.3264%	0.326%	0.3264%	0.326%	0.326%	0.326%	0.326%	0.326%	0.326%	0.326%	0.326%	0.326%	
48 Franchise Fee Rate	2.556%	2.556%	2.556%	2.556%	2.556%	2.556%	2.556%	2.556%	2.556%	2.556%	2.556%	2.556%	2.556%	2.556%	2.556%	
49 Working Cash Factor	3.891%	4.216%	4.216%	4.216%	3.891%	4.216%	3.891%	3.891%	3.891%	3.891%	3.891%	3.891%	3.891%	3.891%	3.891%	
50 Gross-Up Factor	1.370	1.370	1.370	1.370	1.370	1.370	1.370	1.370	1.370	1.370	1.370	1.370	1.370	1.370	1.370	
51 ROE Target	9.500%	9.500%	9.500%	9.500%	9.500%	9.500%	9.500%	9.500%	9.500%	9.500%	9.500%	9.500%	9.500%	9.500%	9.500%	
52 Grossed-Up COC	8.569%	8.694%	8.569%	8.694%	8.694%	8.694%	8.569%	8.569%	8.569%	8.569%	8.569%	8.569%	8.569%	8.569%	8.569%	
53 OPUC Fee Rate	0.4055%	0.4055%	0.4055%	0.4055%	0.4055%	0.4055%	0.4055%	0.4055%	0.4055%	0.4055%	0.4055%	0.4055%	0.4055%	0.4055%	0.4055%	
Utility Income Taxes																
54 Book Revenues	2,126,430	2,134,349	2,126,932	2,134,349	2,133,839	2,134,349	(7,918)	(31)	(902)	8,690	(7,180)	(211)	(104)	(156)	-	
55 Book Expenses	1,642,537	1,642,797	1,642,553	1,642,797	1,642,781	1,642,797	(260)	(1)	(30)	8,661	(7,156)	(210)	(103)	(155)	-	
56 Interest Deduction	118,219	125,507	118,335	125,507	125,384	125,507	(2)	(7)	(210)	7	(6)	(0)	(0)	(0)	-	
57 Production Deduction	-	-	-	-	-	-										
58 Permanent Ms	(14,248)	(14,248)	(14,248)	(14,248)	(14,248)	(14,248)										
59 Deferred Ms	154,217	154,217	154,217	154,217	154,217	154,217										
60 Taxable Income	225,706	226,075	226,074	226,075	225,707	226,075	(7,656)	(23)	(662)	22	(18)	(1)	(0)	(0)	-	
61 Current State Tax	17,141	17,169	17,169	17,169	17,141	17,169	(581)	(2)	(50)	2	(1)	(0)	(0)	(0)	-	
62 State Tax Credits	(10)	(10)	(10)	(10)	(10)	(10)										
63 Net State Taxes	17,131	17,159	17,159	17,159	17,131	17,159	(581)	(2)	(50)	2	(1)	(0)	(0)	(0)	-	
64 Federal Taxable Income	208,575	208,916	208,916	208,916	208,576	208,916	(7,075)	(21)	(612)	20	(17)	(0)	(0)	(0)	-	
65 Current Federal Tax	43,801	43,872	43,872	43,872	43,801	43,872	(1,486)	(4)	(129)	4	(4)	(0)	(0)	(0)	-	
66 Federal Tax Credits	-	-	-	-	-	-										
67 Excess ADIT Reversal (ARAM)	(9,156)	(9,156)	(9,156)	(9,156)	(9,156)	(9,156)										
68 Deferred Taxes	41,638	41,638	41,638	41,638	41,638	41,638	-	-	-	-	-	-	-	-	-	
69 Total Income Tax Expense	93,414	93,513	93,513	93,513	93,414	93,513	(2,067)	(6)	(179)	6	(5)	(0)	(0)	(0)	-	
73 Regulated Net Income	272,261	272,530	272,530	272,530	272,261	272,530	(5,589)	(17)	(484)	16	(13)	(0)	(0)	(0)	-	

Non-NVPC Adjustment Detail

		S-8, S-9, S-10 Bundled				S-22, A-20, A-23 Bundled				
		Memberships	CAISO Membership	Meals and Entertainment	Bundled Adjustment	Fuel Stock Adjustment	ADIT - Boardman Removal	Colstrip Smart Burn	Bundled Adjustment	**Total Non-NVPC Adjustments**
1	Sales to Consumers	-	-	-	(726)	-	-	-	(931)	(10,949)
2	Sales for Resale									-
3	Other Revenue									165
4	Total Operating Revenues	-	-	-	(726)	-	-	-	(931)	(10,784)
5	Net Variable Power Costs									-
6	Production O&M (Excludes Trojan)									-
7	Trojan O&M									-
8	Transmission O&M									-
9	Distribution O&M									(6,920)
10	Customer & MBC O&M									-
11	Uncollectibles Expense	-	-	-	(2)	-	-	-	(3)	(36)
12	OPUC Fees	-	-	-	(3)	-	-	-	(4)	(44)
13	A&G, Ins/Bene., & Gen. Plant	-	-	-	(700)					(1,153)
14	Total Operating & Maintenance	-	-	-	(705)	-	-	-	(7)	(8,153)
15	Depreciation	-								-
16	Amortization									-
17	Property Tax									-
18	Payroll Tax									-
19	Other Taxes									8,375
20	Franchise Fees	-	-	-	(19)	-	-	-	(24)	(280)
21	Utility Income Tax	-	-	-	(0)	-	-	-	(185)	(2,767)
22	Total Operating Expenses & Taxes	-	-	-	(724)	-	-	-	(215)	(2,825)
23	**Utility Operating Income**	-	-	-	(2)	-	-	-	(716)	(7,959)
24	**Average Rate Base**									
25	Avg. Gross Plant							-	(10,500)	(30,022)
26	Avg. Accum. Deprec. / Amort	-								-
27	Avg. Accum. Def Tax									(5,761)
28	Avg. Accum. Def ITC									-
29	**Avg. Net Utility Plant**	-	-	-	-	-	-	-	(10,500)	(35,783)
30	Misc. Deferred Debits									-
31	Operating Materials & Fuel					-				-
32	Misc. Deferred Credits									-
33	Working Cash	-	-	-	(28)	-	-	-	(8)	(110)
34	**Average Rate Base**	-	-	-	(28)	-	-	-	(10,508)	(35,893)
35	**Rate of Return**	#DIV/0!	#DIV/0!	#DIV/0!	6.812%	#DIV/0!	#DIV/0!	#DIV/0!	6.813%	22.174%
36	**Implied Return on Equity**	#DIV/0!	#DIV/0!	#DIV/0!	9.500%	#DIV/0!	#DIV/0!	#DIV/0!	9.500%	40.223%
37	Effective Cost of Debt	4.125%	4.125%	4.125%	4.125%	4.125%	4.125%	4.125%	4.125%	4.125%
38	Effective Cost of Preferred	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
39	Debt Share of Cap Structure	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%
40	Preferred Share of Cap Structure	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
41	Weighted Cost of Debt	2.063%	2.063%	2.063%	2.063%	2.063%	2.063%	2.063%	2.063%	2.063%
42	Weighted Cost of Preferred	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
43	Equity Share of Cap Structure	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%
44	State Tax Rate	7.594%	7.594%	7.594%	7.594%	7.594%	7.594%	7.594%	7.594%	7.594%
45	Federal Tax Rate	21.000%	21.000%	21.000%	21.000%	21.000%	21.000%	21.000%	21.000%	21.000%
46	Composite Tax Rate	27.000%	27.000%	27.000%	27.000%	27.000%	27.000%	27.000%	27.000%	27.000%
47	Bad Debt Rate	0.326%	0.326%	0.326%	0.326%	0.326%	0.326%	0.326%	0.326%	0.326%
48	Franchise Fee Rate	2.556%	2.556%	2.556%	2.556%	2.556%	2.556%	2.556%	2.556%	2.556%
49	Working Cash Factor	3.891%	3.891%	3.891%	3.891%	3.891%	3.891%	3.891%	3.891%	3.891%
50	Gross-Up Factor	1.370	1.370	1.370	1.370	1.370	1.370	1.370	1.370	1.370
51	ROE Target	9.500%	9.500%	9.500%	9.500%	9.500%	9.500%	9.500%	9.500%	9.500%
52	Grossed-Up COC	8.569%	8.569%	8.569%	8.569%	8.569%	8.569%	8.569%	8.569%	8.569%
53	OPUC Fee Rate	0.4055%	0.4055%	0.4055%	0.4055%	0.4055%	0.4055%	0.4055%	0.4055%	0.4055%
	Utility Income Taxes									
54	Book Revenues	-	-	-	(726)	-	-	-	(931)	(10,784)
55	Book Expenses	-	-	-	(724)	-	-	-	(31)	202
56	Interest Deduction	-	-	-	(1)	-	-	-	(217)	(738)
57	Production Deduction									-
58	Permanent Ms									-
59	Deferred Ms									-
60	Taxable Income	-	-	-	(2)	-	-	-	(684)	(10,248)
61	Current State Tax	-	-	-	(0)	-	-	-	(52)	(778)
62	State Tax Credits									-
63	Net State Taxes	-	-	-	(0)	-	-	-	(52)	(778)
64	Federal Taxable Income	-	-	-	(2)	-	-	-	(632)	(9,470)
65	Current Federal Tax	-	-	-	(0)	-	-	-	(133)	(1,989)
66	Federal Tax Credits									-
67	Excess ADIT Reversal (ARAM)									-
68	Deferred Taxes	-	-	-	-	-	-	-	-	-
69	Total Income Tax Expense	-	-	-	(0)	-	-	-	(185)	(2,767)
73	Regulated Net Income	-	-	-	(1)	-	-	-	(499)	(7,221)

NVPC Adjustment Detail

		7/15/2021 NVPC Update	8/31/2021 Stipulation	10/1/2021 NVPC Update	11/5/2021 NVPC Update	11/15/2021 NVPC Update	Blank	Total NVPC Adjustments
		(1)	(2)	(3)	(4)	(5)	(6)	
1	Sales to Consumers	1,628	(8,378)	13,903	26,075	209	-	33,437
2	Sales for Resale							-
3	Other Revenues							-
4	Total Operating Revenues	1,628	(8,378)	13,903	26,075	209	-	33,437
5	Net Variable Power Costs	1,569	(8,075)	13,400	25,131	201		32,227
6	Production O&M (Excludes Trojan)							-
7	Trojan O&M							-
8	Transmission O&M							-
9	Distribution O&M							-
10	Customer & MBC O&M							-
11	Uncollectibles Expense	5	(27)	45	85	1	-	109
12	OPUC Fees	7	(34)	56	106	1	-	136
13	A&G, Ins/Bene., & Gen. Plant							-
14	Total Operating & Maintenance	1,581	(8,136)	13,502	25,322	203	-	32,471
15	Depreciation							-
16	Amortization							-
17	Property Tax							-
18	Payroll Tax							-
19	Other Taxes							-
20	Franchise Fees	42	(214)	355	666	5	-	855
21	Utility Income Tax	1	(6)	9	18	0	-	23
22	Total Operating Expenses & Taxes	1,623	(8,356)	13,866	26,006	208	-	33,349
23	**Utility Operating Income**	4	(22)	37	69	1	-	88
24	**Average Rate Base**							
25	Avg. Gross Plant							-
26	Avg. Accum. Deprec. / Amort							-
27	Avg. Accum. Def Tax							-
28	Avg. Accum. Def ITC							-
29	**Avg. Net Utility Plant**	-	-	-	-	-	-	-
30	Misc. Deferred Debits							-
31	Operating Materials & Fuel							-
32	Misc. Deferred Credits							-
33	Working Cash	63	(325)	539	1,012	8	-	1,297
34	**Average Rate Base**	63	(325)	539	1,012	8	-	1,297
35	**Rate of Return**	6.813%						6.813%
36	**Implied Return on Equity**	9.500%						9.500%

37	Effective Cost of Debt	4.125%	4.125%	4.125%	4.125%	4.125%	4.125%	4.125%
38	Effective Cost of Preferred	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
39	Debt Share of Cap Structure	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%
40	Preferred Share of Cap Structure	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
41	Weighted Cost of Debt	2.063%	2.063%	2.063%	2.063%	2.063%	2.063%	2.063%
42	Weighted Cost of Preferred	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
43	Equity Share of Cap Structure	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%
44	State Tax Rate	7.594%	7.594%	7.594%	7.594%	7.594%	7.594%	7.594%
45	Federal Tax Rate	21.000%	21.000%	21.000%	21.000%	21.000%	21.000%	21.000%
46	Composite Tax Rate	27.000%	27.000%	27.000%	27.000%	27.000%	27.000%	27.000%
47	Bad Debt Rate	0.326%	0.326%	0.326%	0.326%	0.326%	0.326%	0.326%
48	Franchise Fee Rate	2.556%	2.556%	2.556%	2.556%	2.556%	2.556%	2.556%
49	Working Cash Factor	3.891%	3.891%	3.891%	3.891%	3.891%	3.891%	3.891%
50	Gross-Up Factor	1.370	1.370	1.370	1.370	1.370	1.370	1.370
51	ROE Target	9.500%	9.500%	9.500%	9.500%	9.500%	9.500%	9.500%
52	Grossed-Up COC	8.569%	8.569%	8.569%	8.569%	8.569%	8.569%	8.569%
53	OPUC Fee Rate	0.406%	0.406%	0.406%	0.406%	0.406%	0.406%	0.406%
	Utility Income Taxes							
54	Book Revenues	1,628	(8,378)	13,903	26,075	209	-	33,437
55	Book Expenses	1,622	(8,350)	13,857	25,989	208	-	33,326
56	Interest Deduction	1	(7)	11	21	0	-	27
57	Production Deduction							-
58	Permanent Ms							-
59	Deferred Ms							-
60	Taxable Income	4	(21)	35	66	1	-	84
61	Current State Tax	0	(2)	3	5	0	-	6
62	State Tax Credits							-
63	Net State Taxes	0	(2)	3	5	0	-	6
64	Federal Taxable Income	4	(20)	32	61	0	-	78
65	Current Federal Tax	1	(4)	7	13	0	-	16
66	Federal Tax Credits							-
67	ITC Amort							-
68	Deferred Taxes	-	-	-	-	-	-	-
69	Total Income Tax Expense	1	(6)	9	18	0	-	23
73	Regulated Net Income	3	(15)	26	48	0	-	62

Category A Advertising
Adjust Result to 1/8 of 1% per OAR

9090001 CustSvc-InformAdvertisingExp	2,035,889
Less: Legally Mandated Advertising	5,257
	2,030,632
2022 Total Revenue Requirement	2,127,491
Factor per OAR	0.125%
Presumed Reasonable Cat A Costs	2,659,364
Total Adjustment	-

Production Tax Credits (PTCs) in 2022 Net Variable Power Cost

Grossed Up for Taxes	(40,431)
Gross Up Factor	1.3696
PTCs	(29,519)

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 394

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for 2022 General Rate Revision	**PARTIAL STIPULATION**

This Third Partial Stipulation ("Stipulation") is between Portland General Electric Company ("PGE"), Staff of the Public Utility Commission of Oregon ("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"), Walmart, Inc. ("Walmart"), and Small Business Utility Advocate ("SBUA"), (collectively, the ("Stipulating Parties"). Calpine Solutions ("Calpine") did not take a position on the issues resolved by this Stipulation, therefore is not a party to this Stipulation but does not oppose it.

PGE previously filed a First Partial Stipulation in this docket resolving all issues related to Cost of Capital in this general rate case. PGE then filed a Second Partial Stipulation after reaching an agreement with the parties on certain matters at settlement discussions on November 5, 2021. SBUA was not a party to the First or Second Partial Stipulations previously filed. The Stipulating Parties participated in a third round of settlement discussions beginning on December 7, 2021, and no other parties participated in the discussion. As a result of the discussions, the Stipulating Parties have reached a compromise settlement resolving several additional issues in this docket, as set forth below.

TERMS OF THIRD PARTIAL STIPULATION

1. This Stipulation resolves only the general rate case issues described below.

2. Bundled Issues (Bundled Issues): S-05, S-07, S-11, S-13, S-14, S-15, S-16, S-17, S-20, S-23, S-25, S-26, A-08, A-09, A-10, A-12, A-14, A-15, A-16, A-17, A-19, A-21, A-22, A-27, A-28, C-3, and C-10. Please see Table 1, below, for an expanded itemization of issues contained herein.

   a. Parties agree to settle all remaining revenue requirement issues for a $10 million increase in non-net variable power costs, with two exceptions.

      i. First, the $3 million hold-back proposed by Staff within its wildfire mitigation and vegetation management mechanism would continue to be litigated as a part of the mechanism. If Staff prevails, the revenue requirement increase resulting from this stipulation will be $7 million. If the Commission determines an amount other than $3 million should be "held back," the revenue requirement increase associated with this stipulation will be $10 million minus the amount held back.

      ii. Second, issues regarding the appropriate limitations on fee free bank card usage by small commercial customers will continue to be litigated.

      iii. Third, AWEC's issue A-25 Related to the funding of the Trojan Nuclear Decommissioning Trusts will continue to be litigated.

   b. This Bundled Issues settlement does not constitute an agreement that PGE is allowed to recover the expenses associated with Amazon Pay in excess of the per-transaction costs associated with other digital wallet payment options.

   c. The $10 million does not include the Oregon Corporate Activities Tax of $8.4 million, which has been moved from a supplemental schedule to base rates.

Table 1
Revenue Requirement Items in Bundled Issues

Issue No.	Topic
S-05	Incentive Related Payroll Taxes
S-07	Wages and Salaries, FTEs, Incentives
S-11	Other Revenues
S-13	Line Extension Allowances
S-14	Approved TE programs
S-15	Unapproved TE programs
S-16	Non-Labor A&G
S-17	IT Projects
S-20	Pension and Post-Retirement Medical
S-23	Transmission & Distribution Capital
S-25	Customer Service Non-Labor O&M
S-26	ADMS and Distribution Capital
A-08	Revolver Fees
A-09	Margin Net Interest
A-10	Property Insurance
A-12	Plant Capital Update
A-14	Joint Pole Plant Construction
A-15	Compensation
A-16	O&M Escalations
A-17	AFUDC Equity
A-19	ADIT Storm Collection
A-21	ADIT PTCs
A-22	Schedule 146 Colstrip Reserves
A-27	OATT Revenues
A-28	WTC Lease
C-3	Mass Transit Benefit
C-10	Amazon Pay

3. Faraday, (S-21, A-13)

a. PGE will remove Faraday from the revenue requirement for the May 9 price effective date. PGE is free to argue in this rate case or a subsequent proceeding that PGE should be allowed to recover capital and other costs associated with Faraday in a tariff rider approved by the Commission in this case or a future single-issue ratemaking proceeding. Staff and intervenors are free to oppose any request for a tariff rider or single-issue rate proceeding and may argue that rate recovery for Faraday must be determined in a future general rate case.

4. Parties agree the Bundled Issues settlement does not constitute an agreement between the parties that all capital investments in this proceeding are either prudent or imprudent. A Party is free to argue in future proceedings that the Commission should order PGE to remove from its rate base a specific plant investment that was contested by such party and not specifically addressed by the first two stipulations in this rate proceeding. Until rates are ordered in a subsequent general rate proceeding, for earnings review purposes, the Company agrees to remove $15 million of plant investment beginning with the effective date of tariffs from this proceeding.

5. Residential Customer Deposits, (C-01)

   a. PGE agrees to permanently cease the collection of residential customer deposits beginning on the rate effective date of this general rate case.

6. Load Forecasting

   a. Parties agree that this settlement resolves all issues related to load forecasting. The load forecast to be used in this case will match the final load forecast included in PGE's November 15th MONET update filing for power costs.

7. Decoupling

   a. PGE agrees that accruals related to the decoupling mechanism under Schedule 123 will terminate (i.e., both the SNA and LRRA) on May 9th with the rate effective date of this case. Any amounts identified under the current mechanism up to that date would still be subject to future amortization in Schedule 123.

8. Future Rate Case Process

   a. PGE agrees to work constructively with OPUC Staff on the responses to Standard Data Request Nos. 57 and 58.

   b. PGE also agrees to work constructively with OPUC Staff to provide additional visibility into PGE's capital budgeting and execution process.

9. The Stipulating Parties agree that the following items are not resolved by this Stipulation and will continue to be litigated:

   a. Wildfire Emergency, Ice Storm and Boardman Deferrals

   b. Wildfire mitigation and vegetation management mechanism

   c. Level III outage mechanism

   d. Faraday rider or single-issue proceeding

   e. Fee free bank card for small commercial customers – both customer limitations and rate spread

   f. Rate spread and rate design generally

   g. Non-bypassibility of schedules 135, 137, and 150

   h. Schedule 90 sub-transmission rate

   i. Habitat restoration proposal

   j. PGE's residential line extension allowance amounts

   k. PGE's temporary service proposal

   l. Trojan Nuclear Decommissioning Trust (NDT) Contributions (AWEC Issue A-25)

10. Stipulating Parties recommend and request that the Commission approve the adjustments and provisions described herein as appropriate and reasonable resolutions of all issues addressed in this Stipulation.

11. Stipulating Parties agree that this Stipulation is in the public interest, and will result in rates that are fair, just, and reasonable, consistent with the standard in ORS 756.040.

12. Stipulating Parties agree that this Stipulation represents a compromise in the positions of the Stipulating Parties. Without the written consent of all the Stipulating Parties, evidence of conduct or statements, including but not limited to term sheets or other documents created solely for use in settlement conferences in this docket, are confidential and not admissible in this instance or any subsequent proceeding, unless independently discoverable or offered for other purposes allowed under ORS 40.190.

13. Stipulating Parties have negotiated this Stipulation as an integrated document. The Stipulating Parties seek to obtain Commission approval of this Stipulation after initial briefs are filed but prior to evidentiary hearings. If the Commission rejects all or any material part of this Stipulation, or adds any material condition to any final order that is not consistent with this Stipulation, each Stipulating Party reserves its right: (i) pursuant to OAR 860-001-0350(9), to present evidence and argument on the record in support of the Stipulation, including the right to cross-examine witnesses, introduce evidence as deemed appropriate to respond fully to issues presented, and raise issues that are incorporated in the settlements embodied in this Stipulation; and (ii) pursuant to ORS 756.561 and OAR 860-001-0720, to seek rehearing or reconsideration, or pursuant to ORS 756.610 to appeal the Commission's final order. Stipulating Parties agree that in the event the Commission rejects all or any material part of this Stipulation or adds any material condition to any final order that is not consistent with this Stipulation, Stipulating Parties will meet in good faith within ten days and discuss next steps. A Stipulating Party may withdraw from the

Stipulation after this meeting by providing written notice to the Commission and other Stipulating Parties.

14. This Stipulation will be offered into the record in this proceeding as evidence pursuant to OAR 860-001-0350(7). Stipulating Parties agree to support this Stipulation throughout this proceeding and in any appeal and provide witnesses to support this Stipulation (if required by the Commission), and recommend that the Commission issue an order adopting the settlement contained herein. By entering into this Stipulation, no Stipulating Party shall be deemed to have approved, admitted or consented to the facts, principles, methods or theories employed by any other Stipulating Party in arriving at the terms of this Stipulation. Except as provided in this Stipulation, no Stipulating Party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding.

15. This Stipulation may be signed in any number of counterparts, each of which will be an original for all purposes, but all of which taken together will constitute one and the same agreement.

DATED this 13th day of January 2022.

Loretta Mabinton

PORTLAND GENERAL ELECTRIC COMPANY

Jill Goatcher

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

OREGON CITIZENS' UTILITY BOARD

ALLIANCE OF WESTERN ENERGY CONSUMERS

THE KROGER CO.

WALMART INC.

SMALL BUSINESS UTILITY ADVOCATE

PORTLAND GENERAL ELECTRIC COMPANY

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

OREGON CITIZENS' UTILITY BOARD

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PORTLAND GENERAL ELECTRIC
COMPANY

STAFF OF THE PUBLIC UTILITY
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Corinne Milinovich

ALLIANCE OF WESTERN
ENERGY CONSUMERS

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THE KROGER CO.

WALMART INC.

Diane Henkels

SMALL BUSINESS UTILITY ADVOCATE

Portland General Electric Company
2022 Revenue Requirement Summary
($000)

	Revenue	Percent
Total Increase:	82,830	4.09%

	Base Business 2022	Blank	Total Results	Check			
	(1)	(2)	(3)				
1 Sales to Consumers	2,106,801	-	2,106,801	2,106,801	2,106,801	TRUE	OK
2 Sales for Resale	-		-		-	TRUE	OK
3 Other Revenues	29,511		29,511		29,511	TRUE	OK
4 Total Operating Revenues	2,136,311	-	2,136,311		2,136,311	TRUE	OK
5 Net Variable Power Costs	543,993		543,993		543,993	TRUE	OK
6 Production O&M (excludes Trojan)	126,068		126,068		126,068	TRUE	OK
7 Trojan O&M	93		93		93	TRUE	OK
8 Transmission O&M	19,874		19,874		19,874	TRUE	OK
9 Distribution O&M	145,849		145,849		145,849	TRUE	OK
10 Customer & MBC O&M	83,085		83,085		83,085	TRUE	OK
11 Uncollectibles Expense	6,876	-	6,876	0.3264%	6,876	TRUE	OK
12 OPUC Fees	8,544	-	8,544	0.4055%	8,544	TRUE	OK
13 A&G, Ins/Bene., & Gen. Plant	174,876		174,876		174,876	TRUE	OK
14 Total Operating & Maintenance	1,109,257	-	1,109,257		1,109,257	TRUE	OK
15 Depreciation	334,013		334,013		334,013	TRUE	OK
16 Amortization	59,713		59,713		59,713	TRUE	OK
17 Property Tax	82,106		82,106		82,106	TRUE	OK
18 Payroll Tax	16,503		16,503		16,503	TRUE	OK
19 Other Taxes	11,310		11,310		11,310	TRUE	OK
20 Franchise Fees	53,846	-	53,846	2.5558%	53,846	TRUE	OK
21 Utility Income Tax	90,851	-	90,851		90,851	TRUE	OK
22 Total Operating Expenses & Taxes	1,757,598	-	1,757,598		1,757,598	TRUE	OK
23 **Utility Operating Income**	378,713	-	378,713	378,713	378,713	TRUE	OK
24 **Rate Base**							

	Base Business 2022	Blank	Total Results		Check		
	(1)	(2)	(3)				
25 Avg. Gross Plant	11,465,733		11,465,733		11,465,733	TRUE	OK
26 Avg. Accum. Deprec. / Amort	(5,279,126)		(5,279,126)		(5,279,126)	TRUE	OK
27 Avg. Accum. Def Tax	(696,026)		(696,026)		(696,026)	TRUE	OK
28 Avg. Accum. Def ITC	-		-		-	TRUE	OK
29 **Net Utility Plant**	5,490,581	-	5,490,581		5,490,581	TRUE	OK
30 Misc. Deferred Debits	6,294		6,294		6,294	TRUE	OK
31 Operating Materials & Fuel	67,724		67,724		67,724	TRUE	OK
32 Misc. Deferred Credits	(73,887)		(73,887)		(73,887)	TRUE	OK
33 Working Cash	68,379	-	68,379	3.8905%	68,379	TRUE	OK
34 **Rate Base**	5,559,092	-	5,559,092		5,559,092	TRUE	OK
35 **Rate of Return**	6.813%		6.813%		6.813%		
36 **Implied Return on Equity**	9.500%		9.500%		9.500%		

	Base Business 2022	Blank	Total Results	Check		
	(1)	(2)	(3)			
37 Effective Cost of Debt	4.125%	4.125%	4.125%	4.1250%	TRUE	
38 Effective Cost of Preferred	0.000%	0.000%	0.000%	0.0000%	TRUE	
39 Debt Share of Cap Structure	50.000%	50.000%	50.000%	50.0000%	TRUE	
40 Preferred Share of Cap Structure	0.000%	0.000%	0.000%	0.0000%	TRUE	
41 Weighted Cost of Debt	2.063%	2.063%	2.063%	2.0625%	TRUE	
42 Weighted Cost of Preferred	0.000%	0.000%	0.000%	0.0000%	TRUE	
43 Equity Share of Cap Structure	50.000%	50.000%	50.000%	50.0000%	TRUE	
44 State Tax Rate	7.594%	7.594%	7.594%	7.5943%	TRUE	
45 Federal Tax Rate	21.000%	21.000%	21.000%	21.0000%	TRUE	
46 Composite Tax Rate	27.000%	27.000%	27.000%	26.9995%	TRUE	
47 Bad Debt Rate	0.326%	0.326%	0.326%	0.3264%	TRUE	
48 Franchise Fee Rate	2.556%	2.556%	2.556%	2.5558%	TRUE	
49 Working Cash Factor	3.891%	3.891%	3.891%	3.8905%	TRUE	
50 Gross-Up Factor	1.370	1.370	1.370	136.9854%	TRUE	
51 ROE Target	9.500%	9.500%	9.500%	9.5000%	TRUE	
52 Grossed-Up COC	8.569%	8.569%	8.569%	8.5693%	TRUE	
53 OPUC Fee Rate	0.4055%	0.406%	0.406%	0.4055%	TRUE	
Utility Income Taxes						
54 Book Revenues	2,136,311	-	2,136,311	2,136,311	TRUE	OK
55 Book Expenses	1,666,747	-	1,666,747	1,666,747	TRUE	OK
56 Interest Deduction	114,656	-	114,656	114,656	TRUE	OK
57 Production Deduction	-		-	-	TRUE	OK
58 Permanent Ms	(15,524)		(15,524)	(15,524)	TRUE	OK
59 Deferred Ms	139,481		139,481	139,481	TRUE	OK
60 Taxable Income	230,951	-	230,951	230,951	TRUE	OK
61 Current State Tax	17,539	-	17,539	17,539	TRUE	OK
62 State Tax Credits	(10)		(10)	(10)	TRUE	OK
63 Net State Taxes	17,529	-	17,529	17,529	TRUE	OK
64 Federal Taxable Income	213,422	-	213,422	213,422	TRUE	OK
65 Current Federal Tax	44,819	-	44,819	44,819	TRUE	OK

	Base Business 2022	Blank	Total Results	Check		
	(1)	(2)	(3)			
66 Federal Tax Credits	-		-	-	TRUE	OK
67 Excess ADIT Reversal (ARAM)	(9,156)		(9,156)	(9,156)	TRUE	OK
68 Deferred Taxes	37,659	-	37,659	37,659	TRUE	OK
69 Total Income Tax Expense	90,851	-	90,851	90,851	TRUE	OK
70 Regulated Net Income	264,057		264,057			
71 Check Regulated NI			264,057			

Portland General Electric Company
2022 Revenue Requirement - Base Business
($000)

	Revenue	Percent
Total Increase:	82,830	4.09%

	At Current Rates	Sept. Load Forecast Delta	GRC Change for RROE	Proposed 2022	Non-NVPC Adjustments	NVPC Adjustments	Total Results		Check		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)				
1 Sales to Consumers	2,006,036	17,935	81,032	2,105,003	(31,639)	33,437	2,106,801		2,106,801	TRUE	OK
2 Sales for Resale	-			-	-	-	-		-	TRUE	OK
3 Other Revenues	29,346			29,346	165	-	29,511		29,511	TRUE	OK
4 Total Operating Revenues	2,035,381		81,032	2,134,349	(31,474)	33,437	2,136,311		2,136,311	TRUE	OK
5 Net Variable Power Costs	511,766			511,766	-	32,227	543,993		543,993	TRUE	OK
6 Production O&M (excludes Trojan)	126,068			126,068	-	-	126,068		126,068	TRUE	OK
7 Trojan O&M	93			93	-	-	93		93	TRUE	OK
8 Transmission O&M	19,874			19,874	-	-	19,874		19,874	TRUE	OK
9 Distribution O&M	152,769			152,769	(6,920)	-	145,849		145,849	TRUE	OK
10 Customer & MBC O&M	83,085			83,085	-	-	83,085		83,085	TRUE	OK
11 Uncollectibles Expense	6,547		323	6,870	(103)	109	6,876	0.3264%	6,876	TRUE	OK
12 OPUC Fees	8,135		401	8,537	(128)	136	8,544	0.4055%	8,544	TRUE	OK
13 A&G, Ins/Bene., & Gen. Plant	178,231			178,231	(3,355)	-	174,876		174,876	TRUE	OK
14 Total Operating & Maintenance	1,086,568		724	1,087,292	(10,507)	32,471	1,109,257		1,109,257	TRUE	OK
15 Depreciation	338,741			338,741	(4,728)	-	334,013		334,013	TRUE	OK
16 Amortization	59,713			59,713	-	-	59,713		59,713	TRUE	OK
17 Property Tax	83,814			83,814	(1,708)	-	82,106		82,106	TRUE	OK
18 Payroll Tax	16,503			16,503	-	-	16,503		16,503	TRUE	OK
19 Other Taxes	2,935			2,935	8,375	-	11,310		11,310	TRUE	OK
20 Franchise Fees	51,271		2,529	53,800	(809)	855	53,846	2.5558%	53,846	TRUE	OK
21 Utility Income Tax	67,679		25,835	93,513	(4,652)	23	90,851		90,851	TRUE	OK
22 Total Operating Expenses & Taxes	1,707,222		29,089	1,736,311	(14,029)	33,349	1,757,598		1,757,598	TRUE	OK
23 **Utility Operating Income**	328,159		69,878	398,038	(17,446)	88	378,713	378,713	378,713	TRUE	OK
				398,038			378,713				
24 **Average Rate Base**											
25 Avg. Gross Plant	11,630,140			11,630,140	(164,407)	-	11,465,733		11,465,733	TRUE	OK
26 Avg. Accum. Deprec. / Amort	(5,284,044)			(5,284,044)	4,918	-	(5,279,126)		(5,279,126)	TRUE	OK
27 Avg. Accum. Def Tax	(681,954)			(681,954)	(14,072)	-	(696,026)		(696,026)	TRUE	OK
28 Avg. Accum. Def ITC	-			-	-	-	-		-	TRUE	OK
29 **Avg. Net Utility Plant**	5,664,142		-	5,664,142	(173,561)	-	5,490,581		5,490,581	TRUE	OK
30 Misc. Deferred Debits	6,294			6,294	-	-	6,294		6,294	TRUE	OK
31 Operating Materials & Fuel	67,724			67,724	-	-	67,724		67,724	TRUE	OK
32 Misc. Deferred Credits	(73,887)			(73,887)	-	-	(73,887)		(73,887)	TRUE	OK
33 Working Cash	71,984		1,227	73,210	(546)	1,297	68,379	3.8905%	68,379	TRUE	OK
34 **Average Rate Base**	5,736,257		1,227	5,737,484	(174,107)	1,297	5,559,092		5,559,092	TRUE	OK
35 **Rate of Return**	5.721%			6.938%		6.813%	6.813%		6.813%		
36 **Implied Return on Equity**	7.067%			9.500%		9.500%	9.500%		9.500%		

37 Effective Cost of Debt	4.375%	4.375%	4.375%	4.125%	4.125%	4.125%	4.125%	TRUE	
38 Effective Cost of Preferred	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	TRUE	
39 Debt Share of Cap Structure	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	TRUE	
40 Preferred Share of Cap Structure	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	TRUE	
41 Weighted Cost of Debt	2.188%	2.188%	2.188%	2.063%	2.063%	2.063%	2.063%	TRUE	
42 Weighted Cost of Preferred	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	TRUE	
43 Equity Share of Cap Structure	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	TRUE	
44 State Tax Rate	7.594%	7.594%	7.594%	7.594%	7.594%	7.594%	7.594%	TRUE	
45 Federal Tax Rate	21.000%	21.000%	21.000%	21.000%	21.000%	21.000%	21.000%	TRUE	
46 Composite Tax Rate	27.000%	27.000%	27.000%	27.000%	27.000%	27.000%	27.000%	TRUE	
47 Bad Debt Rate	0.326%	0.326%	0.326%	0.326%	0.326%	0.326%	0.326%	TRUE	
48 Franchise Fee Rate	2.556%	2.556%	2.556%	2.556%	2.556%	2.556%	2.556%	TRUE	
49 Working Cash Factor	4.216%	4.216%	4.216%	3.891%	3.891%	3.891%	3.891%	TRUE	
50 Gross-Up Factor	1.370	1.370	1.370	1.370	1.370	1.370	1.370	TRUE	
51 ROE Target	9.500%	9.500%	9.500%	9.500%	9.500%	9.500%	9.500%	TRUE	
52 Grossed-Up COC	8.694%	8.694%	8.694%	8.569%	8.569%	8.569%	8.569%	TRUE	
53 OPUC Fee Rate	0.406%	0.406%	0.406%	0.406%	0.406%	0.406%	0.406%	TRUE	
Utility Income Taxes									
54 Book Revenues	2,035,381	98,967	2,134,349	(31,474)	33,437	2,136,311	2,136,311	TRUE	OK
55 Book Expenses	1,639,544	3,254	1,642,797	(9,376)	33,326	1,666,747	1,666,747	TRUE	OK
56 Interest Deduction	125,481	27	125,507	(3,591)	27	114,656	114,656	TRUE	OK
57 Production Deduction	-		-	-		-	-	TRUE	OK
58 Permanent Ms	(14,248)		(14,248)	(1,276)		(15,524)	(15,524)	TRUE	OK
59 Deferred Ms	154,217		154,217	(14,736)		139,481	139,481	TRUE	OK
60 Taxable Income	130,389	95,687	226,075	(2,496)	84	230,951	230,951	TRUE	OK
61 Current State Tax	9,902	7,267	17,169	(190)	6	17,539	17,539	TRUE	OK
62 State Tax Credits	(10)		(10)	-		(10)	(10)	TRUE	OK
63 Net State Taxes	9,892	7,267	17,159	(190)	6	17,529	17,529	TRUE	OK
64 Federal Taxable Income	120,496	88,420	208,916	(2,306)	78	213,422	213,422	TRUE	OK
65 Current Federal Tax	25,304	18,568	43,872	(484)	16	44,819	44,819	TRUE	OK
66 Federal Tax Credits	-		-	-		-	-	TRUE	OK
67 Excess ADIT Reversal (ARAM)	(9,156)	-	(9,156)	-		(9,156)	(9,156)	TRUE	OK
68 Deferred Taxes	41,638	0	41,638	(3,979)	-	37,659	37,659	TRUE	OK
69 Total Income Tax Expense	67,679	25,835	93,513	(4,652)	23	90,851	90,851	TRUE	OK
70 Regulated Net Income	202,679		272,530			264,057			
71 Check Regulated NI			272,530			264,057			

Non-NVPC Adjustment Detail

	All RevReq Sensitives	ROE	Cost of Debt	Comp Tax Rate	Working Cash	Revenue Sensitives	Total RevReq Sensitives
		9/30/21 Stipulation			12/2/21 Stipulation		
		S-1			S-18		
	(7,918)	-	(7,417)	-	(509)	-	
1 Sales to Consumers	2,097,085	2,105,003	2,097,586	2,105,003	2,104,494	2,105,003	(7,918)
2 Sales for Resale	-	-	-	-	-	-	
3 Other Revenue	29,346	29,346	29,346	29,346	29,346	29,346	
4 Total Operating Revenues	2,126,430	2,134,349	2,126,932	2,134,349	2,133,839	2,134,349	(7,918)
5 Net Variable Power Costs	511,766	511,766	511,766	511,766	511,766	511,766	
6 Production O&M (Excludes Trojan)	126,068	126,068	126,068	126,068	126,068	126,068	
7 Trojan O&M	93	93	93	93	93	93	
8 Transmission O&M	19,874	19,874	19,874	19,874	19,874	19,874	
9 Distribution O&M	152,769	152,769	152,769	152,769	152,769	152,769	
10 Customer & MBC O&M	83,085	83,085	83,085	83,085	83,085	83,085	
11 Uncollectibles Expense	6,844	6,870	6,845	6,870	6,868	6,870	(26)
12 OPUC Fees	8,505	8,537	8,507	8,537	8,535	8,537	(32)
13 A&G, Ins/Bene., & Gen. Plant	178,231	178,231	178,231	178,231	178,231	178,231	
14 Total Operating & Maintenance	1,087,234	1,087,292	1,087,238	1,087,292	1,087,288	1,087,292	(58)
15 Depreciation	338,741	338,741	338,741	338,741	338,741	338,741	
16 Amortization	59,713	59,713	59,713	59,713	59,713	59,713	
17 Property Tax	83,814	83,814	83,814	83,814	83,814	83,814	
18 Payroll Tax	16,503	16,503	16,503	16,503	16,503	16,503	
19 Other Taxes	2,935	2,935	2,935	2,935	2,935	2,935	
20 Franchise Fees	53,598	53,800	53,610	53,800	53,787	53,800	(202)
21 Utility Income Tax	93,414	93,513	93,513	93,513	93,414	93,513	(2,067)
22 Total Operating Expenses & Taxes	1,735,951	1,736,311	1,736,067	1,736,311	1,736,194	1,736,311	(2,327)
23 **Utility Operating Income**	390,480	398,038	390,865	398,038	397,645	398,038	(5,591)
	390,480	398,038	390,865	398,038	397,645	398,038	
24 **Average Rate Base**							
25 Avg. Gross Plant	11,630,140	11,630,140	11,630,140	11,630,140	11,630,140	11,630,140	
26 Avg. Accum. Deprec. / Amort	(5,284,044)	(5,284,044)	(5,284,044)	(5,284,044)	(5,284,044)	(5,284,044)	
27 Avg. Accum. Def Tax	(681,954)	(681,954)	(681,954)	(681,954)	(681,954)	(681,954)	
28 Avg. Accum. Def ITC	-	-	-	-	-	-	
29 **Avg. Net Utility Plant**	5,664,142	5,664,142	5,664,142	5,664,142	5,664,142	5,664,142	-
30 Misc. Deferred Debits	6,294	6,294	6,294	6,294	6,294	6,294	
31 Operating Materials & Fuel	67,724	67,724	67,724	67,724	67,724	67,724	
32 Misc. Deferred Credits	(73,887)	(73,887)	(73,887)	(73,887)	(73,887)	(73,887)	
33 Working Cash	67,537	73,210	73,200	73,210	67,547	73,210	(91)
34 **Average Rate Base**	5,731,810	5,737,484	5,737,473	5,737,484	5,731,820	5,737,484	(91)
35 **Rate of Return**	6.813%	6.938%	6.813%	6.938%	6.938%	6.938%	
36 **Implied Return on Equity**	9.500%	9.500%	9.500%	9.500%	9.500%	9.500%	
37 Effective Cost of Debt	4.125%	4.375%	4.125%	4.375%	4.375%	4.375%	4.125%
38 Effective Cost of Preferred	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
39 Debt Share of Cap Structure	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%
40 Preferred Share of Cap Structure	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
41 Weighted Cost of Debt	2.063%	2.188%	2.063%	2.188%	2.188%	2.188%	2.063%
42 Weighted Cost of Preferred	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
43 Equity Share of Cap Structure	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%
44 State Tax Rate	7.594%	7.594%	7.594%	7.594%	7.594%	7.594%	7.594%
45 Federal Tax Rate	21.000%	21.000%	21.000%	21.000%	21.000%	21.000%	21.000%
46 Composite Tax Rate	27.000%	27.000%	27.000%	27.000%	27.000%	27.000%	27.000%
47 Bad Debt Rate	0.3264%	0.3264%	0.326%	0.326%	0.3264%	0.3264%	0.326%
48 Franchise Fee Rate	2.556%	2.556%	2.556%	2.556%	2.556%	2.556%	2.556%
49 Working Cash Factor	3.891%	4.216%	4.216%	4.216%	3.891%	4.216%	3.891%
50 Gross-Up Factor	1.370	1.370	1.370	1.370	1.370	1.370	1.370
51 ROE Target	9.500%	9.500%	9.500%	9.500%	9.500%	9.500%	9.500%
52 Grossed-Up COC	8.569%	8.694%	8.569%	8.694%	8.694%	8.694%	8.569%
53 OPUC Fee Rate	0.4055%	0.4055%	0.4055%	0.4055%	0.4055%	0.4055%	0.4055%
Utility Income Taxes							
54 Book Revenues	2,126,430	2,134,349	2,126,932	2,134,349	2,133,839	2,134,349	(7,918)
55 Book Expenses	1,642,537	1,642,797	1,642,553	1,642,797	1,642,781	1,642,797	(260)
56 Interest Deduction	118,219	125,507	118,335	125,507	125,384	125,507	(2)
57 Production Deduction	-	-	-	-	-	-	
58 Permanent Ms	(14,248)	(14,248)	(14,248)	(14,248)	(14,248)	(14,248)	
59 Deferred Ms	154,217	154,217	154,217	154,217	154,217	154,217	
60 Taxable Income	225,706	226,075	226,074	226,075	225,707	226,075	(7,656)
61 Current State Tax	17,141	17,169	17,169	17,169	17,141	17,169	(581)
62 State Tax Credits	(10)	(10)	(10)	(10)	(10)	(10)	
63 Net State Taxes	17,131	17,159	17,159	17,159	17,131	17,159	(581)
64 Federal Taxable Income	208,575	208,916	208,916	208,916	208,576	208,916	(7,075)
65 Current Federal Tax	43,801	43,872	43,872	43,872	43,801	43,872	(1,486)
66 Federal Tax Credits	-	-	-	-	-	-	
67 Excess ADIT Reversal (ARAM)	(9,156)	(9,156)	(9,156)	(9,156)	(9,156)	(9,156)	
68 Deferred Taxes	41,638	41,638	41,638	41,638	41,638	41,638	-
69 Total Income Tax Expense	93,414	93,513	93,513	93,513	93,414	93,513	(2,067)
73 Regulated Net Income	272,261	272,530	272,530	272,530	272,261	272,530	(5,589)

	Excitation System	Beaver Modernization	OCAT	Level III Accrual	Directors' Def Compensation	D&O Ins	Directors' Expenses	R&D	ADIT-Incentive
	S-3	S-4	S-6	S-12 / A-24 / C-8	A-5	A-6	A-7	A-11	A-18
1 Sales to Consumers	(31)	(902)	8,690	(7,180)	(211)	(104)	(156)	-	(51
2 Sales for Resale									
3 Other Revenue									
4 Total Operating Revenues	(31)	(902)	8,690	(7,180)	(211)	(104)	(156)	-	(51
5 Net Variable Power Costs									
6 Production O&M (Excludes Trojan)									
7 Trojan O&M									
8 Transmission O&M									
9 Distribution O&M				(6,920)					
10 Customer & MBC O&M									
11 Uncollectibles Expense	(0)	(3)	28	(23)	(1)	(0)	(1)	-	(
12 OPUC Fees	(0)	(4)	35	(29)	(1)	(0)	(1)	-	(
13 A&G, Ins/Bene., & Gen. Plant					(203)	(100)	(150)	-	-
14 Total Operating & Maintenance	(0)	(7)	64	(6,973)	(205)	(101)	(151)	-	(
15 Depreciation						-			
16 Amortization									
17 Property Tax									
18 Payroll Tax									
19 Other Taxes			8,375						
20 Franchise Fees	(1)	(23)	222	(184)	(5)	(3)	(4)	-	(1
21 Utility Income Tax	(6)	(179)	6	(5)	(0)	(0)	(0)	-	(10
22 Total Operating Expenses & Taxes	(7)	(209)	8,667	(7,161)	(210)	(103)	(155)	-	(11
23 **Utility Operating Income**	(24)	(694)	23	(19)	(1)	(0)	(0)	-	(39
24 **Average Rate Base**									
25 Avg. Gross Plant	(350)	(10,172)				-			
26 Avg. Accum. Deprec. / Amort									
27 Avg. Accum. Def Tax									(5,76
28 Avg. Accum. Def ITC									
29 **Avg. Net Utility Plant**	(350)	(10,172)	-	-	-	-	-	-	(5,76
30 Misc. Deferred Debits									
31 Operating Materials & Fuel									
32 Misc. Deferred Credits									
33 Working Cash	(0)	(8)	337	(279)	(8)	(4)	(6)	-	(
34 **Average Rate Base**	(350)	(10,180)	337	(279)	(8)	(4)	(6)	-	(5,76
35 **Rate of Return**	6.813%	6.813%	6.813%	6.812%	6.813%	6.813%	6.812%	#DIV/0!	6.813
36 **Implied Return on Equity**	9.500%	9.500%	9.500%	9.500%	9.500%	9.500%	9.500%	#DIV/0!	9.500
37 Effective Cost of Debt	4.125%	4.125%	4.125%	4.125%	4.125%	4.125%	4.125%	4.125%	4.125
38 Effective Cost of Preferred	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000
39 Debt Share of Cap Structure	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000
40 Preferred Share of Cap Structure	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000
41 Weighted Cost of Debt	2.063%	2.063%	2.063%	2.063%	2.063%	2.063%	2.063%	2.063%	2.063
42 Weighted Cost of Preferred	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000
43 Equity Share of Cap Structure	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000
44 State Tax Rate	7.594%	7.594%	7.594%	7.594%	7.594%	7.594%	7.594%	7.594%	7.594
45 Federal Tax Rate	21.000%	21.000%	21.000%	21.000%	21.000%	21.000%	21.000%	21.000%	21.000
46 Composite Tax Rate	27.000%	27.000%	27.000%	27.000%	27.000%	27.000%	27.000%	27.000%	27.000
47 Bad Debt Rate	0.326%	0.326%	0.326%	0.326%	0.326%	0.326%	0.326%	0.326%	0.326
48 Franchise Fee Rate	2.556%	2.556%	2.556%	2.556%	2.556%	2.556%	2.556%	2.556%	2.556
49 Working Cash Factor	3.891%	3.891%	3.891%	3.891%	3.891%	3.891%	3.891%	3.891%	3.891
50 Gross-Up Factor	1.370	1.370	1.370	1.370	1.370	1.370	1.370	1.370	1.37
51 ROE Target	9.500%	9.500%	9.500%	9.500%	9.500%	9.500%	9.500%	9.500%	9.500
52 Grossed-Up COC	8.569%	8.569%	8.569%	8.569%	8.569%	8.569%	8.569%	8.569%	8.569
53 OPUC Fee Rate	0.4055%	0.4055%	0.4055%	0.4055%	0.4055%	0.4055%	0.4055%	0.4055%	0.4055
Utility Income Taxes									
54 Book Revenues	(31)	(902)	8,690	(7,180)	(211)	(104)	(156)	-	(51
55 Book Expenses	(1)	(30)	8,661	(7,156)	(210)	(103)	(155)	-	(1
56 Interest Deduction	(7)	(210)	7	(6)	(0)	(0)	(0)	-	(11
57 Production Deduction									
58 Permanent Ms									
59 Deferred Ms									
60 Taxable Income	(23)	(662)	22	(18)	(1)	(0)	(0)	-	(37
61 Current State Tax	(2)	(50)	2	(1)	(0)	(0)	(0)	-	(2
62 State Tax Credits									
63 Net State Taxes	(2)	(50)	2	(1)	(0)	(0)	(0)	-	(2
64 Federal Taxable Income	(21)	(612)	20	(17)	(0)	(0)	(0)	-	(34
65 Current Federal Tax	(4)	(129)	4	(4)	(0)	(0)	(0)	-	(7
66 Federal Tax Credits									
67 Excess ADIT Reversal (ARAM)									
68 Deferred Taxes	-	-	-	-	-	-	-	-	-
69 Total Income Tax Expense	(6)	(179)	6	(5)	(0)	(0)	(0)	-	(10
73 Regulated Net Income	(17)	(484)	16	(13)	(0)	(0)	(0)	-	(27

Non-NVPC Adjustment Detail

	S-8, S-9, S-10 Bundled				S-22, A-20, A-23 Bundled				12/14/21 Proposal						
	Memberships	CAISO Membership	Meals and Entertainment	Bundled Adjjustment	Fuel Stock Adjustment	ADIT - Boardman Removal	Colstrip Smart Burn	Bundled Adjjustment	Remove Faraday	Global to $10MM	Adjust Depreciation to UM 2152	**Total Non-NVPC Adjustments**	**Check**		
1 Sales to Consumers	-	-	-	(726)	-	-	-	(931)	(17,185)	(3,615)	109	(31,639)	(31,639)	TRUE	OK
2 Sales for Resale												-	-	TRUE	OK
3 Other Revenue												165	165	TRUE	OK
4 Total Operating Revenues	-	-	-	(726)	-	-	-	(931)	(17,185)	(3,615)	109	(31,474)	(31,474)	TRUE	OK
5 Net Variable Power Costs												-	-	TRUE	OK
6 Production O&M (Excludes Trojan)												-	-	TRUE	OK
7 Trojan O&M												-	-	TRUE	OK
8 Transmission O&M												-	-	TRUE	OK
9 Distribution O&M												(6,920)	(6,920)	TRUE	OK
10 Customer & MBC O&M												-	-	TRUE	OK
11 Uncollectibles Expense	-	-	-	(2)	-	-	-	(3)	(56)	(12)	0	(103)	(103)	TRUE	OK
12 OPUC Fees	-	-	-	(3)	-	-	-	(4)	(70)	(15)	0	(128)	(128)	TRUE	OK
13 A&G, Ins/Bene., & Gen. Plant	-	-	-	(700)						(2,202)		(3,355)	(3,355)	TRUE	OK
14 Total Operating & Maintenance	-	-	-	(705)	-	-	-	(7)	(126)	(2,228)	1	(10,507)	(10,507)	TRUE	OK
15 Depreciation	-								(5,121)		394	(4,728)	(4,728)	TRUE	OK
16 Amortization											-	-	-	TRUE	OK
17 Property Tax									(1,708)			(1,708)	(1,708)	TRUE	OK
18 Payroll Tax												-	-	TRUE	OK
19 Other Taxes												8,375	8,375	TRUE	OK
20 Franchise Fees	-	-	-	(19)	-	-	-	(24)	(439)	(92)	3	(809)	(809)	TRUE	OK
21 Utility Income Tax	-	-	-	(0)	-	-	-	(185)	(2,007)	(265)	316	(4,723)	(4,723)	TRUE	OK
22 Total Operating Expenses & Taxes	-	-	-	(724)	-	-	-	(215)	(9,402)	(2,586)	713	(14,100)	(14,100)	TRUE	OK
23 **Utility Operating Income**	-	-	-	(2)	-	-	-	(716)	(7,783)	(1,029)	(604)	(17,375)	(17,375)	TRUE	OK
24 **Average Rate Base**															
25 Avg. Gross Plant							-	(10,500)	(119,385)	(15,000)		(164,407)	(164,407)	TRUE	OK
26 Avg. Accum. Deprec. / Amort	-								5,121		(203)	4,918	4,918	TRUE	OK
27 Avg. Accum. Def Tax									381		(8,692)	(14,072)	(14,072)	TRUE	OK
28 Avg. Accum. Def ITC												-	-	TRUE	OK
29 **Avg. Net Utility Plant**	-	-	-	-	-	-	-	(10,500)	(113,882)	(15,000)	(8,895)	(173,561)	(173,561)	TRUE	OK
30 Misc. Deferred Debits												-	-	TRUE	OK
31 Operating Materials & Fuel					-							-	-	TRUE	OK
32 Misc. Deferred Credits												-	-	TRUE	OK
33 Working Cash	-	-	-	(28)	-	-	-	(8)	(366)	(101)	28	(549)	(549)	TRUE	OK
34 **Average Rate Base**	-	-	-	(28)	-	-	-	(10,508)	(114,248)	(15,101)	(8,868)	(174,109)	(174,109)	TRUE	OK
35 **Rate of Return**	#DIV/0!	#DIV/0!	#DIV/0!	6.812%	#DIV/0!	#DIV/0!	#DIV/0!	6.813%	6.813%	6.813%	6.813%	9.979%			
36 **Implied Return on Equity**	#DIV/0!	#DIV/0!	#DIV/0!	9.500%	#DIV/0!	#DIV/0!	#DIV/0!	9.500%	9.500%	9.500%	9.500%	15.834%			
37 Effective Cost of Debt	4.125%	4.125%	4.125%	4.125%	4.125%	4.125%	4.125%	4.125%	4.125%	4.125%	4.125%	4.125%	4.125%		
38 Effective Cost of Preferred	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%		
39 Debt Share of Cap Structure	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%		
40 Preferred Share of Cap Structure	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%		
41 Weighted Cost of Debt	2.063%	2.063%	2.063%	2.063%	2.063%	2.063%	2.063%	2.063%	2.063%	2.063%	2.063%	2.063%	2.063%		
42 Weighted Cost of Preferred	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%		
43 Equity Share of Cap Structure	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%		
44 State Tax Rate	7.594%	7.594%	7.594%	7.594%	7.594%	7.594%	7.594%	7.594%	7.594%	7.594%	7.594%	7.594%	7.594%		
45 Federal Tax Rate	21.000%	21.000%	21.000%	21.000%	21.000%	21.000%	21.000%	21.000%	21.000%	21.000%	21.000%	21.000%	21.000%		
46 Composite Tax Rate	27.000%	27.000%	27.000%	27.000%	27.000%	27.000%	27.000%	27.000%	27.000%	27.000%	27.000%	27.000%	27.000%		
47 Bad Debt Rate	0.326%	0.326%	0.326%	0.326%	0.326%	0.326%	0.326%	0.326%	0.326%	0.326%	0.326%	0.326%	0.326%		
48 Franchise Fee Rate	2.556%	2.556%	2.556%	2.556%	2.556%	2.556%	2.556%	2.556%	2.556%	2.556%	2.556%	2.556%	2.556%		
49 Working Cash Factor	3.891%	3.891%	3.891%	3.891%	3.891%	3.891%	3.891%	3.891%	3.891%	3.891%	3.891%	3.891%	3.891%		
50 Gross-Up Factor	1.370	1.370	1.370	1.370	1.370	1.370	1.370	1.370	1.370	1.370	1.370	1.370	1.370		
51 ROE Target	9.500%	9.500%	9.500%	9.500%	9.500%	9.500%	9.500%	9.500%	9.500%	9.500%	9.500%	9.500%	9.500%		
52 Grossed-Up COC	8.569%	8.569%	8.569%	8.569%	8.569%	8.569%	8.569%	8.569%	8.569%	8.569%	8.569%	8.569%	8.569%		
53 OPUC Fee Rate	0.4055%	0.4055%	0.4055%	0.4055%	0.4055%	0.4055%	0.4055%	0.4055%	0.4055%	0.4055%	0.4055%	0.4055%	0.4055%		
Utility Income Taxes															
54 Book Revenues	-	-	-	(726)	-	-	-	(931)	(17,185)	(3,615)	109	(31,474)	(31,474)	TRUE	OK
55 Book Expenses	-	-	-	(724)	-	-	-	(31)	(7,395)	(2,321)	397	(9,116)	(9,116)	TRUE	OK
56 Interest Deduction	-	-	-	(1)	-	-	-	(217)	(2,356)	(311)	(183)	(3,589)	(3,589)	TRUE	OK
57 Production Deduction												-	-	TRUE	OK
58 Permanent Ms											(1,276)	(1,276)	(1,276)	TRUE	OK
59 Deferred Ms											(14,736)	(14,736)	(14,736)	TRUE	OK
60 Taxable Income	-	-	-	(2)	-	-	-	(684)	(7,434)	(983)	15,906	(2,758)	(2,758)	TRUE	OK
61 Current State Tax	-	-	-	(0)	-	-	-	(52)	(565)	(75)	1,208	(209)	(209)	TRUE	OK
62 State Tax Credits												-	-	TRUE	OK
63 Net State Taxes	-	-	-	(0)	-	-	-	(52)	(565)	(75)	1,208	(209)	(209)	TRUE	OK
64 Federal Taxable Income	-	-	-	(2)	-	-	-	(632)	(6,869)	(908)	14,698	(2,548)	(2,548)	TRUE	OK
65 Current Federal Tax	-	-	-	(0)	-	-	-	(133)	(1,443)	(191)	3,087	(535)	(535)	TRUE	OK
66 Federal Tax Credits												-	-	TRUE	OK
67 Excess ADIT Reversal (ARAM)												-	-	TRUE	OK
68 Deferred Taxes	-	-	-	-	-	-	-	-	-	-	(3,979)	(3,979)	(3,979)	TRUE	OK
69 Total Income Tax Expense	-	-	-	(0)	-	-	-	(185)	(2,007)	(265)	316	(4,723)	(4,723)	TRUE	OK
73 Regulated Net Income	-	-	-	(1)	-	-	-	(499)	(5,427)	(717)	(421)	(13,786)	(13,786)	TRUE	OK

NVPC Adjustment Detail

		7/15/2021 NVPC Update	8/31/2021 Stipulation	10/1/2021 NVPC Update	11/5/2021 NVPC Update	11/15/2021 NVPC Update	Blank	Total NVPC Adjustments	Check		
		(1)	(2)	(3)	(4)	(5)	(6)				
1	Sales to Consumers	1,628	(8,378)	13,903	26,075	209	-	33,437	33,437	TRUE	-
2	Sales for Resale							-	-		
3	Other Revenues							-	-		
4	Total Operating Revenues	1,628	(8,378)	13,903	26,075	209	-	33,437	33,437		
5	Net Variable Power Costs	1,569	(8,075)	13,400	25,131	201		32,227	32,227		
6	Production O&M (Excludes Trojan)							-	-		
7	Trojan O&M							-	-		
8	Transmission O&M							-	-		
9	Distribution O&M							-	-		
10	Customer & MBC O&M							-	-		
11	Uncollectibles Expense	5	(27)	45	85	1	-	109	109		
12	OPUC Fees	7	(34)	56	106	1	-	136	136		
13	A&G, Ins/Bene., & Gen. Plant							-	-		
14	Total Operating & Maintenance	1,581	(8,136)	13,502	25,322	203	-	32,471	32,471		
15	Depreciation							-	-		
16	Amortization							-	-		
17	Property Tax							-	-		
18	Payroll Tax							-	-		
19	Other Taxes							-	-		
20	Franchise Fees	42	(214)	355	666	5	-	855	855		
21	Utility Income Tax	1	(6)	9	18	0	-	23	23		
22	Total Operating Expenses & Taxes	1,623	(8,356)	13,866	26,006	208	-	33,349	33,349		
23	**Utility Operating Income**	4	(22)	37	69	1	-	88	88		
24	**Average Rate Base**										
25	Avg. Gross Plant							-	-		
26	Avg. Accum. Deprec. / Amort							-	-		
27	Avg. Accum. Def Tax							-	-		
28	Avg. Accum. Def ITC							-	-		
29	**Avg. Net Utility Plant**	-	-	-	-	-	-	-	-		
30	Misc. Deferred Debits							-	-		
31	Operating Materials & Fuel							-	-		
32	Misc. Deferred Credits							-	-		
33	Working Cash	63	(325)	539	1,012	8	-	1,297	1,297		
34	**Average Rate Base**	63	(325)	539	1,012	8	-	1,297	1,297		
35	**Rate of Return**	6.813%						6.813%	6.813%		
36	**Implied Return on Equity**	9.500%						9.500%	9.500%		

37	Effective Cost of Debt	4.125%	4.125%	4.125%	4.125%	4.125%	4.125%	4.125%	4.125%
38	Effective Cost of Preferred	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
39	Debt Share of Cap Structure	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%
40	Preferred Share of Cap Structure	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
41	Weighted Cost of Debt	2.063%	2.063%	2.063%	2.063%	2.063%	2.063%	2.063%	2.063%
42	Weighted Cost of Preferred	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
43	Equity Share of Cap Structure	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%
44	State Tax Rate	7.594%	7.594%	7.594%	7.594%	7.594%	7.594%	7.594%	7.594%
45	Federal Tax Rate	21.000%	21.000%	21.000%	21.000%	21.000%	21.000%	21.000%	21.000%
46	Composite Tax Rate	27.000%	27.000%	27.000%	27.000%	27.000%	27.000%	27.000%	27.000%
47	Bad Debt Rate	0.326%	0.326%	0.326%	0.326%	0.326%	0.326%	0.326%	0.326%
48	Franchise Fee Rate	2.556%	2.556%	2.556%	2.556%	2.556%	2.556%	2.556%	2.556%
49	Working Cash Factor	3.891%	3.891%	3.891%	3.891%	3.891%	3.891%	3.891%	3.891%
50	Gross-Up Factor	1.370	1.370	1.370	1.370	1.370	1.370	1.370	1.370
51	ROE Target	9.500%	9.500%	9.500%	9.500%	9.500%	9.500%	9.500%	9.500%
52	Grossed-Up COC	8.569%	8.569%	8.569%	8.569%	8.569%	8.569%	8.569%	8.569%
53	OPUC Fee Rate	0.406%	0.406%	0.406%	0.406%	0.406%	0.406%	0.406%	0.4055%
	Utility Income Taxes								
54	Book Revenues	1,628	(8,378)	13,903	26,075	209	-	33,437	33,437
55	Book Expenses	1,622	(8,350)	13,857	25,989	208	-	33,326	33,326
56	Interest Deduction	1	(7)	11	21	0	-	27	27
57	Production Deduction							-	-
58	Permanent Ms							-	-
59	Deferred Ms							-	-
60	Taxable Income	4	(21)	35	66	1	-	84	84
61	Current State Tax	0	(2)	3	5	0	-	6	6
62	State Tax Credits							-	-
63	Net State Taxes	0	(2)	3	5	0	-	6	6
64	Federal Taxable Income	4	(20)	32	61	0	-	78	78
65	Current Federal Tax	1	(4)	7	13	0	-	16	16
66	Federal Tax Credits							-	-
67	ITC Amort							-	-
68	Deferred Taxes	-	-	-	-	-	-	-	-
69	Total Income Tax Expense	1	(6)	9	18	0	-	23	23
73	Regulated Net Income	3	(15)	26	48	0	-	62	62

Category A Advertising
Adjust Result to 1/8 of 1% per OAR

9090001 CustSvc-InformAdvertisingExp	2,035,889
Less: Legally Mandated Advertising	5,257
	2,030,632
2022 Total Revenue Requirement	2,106,801
Factor per OAR	0.125%
Presumed Reasonable Cat A Costs	2,633,501
Total Adjustment	-

Production Tax Credits (PTCs) in 2022 Net Variable Power Cost

Grossed Up for Taxes	(40,431)
Gross Up Factor	1.3696
PTCs	(29,519)

COMPOSITE COST OF CAPITAL

UE 394	Average Outstanding	Percent of Capital	Percent Cost	Weighted Percent Cost
Long Term Debt		50.000%	4.125%	2.063%
Preferred Stock		0.000%	0.000%	0.000%
Common Equity		50.000%	9.500%	4.750%
Total	0	100.000%		6.813%

::

REVENUE SENSITIVE COSTS USED TEST YEAR REVENUE REQUIREMENT MODEL

Revenue Sensitive Costs		UE 394
Revenues		1.00000
Customer Accts/Other O&M: Uncollectibles		0.3264%
Other Taxes: Franchise Fees		2.5558%
Short-term Interest		0.0000%
A&G: OPUC Gross Rev. Fee		0.4055%
		0.96712
State Income Tax @	7.594%	0.07345
Federal Taxable Income		0.89368
Federal Income Tax @	21.00%	0.18767
ITC		0.00000
Current FIT		0.18767
Environmental Tax @	0.00%	0.00000
Total Income Taxes		0.26112
Total Revenue Sensitive Costs		0.29400
Utility Operating Income		0.70600
Gross-up Factor		1.3699
Grossed up CoC		8.569%

Other Factors	
Working Cash	3.891%
Composite Tax Rate	27.000%

Revenue Sensitive Costs are applied only to Sales-to-Consumers, they are not to be applied to Total Operating Revenue.

Portland General Electric
UE-394, 2022 Test Year
Regulatory Adjustments
($000)

	NVPC	S-3	S-4	S-6	S-12 / A-24 / C-3	A-5	A-6	A-7	A-11	A-18	Portion of S-23	A-26	C-4
	Adj / Updates	Excitation System	Beaver Modernization	OCAT	Level III Accrual	Directors' Def Compensation	D&O Ins	Directors' Expenses	R&D	ADIT-Incentives	IOC	Trojan Sch. 136	Campgound Revenue
Sales to Consumers													
Other Revenues													165
Total Operating Revenues	-	-	-	-	-	-	-	-	-	-	-	-	165
Net Variable Power Cost	32,227												
Fixed Plant Cost													
Transmission O&M													
Distribution O&M					(6,920)							-	
Total Fixed O&M	-	-	-	-	(6,920)	-	-	-	-	-	-	-	-
Customer Accounts													
Uncollectibles per Rev Req Model	-	-	-	-	-	-	-	-	-	-	-	-	-
Customer Service & Sales						-							-
OPUC Fee	-	-	-	-	-	-	-	-	-	-	-	-	-
Admin. & General						(203)	(100)	(150)	-	-			
Other O&M	-	-	-	-	-	(203)	(100)	(150)	-	-	-	-	-
Total Operating & Maintenance	32,227	-	-	-	(6,920)	(203)	(100)	(150)	-	-	-	-	-
Depreciation & Amortization													
Other Taxes				8,375									
Franchise Fee	-	-	-	-	-	-	-	-	-	-	-	-	-
Income Taxes	(8,706)	2	57	(2,263)	1,869	55	27	41	-	32	50	-	45
Total Oper. Expenses & Taxes	23,521	2	57	6,112	(5,051)	(148)	(73)	(109)	-	32	50	-	45
Utility Operating Income	(23,521)	(2)	(57)	(6,112)	5,051	148	73	109	-	(32)	(50)	-	120
Average Rate Base													
Avg. Gross Plant		(350)	(10,172)								(9,000)		
Avg. Accum. Deprec.													
Avg. Accum. Def Tax										5,761			
Avg. Accum. Def ITC													
Avg. Net Utility Plant	-	(350)	(10,172)	-	-	-	-	-	-	(5,761)	(9,000)	-	-
Operating Materials & Fuel													
Deferred Programs & Investments													
Misc. Deferred Credits													
Working Cash	915	0	2	238	(196)	(6)	(3)	(4)	-	1	2	-	2
Average Rate Base	915	(350)	(10,170)	238	(196)	(6)	(3)	(4)	-	(5,760)	(8,998)	-	2
Rate of Return													
Implied Return on Equity													
Income Taxes													
Book Revenues	-	-	-	-	-	-	-	-	-	-	-	-	165
Book Expenses	32,227	-	-	8,375	(6,920)	(203)	(100)	(150)	-	-	-	-	-
Interest @ Weighted Cost of Debt	19	(7)	(210)	5	(4)	(0)	(0)	(0)	-	(119)	(186)	-	0
Production Deduction													
Temporary Sch M Differences	-	-	-	-	-	-	-	-	-	-	-	-	-
Permanent M Differences	-	-	-	-	-	-	-	-	-	-	-	-	-
State Taxable Income	(32,246)	7	210	(8,380)	6,924	203	100	150	-	119	186	-	165
State Income Tax	(2,449)	1	16	(636)	526	15	8	11	-	9	14	-	13
State Tax Credit	-	-	-	-	-	-	-	-	-	-	-	-	-
Net State Income Tax	(2,449)	1	16	(636)	526	15	8	11	-	9	14	-	13
Federal Taxable Income	(29,797)	7	194	(7,744)	6,398	188	92	139	-	110	171	-	152
Fed Tax @ 35%	(6,257)	1	41	(1,626)	1,344	39	19	29	-	23	36	-	32
Federal Tax Credits													
Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-
Excess ADIT Reversal (ARAM)													
Total Income Tax	(8,706)	2	57	(2,263)	1,869	55	27	41	-	32	50	-	45

S-8, S-9, S-10 Bundled	S-22, A-20, A-23 Bundled	12/13/21 Proposal													
Bundled Adjjustment	Bundled Adjjustment	Remove Faraday	Global to $10MM	Adjust Depreciation to UM 2152	Blank-18	Blank-19	Blank-20	Blank 21	Blank 22	Blank 23	Blank 24	Blank 25	Blank 26	Blank 27	Blank 28
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
		-													
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(700)			(2,202)		-				-						
(700)	-	-	(2,202)	-	-	-	-	-	-	-	-	-	-	-	-
(700)	-	-	(2,202)	-	-	-	-	-	-	-	-	-	-	-	-
		(5,121)	-	387						-					
		(1,708)	-			-									
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
189	58	2,479	678	289	-	-	-	-	-	-	-	-	-	-	-
(511)	58	(4,351)	(1,524)	676	-	-	-	-	-	-	-	-	-	-	-
511	(58)	4,351	1,524	(676)	-	-	-	-	-	-	-	-	-	-	-
	(10,500)	(119,385)	(15,000)						-						
		(5,121)		197											
		(381)		8,694											
-	(10,500)	(113,882)	(15,000)	(8,892)	-	-	-	-	-	-	-	-	-	-	-
(20)	2	(169)	(59)	26	-	-	-	-	-	-	-	-	-	-	-
(20)	(10,498)	(114,052)	(15,059)	(8,865)	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(700)	-	(6,830)	(2,202)	387	-	-	-	-	-	-	-	-	-	-	-
(0)	(217)	(2,352)	(311)	(183)	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	(14,741)		-	-				-	-	-	-	-
-	-		-	(1,276)	-	-	-				-	-	-	-	-
700	217	9,182	2,513	15,813	-	-	-	-	-	-	-	-	-	-	-
53	16	697	191	1,201	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-		-	-	-	-	-	-	-	-
53	16	697	191	1,201	-	-	-	-	-	-	-	-	-	-	-
647	200	8,485	2,322	14,612	-	-	-	-	-	-	-	-	-	-	-
136	42	1,782	488	3,068	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	(3,980)	-	-	-	-	-	-	-	-	-	-	-
189	58	2,479	678	289	-	-	-	-	-	-	-	-	-	-	-

Blank 29	Blank 30	Blank 31	Blank 32	Blank 33	Blank 34	Blank 35	Blank 36	Blank 37	Blank 38	Blank 39	Blank 40	Blank 41	Total Adjustments
													-
													165
-	-	-	-	-	-	-	-	-	-	-	-	-	165
													32,227
													-
													-
													(6,920)
-	-	-	-	-	-	-	-	-	-	-	-	-	(6,920)
													-
-	-	-	-	-	-	-	-	-	-	-	-	-	-
													-
-	-	-	-	-	-	-	-	-	-	-	-	-	-
													(3,355)
-	-	-	-	-	-	-	-	-	-	-	-	-	(3,355)
-	-	-	-	-	-	-	-	-	-	-	-	-	21,952
													(4,735)
													6,667
-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	(5,097)
-	-	-	-	-	-	-	-	-	-	-	-	-	18,787
-	-	-	-	-	-	-	-	-	-	-	-	-	(18,622)
													(164,407)
													(4,924)
													14,075
													-
-	-	-	-	-	-	-	-	-	-	-	-	-	(173,557)
													-
													-
													-
-	-	-	-	-	-	-	-	-	-	-	-	-	731
-	-	-	-	-	-	-	-	-	-	-	-	-	(172,826)
-	-	-	-	-	-	-	-	-	-	-	-	-	165
-	-	-	-	-	-	-	-	-	-	-	-	-	23,884
-	-	-	-	-	-	-	-	-	-	-	-	-	(3,565)
-	-	-	-	-	-	-	-	-	-	-	-	-	(14,741)
-	-	-	-	-	-	-	-	-	-	-	-	-	(1,276)
-	-	-	-	-	-	-	-	-	-	-	-	-	(4,138)
-	-	-	-	-	-	-	-	-	-	-	-	-	(314)
-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	(314)
-	-	-	-	-	-	-	-	-	-	-	-	-	(3,823)
-	-	-	-	-	-	-	-	-	-	-	-	-	(803)
													-
-	-	-	-	-	-	-	-	-	-	-	-	-	(3,980)
													-
-	-	-	-	-	-	-	-	-	-	-	-	-	(5,097)

Factors for Adjustments

	Generation	Transmission	Distribution	Ancillary	Metering	Billing	Consumer	Retail*	Total
Support / Labor Allocation	22.1%	4.0%	50.2%	0.0%	0.9%	3.2%	19.6%	0.0%	100.00%
MBC Allocation					3.8%	13.6%	82.6%	0.0%	100.00%
Property Taxes / Net Plant	45.6%	9.8%	41.0%	0.0%	0.3%	0.9%	2.4%	0.0%	100.00%
Depreciation	44.3%	6.3%	46.0%	0.0%	0.1%	0.5%	2.8%	0.0%	100.00%
Accumulated Depreciation	40.5%	7.1%	48.6%	0.0%	0.8%	0.7%	2.3%	0.0%	100.00%
Accum. Deferred Taxes	66.1%	9.1%	22.8%	0.0%	0.3%	0.5%	1.2%	0.0%	100.00%
Other Revenue	-9.8%	54.1%	55.7%	0.0%	0.0%	0.0%	0.0%	0.0%	100.00%
Rate Base	43.9%	9.9%	42.6%	0.0%	0.3%	1.0%	2.4%	0.0%	100.00%
IOC	31.6%	23.5%	38.3%	0.0%	0.2%	0.6%	5.7%	0.0%	100.00%
Blank	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.00%
Revenue Reqirements	53.3%	4.1%	34.4%	0.0%	0.3%	1.8%	6.1%	0.0%	100.00%

Note:
* All adjustments are to regulatory costs so no amounts are allocated to retail.

	Generation	Transmission	Distribution	Ancillary	Metering	Billing	Consumer	Retail*
Pre-Adjustment Revenue Requirements	$1,114,341	$86,476	$720,019	$0	$6,194	$37,715	$127,220	$2,091,966

Portland General Electric
UE-394, 2022 Test Year
Stipulated Adjustments
($000)

	NVPC Adj / Updates	Prod. Cost	Transmsn. Cost	Dist. Cost	Ancillary Services	Metering Cost	Billing Cost	Other Consumer Cost	PGE Regulated Rev Req	Retail	Check Total
Sales to Consumers									-		-
Other Revenues									-		-
Total Operating Revenues	-	-	-	-	-	-	-	-	-	-	-
Net Variable Power Cost	32,227	32,227							32,227		32,227
Fixed Plant Cost									-		-
Transmission O&M									-		-
Distribution O&M									-		-
Total Fixed O&M	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts									-		-
Uncollectibles per Rev Req Model									-		-
Customer Service & Sales									-		-
OPUC Fee									-		
Admin. & General									-		-
Other O&M	-	-	-	-	-	-	-	-	-	-	-
Total Operating & Maintenance	32,227	32,227	-	-	-	-	-	-	32,227	-	32,227
Depreciation & Amortization									-		-
Other Taxes									-		-
Franchise Fee									-		-
Income Taxes	(8,706)	(8,706)	-	-	-	-	-	-	(8,706)	-	(8,706)
Total Oper. Expenses & Taxes	23,521	23,521	-	-	-	-	-	-	23,521	-	23,521
Utility Operating Income	(23,521)	(23,521)	-	-	-	-	-	-	(23,521)	-	(23,521)
Average Rate Base											
Avg. Gross Plant									-		-
Avg. Accum. Deprec.									-		-
Avg. Accum. Def Tax									-		-
Avg. Accum. Def ITC									-		-
Avg. Net Utility Plant	-	-	-	-	-	-	-	-	-	-	-
Operating Materials & Fuel									-		-
Deferred Programs & Investments									-		-
Misc. Deferred Credits									-		-
Working Cash	915	915	-	-	-	-	-	-	915	-	915
Average Rate Base	915	915	-	-	-	-	-	-	915	-	915
Rate of Return											
Implied Return on Equity											
Income Taxes											
Book Revenues	-	-	-	-	-	-	-	-	-	-	-
Book Expenses	32,227	32,227	-	-	-	-	-	-	32,227	-	32,227
Interest @ Weighted Cost of Debt	19	19	-	-	-	-	-	-	19	-	19
Production Deduction									-		-
Temporary Sch M Differences	-	-	-	-	-	-	-	-	-	-	-
Permanent M Differences	-	-	-	-	-	-	-	-	-	-	-
State Taxable Income	(32,246)	(32,246)	-	-	-	-	-	-	(32,246)	-	(32,246)
State Income Tax	(2,449)	(2,449)	-	-	-	-	-	-	(2,449)	-	(2,449)
State Tax Credit	-	-	-	-	-	-	-	-	-	-	-
Net State Income Tax	(2,449)	(2,449)	-	-	-	-	-	-	(2,449)	-	(2,449)
Federal Taxable Income	(29,797)	(29,797)	-	-	-	-	-	-	(29,797)	-	(29,797)
Fed Tax @ 35%	(6,257)	(6,257)	-	-	-	-	-	-	(6,257)	-	(6,257)
Federal Tax Credits									-		-
Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-
Excess ADIT Reversal (ARAM)	-	-	-	-	-	-	-	-	-	-	-
Total Income Tax	(8,706)	(8,706)	-	-	-	-	-	-	(8,706)	-	(8,706)

Portland General Electric
UE-394, 2022 Test Year
Adjustments
($000)

	0 S-3 ExcitationSystem	Prod. Cost	Transmsn. Cost	Dist. Cost	Ancillary Services	Metering Cost	Billing Cost	Other Consumer Cost	PGE Regulated Rev Req	Retail	Check Total
Sales to Consumers									-		-
Other Revenues									-	-	-
Total Operating Revenues	-	-	-	-	-	-	-	-	-	-	-
Net Variable Power Cost									-		-
Fixed Plant Cost									-		-
Transmission O&M									-		-
Distribution O&M									-		-
Total Fixed O&M	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts									-		-
Uncollectibles per Rev Req Model									-		-
Customer Service & Sales									-		-
OPUC Fee									-		
Admin. & General									-		-
Other O&M	-	-	-	-	-	-	-	-	-	-	-
Total Operating & Maintenance	-	-	-	-	-	-	-	-	-	-	-
Depreciation & Amortization									-	-	-
Other Taxes									-		-
Franchise Fee									-		-
Income Taxes	2	-	-	2	-	-	-	-	2	-	2
Total Oper. Expenses & Taxes	2	-	-	2	-	-	-	-	2	-	2
Utility Operating Income	(2)	-	-	(2)	-	-	-	-	(2)	-	(2)
Average Rate Base											
Avg. Gross Plant	(350)			(350)					(350)		(350)
Avg. Accum. Deprec.									-		-
Avg. Accum. Def Tax									-		-
Avg. Accum. Def ITC									-		-
Avg. Net Utility Plant	(350)	-	-	(350)	-	-	-	-	(350)	-	(350)
Operating Materials & Fuel									-		-
Deferred Programs & Investments									-		-
Misc. Deferred Credits									-		-
Working Cash	0	-	-	0	-	-	-	-	0	-	0
Average Rate Base	(350)	-	-	(350)	-	-	-	-	(350)	-	(350)
Rate of Return											
Implied Return on Equity											
Income Taxes											
Book Revenues	-	-	-	-	-	-	-	-	-	-	-
Book Expenses	-	-	-	-	-	-	-	-	-	-	-
Interest @ Weighted Cost of Debt	(7)	-	-	(7)	-	-	-	-	(7)	-	(7)
Production Deduction									-		-
Temporary Sch M Differences									-		-
Permanent M Differences									-		-
State Taxable Income	7	-	-	7	-	-	-	-	7	-	7
State Income Tax	1	-	-	1	-	-	-	-	1	-	1
State Tax Credit									-		-
Net State Income Tax	1	-	-	1	-	-	-	-	1	-	1
Federal Taxable Income	7	-	-	7	-	-	-	-	7	-	7
Fed Tax @ 35%	1	-	-	1	-	-	-	-	1	-	1
Federal Tax Credits									-		-
Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-
Excess Deferred Income Tax Reversal (ARAM)	-	-	-	-	-	-	-	-	-	-	-
Total Income Tax	2	-	-	2	-	-	-	-	2	-	2

Portland General Electric
UE-394, 2022 Test Year
Adjustments
($000)

	0 S-4 BeaverModernization	Prod. Cost	Transmsn. Cost	Dist. Cost	Ancillary Services	Metering Cost	Billing Cost	Other Consumer Cost	PGE Regulated Rev Req	Retail	Check Total
Sales to Consumers									-		-
Other Revenues									-		-
Total Operating Revenues	-	-	-	-	-	-	-	-	-	-	-
Net Variable Power Cost									-		-
Fixed Plant Cost									-		-
Transmission O&M									-		-
Distribution O&M				-					-		-
Total Fixed O&M	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts									-		-
Uncollectibles per Rev Req Model									-		-
Customer Service & Sales									-		-
OPUC Fee									-		
Admin. & General		-	-	-	-	-	-	-	-	-	-
Other O&M	-	-	-	-	-	-	-	-	-	-	-
Total Operating & Maintenance	-	-	-	-	-	-	-	-	-	-	-
Depreciation & Amortization									-		-
Other Taxes									-		-
Franchise Fee									-		-
Income Taxes	57	57	-	-	-	-	-	-	57	-	57
Total Oper. Expenses & Taxes	57	57	-	-	-	-	-	-	57	-	57
Utility Operating Income	(57)	(57)	-	-	-	-	-	-	(57)	-	(57)
Average Rate Base											
Avg. Gross Plant	(10,172)	(10,172)							(10,172)		(10,172)
Avg. Accum. Deprec.									-		-
Avg. Accum. Def Tax									-		-
Avg. Accum. Def ITC									-		-
Avg. Net Utility Plant	(10,172)	(10,172)	-	-	-	-	-	-	(10,172)	-	(10,172)
Operating Materials & Fuel									-		-
Deferred Programs & Investments									-		-
Misc. Deferred Credits									-		-
Working Cash	2	2	-	-	-	-	-	-	2	-	2
Average Rate Base	(10,170)	(10,170)	-	-	-	-	-	-	(10,170)	-	(10,170)
Rate of Return											
Implied Return on Equity											
Income Taxes											
Book Revenues	-	-	-	-	-	-	-	-	-	-	-
Book Expenses	-	-	-	-	-	-	-	-	-	-	-
Interest @ Weighted Cost of Debt	(210)	(210)	-	-	-	-	-	-	(210)	-	(210)
Production Deduction									-		-
Temporary Sch M Differences									-		-
Permanent M Differences									-		-
State Taxable Income	210	210	-	-	-	-	-	-	210	-	210
State Income Tax	16	16	-	-	-	-	-	-	16	-	16
State Tax Credit									-		-
Net State Income Tax	16	16	-	-	-	-	-	-	16	-	16
Federal Taxable Income	194	194	-	-	-	-	-	-	194	-	194
Fed Tax @ 35%	41	41	-	-	-	-	-	-	41	-	41
Federal Tax Credits									-		-
Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-
Excess Deferred Income Tax Reversal (ARAM)	-	-	-	-	-	-	-	-	-	-	-
Total Income Tax	57	57	-	-	-	-	-	-	57	-	57

Portland General Electric
UE-394, 2022 Test Year
Adjustments
($000)

	0 S-6 OCAT	Prod. Cost	Transmsn. Cost	Dist. Cost	Ancillary Services	Metering Cost	Billing Cost	Other Consumer Cost	PGE Regulated Rev Req	Retail	Check Total
Sales to Consumers									-		-
Other Revenues									-		-
Total Operating Revenues	-	-	-	-	-	-	-	-	-	-	-
Net Variable Power Cost									-		-
Fixed Plant Cost									-		-
Transmission O&M									-		-
Distribution O&M									-		-
Total Fixed O&M	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts									-		-
Uncollectibles per Rev Req Model									-		-
Customer Service & Sales									-		-
OPUC Fee									-		
Admin. & General		-	-	-	-	-	-	-	-	-	-
Other O&M	-	-	-	-	-	-	-	-	-	-	-
Total Operating & Maintenance	-	-	-	-	-	-	-	-	-	-	-
Depreciation & Amortization									-		-
Other Taxes	8,375	4,461	346	2,883	-	25	151	509	8,375		8,375
Franchise Fee									-		-
Income Taxes	(2,263)	(1,205)	(94)	(779)	-	(7)	(41)	(138)	(2,263)	-	(2,263)
Total Oper. Expenses & Taxes	6,112	3,256	253	2,104	-	18	110	372	6,112	-	6,112
Utility Operating Income	(6,112)	(3,256)	(253)	(2,104)	-	(18)	(110)	(372)	(6,112)	-	(6,112)
Average Rate Base											
Avg. Gross Plant									-		-
Avg. Accum. Deprec.									-		-
Avg. Accum. Def Tax									-		-
Avg. Accum. Def ITC									-		-
Avg. Net Utility Plant	-	-	-	-	-	-	-	-	-	-	-
Operating Materials & Fuel									-		-
Deferred Programs & Investments									-		-
Misc. Deferred Credits									-		-
Working Cash	238	127	10	82	-	1	4	14	238	-	238
Average Rate Base	238	127	10	82	-	1	4	14	238	-	238

Rate of Return											
Implied Return on Equity											
Income Taxes											
Book Revenues	-	-	-	-	-	-	-	-	-	-	-
Book Expenses	8,375	4,461	346	2,883	-	25	151	509	8,375	-	8,375
Interest @ Weighted Cost of Debt	5	3	0	2	-	0	0	0	5	-	5
Production Deduction									-		-
Temporary Sch M Differences									-		-
Permanent M Differences									-		-
State Taxable Income	(8,380)	(4,464)	(346)	(2,884)	-	(25)	(151)	(510)	(8,380)	-	(8,380)
State Income Tax	(636)	(339)	(26)	(219)	-	(2)	(11)	(39)	(636)	-	(636)
State Tax Credit									-		-
Net State Income Tax	(636)	(339)	(26)	(219)	-	(2)	(11)	(39)	(636)	-	(636)
Federal Taxable Income	(7,744)	(4,125)	(320)	(2,665)	-	(23)	(140)	(471)	(7,744)	-	(7,744)
Fed Tax @ 35%	(1,626)	(866)	(67)	(560)	-	(5)	(29)	(99)	(1,626)	-	(1,626)
Federal Tax Credits									-		-
Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-
Excess Deferred Income Tax Reversal (ARAM)	-	-	-	-	-	-	-	-	-	-	-
Total Income Tax	(2,263)	(1,205)	(94)	(779)	-	(7)	(41)	(138)	(2,263)	-	(2,263)

Portland General Electric
UE-394, 2022 Test Year
Adjustments
($000)

	S-12 / A-24 / C-3 Level IIIAccrual	Prod. Cost	Transmsn. Cost	Dist. Cost	Ancillary Services	Metering Cost	Billing Cost	Other Consumer Cost	PGE Regulated Rev Req	Retail	Check Total
Sales to Consumers									-		-
Other Revenues									-		-
Total Operating Revenues	-	-	-	-	-	-	-	-	-	-	-
Net Variable Power Cost									-		-
Fixed Plant Cost									-		-
Transmission O&M									-		-
Distribution O&M	(6,920)			(6,920)					(6,920)		(6,920)
Total Fixed O&M	(6,920)	-	-	(6,920)	-	-	-	-	(6,920)	-	(6,920)
Customer Accounts									-		-
Uncollectibles per Rev Req Model									-		-
Customer Service & Sales									-		-
OPUC Fee									-		
Admin. & General		-	-	-	-	-	-	-	-	-	-
Other O&M	-	-	-	-	-	-	-	-	-	-	-
Total Operating & Maintenance	(6,920)	-	-	(6,920)	-	-	-	-	(6,920)	-	(6,920)
Depreciation & Amortization		-	-	-	-	-	-	-	-	-	-
Other Taxes		-	-	-	-	-	-	-	-	-	-
Franchise Fee									-		-
Income Taxes	1,869	-	-	1,869	-	-	-	-	1,869	-	1,869
Total Oper. Expenses & Taxes	(5,051)	-	-	(5,051)	-	-	-	-	(5,051)	-	(5,051)
Utility Operating Income	5,051	-	-	5,051	-	-	-	-	5,051	-	5,051
Average Rate Base											
Avg. Gross Plant		-	-	-	-	-	-	-	-	-	-
Avg. Accum. Deprec.									-		-
Avg. Accum. Def Tax									-		-
Avg. Accum. Def ITC									-		-
Avg. Net Utility Plant	-	-	-	-	-	-	-	-	-	-	-
Operating Materials & Fuel									-		-
Deferred Programs & Investments									-		-
Misc. Deferred Credits									-		-
Working Cash	(196)	-	-	(196)	-	-	-	-	(196)	-	(196)
Average Rate Base	(196)	-	-	(196)	-	-	-	-	(196)	-	(196)
Rate of Return											
Implied Return on Equity											
Income Taxes											
Book Revenues	-	-	-	-	-	-	-	-	-	-	-
Book Expenses	(6,920)	-	-	(6,920)	-	-	-	-	(6,920)	-	(6,920)
Interest @ Weighted Cost of Debt	(4)	-	-	(4)	-	-	-	-	(4)	-	(4)
Production Deduction									-		-
Temporary Sch M Differences									-		-
Permanent M Differences									-		-
State Taxable Income	6,924	-	-	6,924	-	-	-	-	6,924	-	6,924
State Income Tax	526	-	-	526	-	-	-	-	526	-	526
State Tax Credit									-		-
Net State Income Tax	526	-	-	526	-	-	-	-	526	-	526
Federal Taxable Income	6,398	-	-	6,398	-	-	-	-	6,398	-	6,398
Fed Tax @ 35%	1,344	-	-	1,344	-	-	-	-	1,344	-	1,344
Federal Tax Credits									-		-
Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-
Excess Deferred Income Tax Reversal (ARAM)	-	-	-	-	-	-	-	-	-	-	-
Total Income Tax	1,869	-	-	1,869	-	-	-	-	1,869	-	1,869

Portland General Electric
UE-394, 2022 Test Year
Adjustments
($000)

	0 A-5 Directors' Def Compens:	Prod. Cost	Transmsn. Cost	Dist. Cost	Ancillary Services	Metering Cost	Billing Cost	Other Consumer Cost	PGE Regulated Rev Req	Retail	Check Total
Sales to Consumers									-		-
Other Revenues									-		-
Total Operating Revenues	-	-	-	-	-	-	-	-	-	-	-
Net Variable Power Cost									-		-
Fixed Plant Cost		-							-		-
Transmission O&M									-		-
Distribution O&M									-		-
Total Fixed O&M	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts									-		-
Uncollectibles per Rev Req Model									-		-
Customer Service & Sales	-							-	-		-
OPUC Fee									-		
Admin. & General	(203)	(45)	(8)	(102)	-	(2)	(7)	(40)	(203)		(203)
Other O&M	(203)	(45)	(8)	(102)	-	(2)	(7)	(40)	(203)	-	(203)
Total Operating & Maintenance	(203)	(45)	(8)	(102)	-	(2)	(7)	(40)	(203)	-	(203)
Depreciation & Amortization									-		-
Other Taxes									-		-
Franchise Fee									-		-
Income Taxes	55	12	2	28	-	0	2	11	55	-	55
Total Oper. Expenses & Taxes	(148)	(33)	(6)	(74)	-	(1)	(5)	(29)	(148)	-	(148)
Utility Operating Income	148	33	6	74	-	1	5	29	148	-	148
Average Rate Base											
Avg. Gross Plant									-		-
Avg. Accum. Deprec.									-		-
Avg. Accum. Def Tax									-		-
Avg. Accum. Def ITC									-		-
Avg. Net Utility Plant	-	-	-	-	-	-	-	-	-	-	-
Operating Materials & Fuel									-		-
Deferred Programs & Investments									-		-
Misc. Deferred Credits									-		-
Working Cash	(6)	(1)	(0)	(3)	-	(0)	(0)	(1)	(6)	-	(6)
Average Rate Base	(6)	(1)	(0)	(3)	-	(0)	(0)	(1)	(6)	-	(6)
Rate of Return											
Implied Return on Equity											
Income Taxes											
Book Revenues	-	-	-	-	-	-	-	-	-	-	-
Book Expenses	(203)	(45)	(8)	(102)	-	(2)	(7)	(40)	(203)	-	(203)
Interest @ Weighted Cost of Debt	(0)	(0)	(0)	(0)	-	(0)	(0)	(0)	(0)	-	(0)
Production Deduction									-		-
Temporary Sch M Differences									-		-
Permanent M Differences									-		-
State Taxable Income	203	45	8	102	-	2	7	40	203	-	203
State Income Tax	15	3	1	8	-	0	0	3	15	-	15
State Tax Credit									-		-
Net State Income Tax	15	3	1	8	-	0	0	3	15	-	15
Federal Taxable Income	188	41	8	94	-	2	6	37	188	-	188
Fed Tax @ 35%	39	9	2	20	-	0	1	8	39	-	39
Federal Tax Credits									-		-
Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-
Excess Deferred Income Tax Reversal (ARAM)	-	-	-	-	-	-	-	-	-	-	-
Total Income Tax	55	12	2	28	-	0	2	11	55	-	55

Portland General Electric
UE-394, 2022 Test Year
Adjustments
($000)

	A-6 D&O Ins	Prod. Cost	Transmsn. Cost	Dist. Cost	Ancillary Services	Metering Cost	Billing Cost	Other Consumer Cost	PGE Regulated Rev Req	Retail	Check Total
Sales to Consumers									-		-
Other Revenues									-		-
Total Operating Revenues	-	-	-	-	-	-	-	-	-	-	-
Net Variable Power Cost									-		-
Fixed Plant Cost									-		-
Transmission O&M									-		-
Distribution O&M									-		-
Total Fixed O&M	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts								-	-		-
Uncollectibles per Rev Req Model									-		-
Customer Service & Sales									-		-
OPUC Fee									-		
Admin. & General	(100)	(22)	(4)	(50)	-	(1)	(3)	(20)	(100)	-	(100)
Other O&M	(100)	(22)	(4)	(50)	-	(1)	(3)	(20)	(100)	-	(100)
Total Operating & Maintenance	(100)	(22)	(4)	(50)	-	(1)	(3)	(20)	(100)	-	(100)
Depreciation & Amortization									-		-
Other Taxes									-		-
Franchise Fee									-		-
Income Taxes	27	6	1	14	-	0	1	5	27	-	27
Total Oper. Expenses & Taxes	(73)	(16)	(3)	(37)	-	(1)	(2)	(14)	(73)	-	(73)
Utility Operating Income	73	16	3	37	-	1	2	14	73	-	73
Average Rate Base											
Avg. Gross Plant									-		-
Avg. Accum. Deprec.									-		-
Avg. Accum. Def Tax									-		-
Avg. Accum. Def ITC									-		-
Avg. Net Utility Plant	-	-	-	-	-	-	-	-	-	-	-
Operating Materials & Fuel									-		-
Deferred Programs & Investments									-		-
Misc. Deferred Credits									-		-
Working Cash	(3)	(1)	(0)	(1)	-	(0)	(0)	(1)	(3)	-	(3)
Average Rate Base	(3)	(1)	(0)	(1)	-	(0)	(0)	(1)	(3)	-	(3)
Rate of Return											
Implied Return on Equity											
Income Taxes											
Book Revenues	-	-	-	-	-	-	-	-	-	-	-
Book Expenses	(100)	(22)	(4)	(50)	-	(1)	(3)	(20)	(100)	-	(100)
Interest @ Weighted Cost of Debt	(0)	(0)	(0)	(0)	-	(0)	(0)	(0)	(0)	-	(0)
Production Deduction									-		-
Temporary Sch M Differences									-		-
Permanent M Differences		-							-		-
State Taxable Income	100	22	4	50	-	1	3	20	100	-	100
State Income Tax	8	2	0	4	-	0	0	1	8	-	8
State Tax Credit									-		-
Net State Income Tax	8	2	0	4	-	0	0	1	8	-	8
Federal Taxable Income	92	20	4	46	-	1	3	18	92	-	92
Fed Tax @ 35%	19	4	1	10	-	0	1	4	19	-	19
Federal Tax Credits									-		-
Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-
Excess Deferred Income Tax Reversal (ARAM)	-	-	-	-	-	-	-	-	-	-	-
Total Income Tax	27	6	1	14	-	0	1	5	27	-	27

Portland General Electric
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Adjustments
($000)

	A-7 Directors' Expenses	Prod. Cost	Transmsn. Cost	Dist. Cost	Ancillary Services	Metering Cost	Billing Cost	Other Consumer Cost	PGE Regulated Rev Req	Retail	Check Total
Sales to Consumers									-		-
Other Revenues		-	-	-	-	-	-	-	-	-	-
Total Operating Revenues	-	-	-	-	-	-	-	-	-	-	-
Net Variable Power Cost									-		-
Fixed Plant Cost									-		-
Transmission O&M									-		-
Distribution O&M									-		-
Total Fixed O&M	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts							-		-		-
Uncollectibles per Rev Req Model									-		-
Customer Service & Sales									-		-
OPUC Fee									-		
Admin. & General	(150)	(33)	(6)	(75)	-	(1)	(5)	(29)	(150)	-	(150)
Other O&M	(150)	(33)	(6)	(75)	-	(1)	(5)	(29)	(150)	-	(150)
Total Operating & Maintenance	(150)	(33)	(6)	(75)	-	(1)	(5)	(29)	(150)	-	(150)
Depreciation & Amortization									-		-
Other Taxes									-		-
Franchise Fee									-		-
Income Taxes	41	9	2	20	-	0	1	8	41	-	41
Total Oper. Expenses & Taxes	(109)	(24)	(4)	(55)	-	(1)	(4)	(21)	(109)	-	(109)
Utility Operating Income	109	24	4	55	-	1	4	21	109	-	109
Average Rate Base											
Avg. Gross Plant									-		-
Avg. Accum. Deprec.									-		-
Avg. Accum. Def Tax									-		-
Avg. Accum. Def ITC									-		-
Avg. Net Utility Plant	-	-	-	-	-	-	-	-	-	-	-
Operating Materials & Fuel									-		-
Deferred Programs & Investments									-		-
Misc. Deferred Credits									-		-
Working Cash	(4)	(1)	(0)	(2)	-	(0)	(0)	(1)	(4)	-	(4)
Average Rate Base	(4)	(1)	(0)	(2)	-	(0)	(0)	(1)	(4)	-	(4)
Rate of Return											
Implied Return on Equity											
Income Taxes											
Book Revenues	-	-	-	-	-	-	-	-	-	-	-
Book Expenses	(150)	(33)	(6)	(75)	-	(1)	(5)	(29)	(150)	-	(150)
Interest @ Weighted Cost of Debt	(0)	(0)	(0)	(0)	-	(0)	(0)	(0)	(0)	-	(0)
Production Deduction									-		-
Temporary Sch M Differences									-		-
Permanent M Differences									-		-
State Taxable Income	150	33	6	75	-	1	5	29	150	-	150
State Income Tax	11	3	0	6	-	0	0	2	11	-	11
State Tax Credit									-		-
Net State Income Tax	11	3	0	6	-	0	0	2	11	-	11
Federal Taxable Income	139	31	6	70	-	1	4	27	139	-	139
Fed Tax @ 35%	29	6	1	15	-	0	1	6	29	-	29
Federal Tax Credits									-		-
Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-
Excess Deferred Income Tax Reversal (ARAM)	-	-	-	-	-	-	-	-	-	-	-
Total Income Tax	41	9	2	20	-	0	1	8	41	-	41

Portland General Electric
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Adjustments
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	1/0/1900 A-11 R&D	Prod. Cost	Transmsn. Cost	Dist. Cost	Ancillary Services	Metering Cost	Billing Cost	Other Consumer Cost	PGE Regulated Rev Req	Retail	Check Total
Sales to Consumers									-		-
Other Revenues									-		-
Total Operating Revenues	-	-	-	-	-	-	-	-	-	-	-
Net Variable Power Cost									-		-
Fixed Plant Cost									-		-
Transmission O&M									-		-
Distribution O&M									-		-
Total Fixed O&M	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts								-	-		-
Uncollectibles per Rev Req Model									-		-
Customer Service & Sales									-		-
OPUC Fee									-		
Admin. & General	-								-		-
Other O&M	-	-	-	-	-	-	-	-	-	-	-
Total Operating & Maintenance	-	-	-	-	-	-	-	-	-	-	-
Depreciation & Amortization		-							-		-
Other Taxes									-		-
Franchise Fee									-		-
Income Taxes	-	-	-	-	-	-	-	-	-	-	-
Total Oper. Expenses & Taxes	-	-	-	-	-	-	-	-	-	-	-
Utility Operating Income	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base											
Avg. Gross Plant		-							-		-
Avg. Accum. Deprec.		-							-		-
Avg. Accum. Def Tax		-							-		-
Avg. Accum. Def ITC									-		-
Avg. Net Utility Plant	-	-	-	-	-	-	-	-	-	-	-
Operating Materials & Fuel									-		-
Deferred Programs & Investments									-		-
Misc. Deferred Credits									-		-
Working Cash	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base	-	-	-	-	-	-	-	-	-	-	-
Rate of Return											
Implied Return on Equity											
Income Taxes											
Book Revenues	-	-	-	-	-	-	-	-	-	-	-
Book Expenses	-	-	-	-	-	-	-	-	-	-	-
Interest @ Weighted Cost of Debt	-	-	-	-	-	-	-	-	-	-	-
Production Deduction									-		-
Temporary Sch M Differences									-		-
Permanent M Differences									-		-
State Taxable Income	-	-	-	-	-	-	-	-	-	-	-
State Income Tax	-	-	-	-	-	-	-	-	-	-	-
State Tax Credit									-		-
Net State Income Tax	-	-	-	-	-	-	-	-	-	-	-
Federal Taxable Income	-	-	-	-	-	-	-	-	-	-	-
Fed Tax @ 35%	-	-	-	-	-	-	-	-	-	-	-
Federal Tax Credits									-		-
Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-
Excess Deferred Income Tax Reversal (ARAM)	-	-	-	-	-	-	-	-	-	-	-
Total Income Tax	-	-	-	-	-	-	-	-	-	-	-

Portland General Electric
UE-394, 2022 Test Year
Adjustments
($000)

	1/0/1900 A-18 ADIT-Incentives	Prod. Cost	Transmsn. Cost	Dist. Cost	Ancillary Services	Metering Cost	Billing Cost	Other Consumer Cost	PGE Regulated Rev Req	Retail	Check Total
Sales to Consumers									-		-
Other Revenues									-		-
Total Operating Revenues	-	-	-	-	-	-	-	-	-	-	-
Net Variable Power Cost									-		-
Fixed Plant Cost		-							-		-
Transmission O&M									-		-
Distribution O&M									-		-
Total Fixed O&M	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts									-		-
Uncollectibles per Rev Req Model									-		-
Customer Service & Sales									-		-
OPUC Fee									-		
Admin. & General									-		-
Other O&M	-	-	-	-	-	-	-	-	-	-	-
Total Operating & Maintenance	-	-	-	-	-	-	-	-	-	-	-
Depreciation & Amortization									-		-
Other Taxes									-		-
Franchise Fee									-		-
Income Taxes	32	7	1	16	-	0	1	6	32	-	32
Total Oper. Expenses & Taxes	32	7	1	16	-	0	1	6	32	-	32
Utility Operating Income	(32)	(7)	(1)	(16)	-	(0)	(1)	(6)	(32)	-	(32)
Average Rate Base											
Avg. Gross Plant									-		-
Avg. Accum. Deprec.									-		-
Avg. Accum. Def Tax	5,761	1,271	231	2,894	-	51	186	1,128	5,761	-	5,761
Avg. Accum. Def ITC									-		-
Avg. Net Utility Plant	(5,761)	(1,271)	(231)	(2,894)	-	(51)	(186)	(1,128)	(5,761)	-	(5,761)
Operating Materials & Fuel									-		-
Deferred Programs & Investments									-		-
Misc. Deferred Credits									-		-
Working Cash	1	0	0	1	-	0	0	0	1	-	1
Average Rate Base	(5,760)	(1,270)	(231)	(2,893)	-	(51)	(186)	(1,127)	(5,760)	-	(5,760)
Rate of Return											
Implied Return on Equity											
Income Taxes											
Book Revenues	-	-	-	-	-	-	-	-	-	-	-
Book Expenses	-	-	-	-	-	-	-	-	-	-	-
Interest @ Weighted Cost of Debt	(119)	(26)	(5)	(60)	-	(1)	(4)	(23)	(119)	-	(119)
Production Deduction									-		-
Temporary Sch M Differences									-		-
Permanent M Differences									-		-
State Taxable Income	119	26	5	60	-	1	4	23	119	-	119
State Income Tax	9	2	0	5	-	0	0	2	9	-	9
State Tax Credit									-		-
Net State Income Tax	9	2	0	5	-	0	0	2	9	-	9
Federal Taxable Income	110	24	4	55	-	1	4	21	110	-	110
Fed Tax @ 35%	23	5	1	12	-	0	1	5	23	-	23
Federal Tax Credits									-		-
Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-
Excess Deferred Income Tax Reversal (ARAM)		-	-	-	-	-	-	-	-	-	-
Total Income Tax	32	7	1	16	-	0	1	6	32	-	32

Portland General Electric
UE-394, 2022 Test Year
Adjustments
($000)

	0 Portion of S-23 IOC	Prod. Cost	Transmsn. Cost	Dist. Cost	Ancillary Services	Metering Cost	Billing Cost	Other Consumer Cost	PGE Regulated Rev Req	Retail	Check Total
Sales to Consumers									-		-
Other Revenues									-		-
Total Operating Revenues	-	-	-	-	-	-	-	-	-	-	-
Net Variable Power Cost									-		-
Fixed Plant Cost		-							-		-
Transmission O&M									-		-
Distribution O&M									-		-
Total Fixed O&M	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts									-		-
Uncollectibles per Rev Req Model									-		-
Customer Service & Sales									-		-
OPUC Fee									-		
Admin. & General									-		-
Other O&M	-	-	-	-	-	-	-	-	-	-	-
Total Operating & Maintenance	-	-	-	-	-	-	-	-	-	-	-
Depreciation & Amortization									-		-
Other Taxes									-		-
Franchise Fee									-		-
Income Taxes	50	16	12	19	-	0	0	3	50	-	50
Total Oper. Expenses & Taxes	50	16	12	19	-	0	0	3	50	-	50
Utility Operating Income	(50)	(16)	(12)	(19)	-	(0)	(0)	(3)	(50)	-	(50)
Average Rate Base											
Avg. Gross Plant	(9,000)	(2,847)	(2,117)	(3,447)	-	(16)	(58)	(516)	(9,000)		(9,000)
Avg. Accum. Deprec.		-	-	-	-	-	-	-	-	-	-
Avg. Accum. Def Tax									-		-
Avg. Accum. Def ITC									-		-
Avg. Net Utility Plant	(9,000)	(2,847)	(2,117)	(3,447)	-	(16)	(58)	(516)	(9,000)	-	(9,000)
Operating Materials & Fuel									-		-
Deferred Programs & Investments									-		-
Misc. Deferred Credits									-		-
Working Cash	2	1	0	1	-	0	0	0	2	-	2
Average Rate Base	(8,998)	(2,846)	(2,116)	(3,446)	-	(16)	(58)	(516)	(8,998)	-	(8,998)
Rate of Return											
Implied Return on Equity											
Income Taxes											
Book Revenues	-	-	-	-	-	-	-	-	-	-	-
Book Expenses	-	-	-	-	-	-	-	-	-	-	-
Interest @ Weighted Cost of Debt	(186)	(59)	(44)	(71)	-	(0)	(1)	(11)	(186)	-	(186)
Production Deduction									-		-
Temporary Sch M Differences									-		-
Permanent M Differences									-		-
State Taxable Income	186	59	44	71	-	0	1	11	186	-	186
State Income Tax	14	4	3	5	-	0	0	1	14	-	14
State Tax Credit									-		-
Net State Income Tax	14	4	3	5	-	0	0	1	14	-	14
Federal Taxable Income	171	54	40	66	-	0	1	10	171	-	171
Fed Tax @ 35%	36	11	8	14	-	0	0	2	36	-	36
Federal Tax Credits									-		-
Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-
Excess Deferred Income Tax Reversal (ARAM)	-	-	-	-	-	-	-	-	-	-	-
Total Income Tax	50	16	12	19	-	0	0	3	50	-	50

Portland General Electric
UE-394, 2022 Test Year
Adjustments
($000)

	1/0/1900 A-26 Trojan Sch. 136	Prod. Cost	Transmsn. Cost	Dist. Cost	Ancillary Services	Metering Cost	Billing Cost	Other Consumer Cost	PGE Regulated Rev Req	Retail	Check Total
Sales to Consumers									-		-
Other Revenues									-		-
Total Operating Revenues	-	-	-	-	-	-	-	-	-	-	-
Net Variable Power Cost									-		-
Fixed Plant Cost									-		-
Transmission O&M									-		-
Distribution O&M	-								-		-
Total Fixed O&M	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts									-		-
Uncollectibles per Rev Req Model									-		-
Customer Service & Sales								-	-		-
OPUC Fee									-		
Admin. & General									-		-
Other O&M	-	-	-	-	-	-	-	-	-	-	-
Total Operating & Maintenance	-	-	-	-	-	-	-	-	-	-	-
Depreciation & Amortization		-	-	-	-	-	-	-	-	-	-
Other Taxes									-		-
Franchise Fee									-		-
Income Taxes	-	-	-	-	-	-	-	-	-	-	-
Total Oper. Expenses & Taxes	-	-	-	-	-	-	-	-	-	-	-
Utility Operating Income	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base											
Avg. Gross Plant									-		-
Avg. Accum. Deprec.									-		-
Avg. Accum. Def Tax									-		-
Avg. Accum. Def ITC									-		-
Avg. Net Utility Plant	-	-	-	-	-	-	-	-	-	-	-
Operating Materials & Fuel									-		-
Deferred Programs & Investments									-		-
Misc. Deferred Credits									-		-
Working Cash	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base	-	-	-	-	-	-	-	-	-	-	-
Rate of Return											
Implied Return on Equity											
Income Taxes											
Book Revenues	-	-	-	-	-	-	-	-	-	-	-
Book Expenses	-	-	-	-	-	-	-	-	-	-	-
Interest @ Weighted Cost of Debt	-	-	-	-	-	-	-	-	-	-	-
Production Deduction									-		-
Temporary Sch M Differences									-		-
Permanent M Differences									-		-
State Taxable Income	-	-	-	-	-	-	-	-	-	-	-
State Income Tax	-	-	-	-	-	-	-	-	-	-	-
State Tax Credit									-		-
Net State Income Tax	-	-	-	-	-	-	-	-	-	-	-
Federal Taxable Income	-	-	-	-	-	-	-	-	-	-	-
Fed Tax @ 35%	-	-	-	-	-	-	-	-	-	-	-
Federal Tax Credits									-		-
Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-
Excess Deferred Income Tax Reversal (ARAM)	-	-	-	-	-	-	-	-	-	-	-
Total Income Tax	-	-	-	-	-	-	-	-	-	-	-

Portland General Electric
UE-394, 2022 Test Year
Adjustments
($000)

	0 C-4 CampgoundRevenue	Prod. Cost	Transmsn. Cost	Dist. Cost	Ancillary Services	Metering Cost	Billing Cost	Other Consumer Cost	PGE Regulated Rev Req	Retail	Check Total
Sales to Consumers									-		-
Other Revenues	165	165							165		165
Total Operating Revenues	165	165	-	-	-	-	-	-	165	-	165
Net Variable Power Cost									-		-
Fixed Plant Cost									-		-
Transmission O&M									-		-
Distribution O&M				-					-		-
Total Fixed O&M	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts									-		-
Uncollectibles per Rev Req Model									-		-
Customer Service & Sales								-	-		-
OPUC Fee									-		
Admin. & General		-	-	-	-	-	-	-	-	-	-
Other O&M	-	-	-	-	-	-	-	-	-	-	-
Total Operating & Maintenance	-	-	-	-	-	-	-	-	-	-	-
Depreciation & Amortization									-		-
Other Taxes									-		-
Franchise Fee									-		-
Income Taxes	45	45	-	-	-	-	-	-	45	-	45
Total Oper. Expenses & Taxes	45	45	-	-	-	-	-	-	45	-	45
Utility Operating Income	120	120	-	-	-	-	-	-	120	-	120
Average Rate Base											
Avg. Gross Plant									-		-
Avg. Accum. Deprec.									-		-
Avg. Accum. Def Tax									-		-
Avg. Accum. Def ITC									-		-
Avg. Net Utility Plant	-	-	-	-	-	-	-	-	-	-	-
Operating Materials & Fuel									-		-
Deferred Programs & Investments									-		-
Misc. Deferred Credits									-		-
Working Cash	2	2	-	-	-	-	-	-	2	-	2
Average Rate Base	2	2	-	-	-	-	-	-	2	-	2
Rate of Return											
Implied Return on Equity											
Income Taxes											
Book Revenues	165	165	-	-	-	-	-	-	165	-	165
Book Expenses	-	-	-	-	-	-	-	-	-	-	-
Interest @ Weighted Cost of Debt	0	0	-	-	-	-	-	-	0	-	0
Production Deduction									-		-
Temporary Sch M Differences									-		-
Permanent M Differences									-		-
State Taxable Income	165	165	-	-	-	-	-	-	165	-	165
State Income Tax	13	13	-	-	-	-	-	-	13	-	13
State Tax Credit									-		-
Net State Income Tax	13	13	-	-	-	-	-	-	13	-	13
Federal Taxable Income	152	152	-	-	-	-	-	-	152	-	152
Fed Tax @ 35%	32	32	-	-	-	-	-	-	32	-	32
Federal Tax Credits									-		-
Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-
Excess Deferred Income Tax Reversal (ARAM)	-	-	-	-	-	-	-	-	-	-	-
Total Income Tax	45	45	-	-	-	-	-	-	45	-	45

Portland General Electric
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Adjustments
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	0 S-8, S-9, S-10 Bundle Bundled Adjjustmen	Prod. Cost	Transmsn. Cost	Dist. Cost	Ancillary Services	Metering Cost	Billing Cost	Other Consumer Cost	PGE Regulated Rev Req	Retail	Check Total
Sales to Consumers									-		-
Other Revenues									-		-
Total Operating Revenues	-	-	-	-	-	-	-	-	-	-	-
Net Variable Power Cost									-		-
Fixed Plant Cost									-		-
Transmission O&M									-		-
Distribution O&M									-		-
Total Fixed O&M	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts									-		-
Uncollectibles per Rev Req Model									-		-
Customer Service & Sales									-		-
OPUC Fee									-		
Admin. & General	(700)	(154)	(28)	(352)	-	(6)	(23)	(137)	(700)		(700)
Other O&M	(700)	(154)	(28)	(352)	-	(6)	(23)	(137)	(700)	-	(700)
Total Operating & Maintenance	(700)	(154)	(28)	(352)	-	(6)	(23)	(137)	(700)	-	(700)
Depreciation & Amortization									-		-
Other Taxes									-		-
Franchise Fee									-		-
Income Taxes	189	42	8	95	-	2	6	37	189	-	189
Total Oper. Expenses & Taxes	(511)	(113)	(21)	(257)	-	(5)	(17)	(100)	(511)	-	(511)
Utility Operating Income	511	113	21	257	-	5	17	100	511	-	511
Average Rate Base											
Avg. Gross Plant									-		-
Avg. Accum. Deprec.									-		-
Avg. Accum. Def Tax									-		-
Avg. Accum. Def ITC									-		-
Avg. Net Utility Plant	-	-	-	-	-	-	-	-	-	-	-
Operating Materials & Fuel									-		-
Deferred Programs & Investments									-		-
Misc. Deferred Credits									-		-
Working Cash	(20)	(4)	(1)	(10)	-	(0)	(1)	(4)	(20)	-	(20)
Average Rate Base	(20)	(4)	(1)	(10)	-	(0)	(1)	(4)	(20)	-	(20)
Rate of Return											
Implied Return on Equity											
Income Taxes											
Book Revenues	-	-	-	-	-	-	-	-	-	-	-
Book Expenses	(700)	(154)	(28)	(352)	-	(6)	(23)	(137)	(700)	-	(700)
Interest @ Weighted Cost of Debt	(0)	(0)	(0)	(0)	-	(0)	(0)	(0)	(0)	-	(0)
Production Deduction									-		-
Temporary Sch M Differences									-		-
Permanent M Differences									-		-
State Taxable Income	700	154	28	352	-	6	23	137	700	-	700
State Income Tax	53	12	2	27	-	0	2	10	53	-	53
State Tax Credit									-		-
Net State Income Tax	53	12	2	27	-	0	2	10	53	-	53
Federal Taxable Income	647	143	26	325	-	6	21	127	647	-	647
Fed Tax @ 35%	136	30	5	68	-	1	4	27	136	-	136
Federal Tax Credits									-		-
Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-
Excess Deferred Income Tax Reversal (ARAM)	-	-	-	-	-	-	-	-	-	-	-
Total Income Tax	189	42	8	95	-	2	6	37	189	-	189

Portland General Electric
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	0 S-22, A-20, A-23 Bund Bundled Adjjustmen	Prod. Cost	Transmsn. Cost	Dist. Cost	Ancillary Services	Metering Cost	Billing Cost	Other Consumer Cost	PGE Regulated Rev Req	Retail	Check Total
Sales to Consumers									-		-
Other Revenues									-		-
Total Operating Revenues	-	-	-	-	-	-	-	-	-	-	-
Net Variable Power Cost									-		-
Fixed Plant Cost									-		-
Transmission O&M									-		-
Distribution O&M									-		-
Total Fixed O&M	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts									-		-
Uncollectibles per Rev Req Model									-		-
Customer Service & Sales									-		-
OPUC Fee									-		
Admin. & General									-		-
Other O&M	-	-	-	-	-	-	-	-	-	-	-
Total Operating & Maintenance	-	-	-	-	-	-	-	-	-	-	-
Depreciation & Amortization									-		-
Other Taxes									-		-
Franchise Fee									-		-
Income Taxes	58	58	-	-	-	-	-	-	58	-	58
Total Oper. Expenses & Taxes	58	58	-	-	-	-	-	-	58	-	58
Utility Operating Income	(58)	(58)	-	-	-	-	-	-	(58)	-	(58)
Average Rate Base											
Avg. Gross Plant	(10,500)	(10,500)							(10,500)		(10,500)
Avg. Accum. Deprec.									-		-
Avg. Accum. Def Tax		-	-	-	-	-	-	-	-		-
Avg. Accum. Def ITC									-		-
Avg. Net Utility Plant	(10,500)	(10,500)	-	-	-	-	-	-	(10,500)	-	(10,500)
Operating Materials & Fuel									-		-
Deferred Programs & Investments									-		-
Misc. Deferred Credits									-		-
Working Cash	2	2	-	-	-	-	-	-	2	-	2
Average Rate Base	(10,498)	(10,498)	-	-	-	-	-	-	(10,498)	-	(10,498)
Rate of Return											
Implied Return on Equity											
Income Taxes											
Book Revenues	-	-	-	-	-	-	-	-	-	-	-
Book Expenses	-	-	-	-	-	-	-	-	-	-	-
Interest @ Weighted Cost of Debt	(217)	(217)	-	-	-	-	-	-	(217)	-	(217)
Production Deduction									-		-
Temporary Sch M Differences									-		-
Permanent M Differences									-		-
State Taxable Income	217	217	-	-	-	-	-	-	217	-	217
State Income Tax	16	16	-	-	-	-	-	-	16	-	16
State Tax Credit									-		-
Net State Income Tax	16	16	-	-	-	-	-	-	16	-	16
Federal Taxable Income	200	200	-	-	-	-	-	-	200	-	200
Fed Tax @ 35%	42	42	-	-	-	-	-	-	42	-	42
Federal Tax Credits									-		-
Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-
Excess Deferred Income Tax Reversal (ARAM)	-	-	-	-	-	-	-	-	-	-	-
Total Income Tax	58	58	-	-	-	-	-	-	58	-	58

Portland General Electric
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Adjustments
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	0 12/13/21 Proposal Remove Faraday	Prod. Cost	Transmsn. Cost	Dist. Cost	Ancillary Services	Metering Cost	Billing Cost	Other Consumer Cost	PGE Regulated Rev Req	Retail	Check Total
Sales to Consumers									-		-
Other Revenues									-		-
Total Operating Revenues	-	-	-	-	-	-	-	-	-	-	-
Net Variable Power Cost									-		-
Fixed Plant Cost									-		-
Transmission O&M									-		-
Distribution O&M									-		-
Total Fixed O&M	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts									-		-
Uncollectibles per Rev Req Model									-		-
Customer Service & Sales									-		-
OPUC Fee									-		
Admin. & General									-		-
Other O&M	-	-	-	-	-	-	-	-	-	-	-
Total Operating & Maintenance	-	-	-	-	-	-	-	-	-	-	-
Depreciation & Amortization	(5,121)	(5,121)							(5,121)		(5,121)
Other Taxes	(1,708)	(1,708)							(1,708)		(1,708)
Franchise Fee									-		-
Income Taxes	2,479	2,479	-	-	-	-	-	-	2,479	-	2,479
Total Oper. Expenses & Taxes	(4,351)	(4,351)	-	-	-	-	-	-	(4,351)	-	(4,351)
Utility Operating Income	4,351	4,351	-	-	-	-	-	-	4,351	-	4,351
Average Rate Base											
Avg. Gross Plant	(119,385)	(119,385)							(119,385)		(119,385)
Avg. Accum. Deprec.	(5,121)	(5,121)							(5,121)		(5,121)
Avg. Accum. Def Tax	(381)	(381)							(381)		(381)
Avg. Accum. Def ITC									-		-
Avg. Net Utility Plant	(113,882)	(113,882)	-	-	-	-	-	-	(113,882)	-	(113,882)
Operating Materials & Fuel									-		-
Deferred Programs & Investments									-		-
Misc. Deferred Credits		-							-		-
Working Cash	(169)	(169)	-	-	-	-	-	-	(169)	-	(169)
Average Rate Base	(114,052)	(114,052)	-	-	-	-	-	-	(114,052)	-	(114,052)
Rate of Return											
Implied Return on Equity											
Income Taxes											
Book Revenues	-	-	-	-	-	-	-	-	-	-	-
Book Expenses	(6,830)	(6,830)	-	-	-	-	-	-	(6,830)	-	(6,830)
Interest @ Weighted Cost of Debt	(2,352)	(2,352)	-	-	-	-	-	-	(2,352)	-	(2,352)
Production Deduction									-		-
Temporary Sch M Differences									-		-
Permanent M Differences									-		-
State Taxable Income	9,182	9,182	-	-	-	-	-	-	9,182	-	9,182
State Income Tax	697	697	-	-	-	-	-	-	697	-	697
State Tax Credit									-		-
Net State Income Tax	697	697	-	-	-	-	-	-	697	-	697
Federal Taxable Income	8,485	8,485	-	-	-	-	-	-	8,485	-	8,485
Fed Tax @ 35%	1,782	1,782	-	-	-	-	-	-	1,782	-	1,782
Federal Tax Credits									-		-
Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-
Excess Deferred Income Tax Reversal (ARAM)	-	-	-	-	-	-	-	-	-	-	-
Total Income Tax	2,479	2,479	-	-	-	-	-	-	2,479	-	2,479

Portland General Electric
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Adjustments
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	Global to $10MM	Prod. Cost	Transmsn. Cost	Dist. Cost	Ancillary Services	Metering Cost	Billing Cost	Other Consumer Cost	PGE Regulated Rev Req	Retail	Check Total
Sales to Consumers									-		-
Other Revenues									-		-
Total Operating Revenues	-	-	-	-	-	-	-	-	-	-	-
Net Variable Power Cost									-		-
Fixed Plant Cost									-		-
Transmission O&M									-		-
Distribution O&M				-					-		-
Total Fixed O&M	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts									-		-
Uncollectibles per Rev Req Model									-		-
Customer Service & Sales									-		-
OPUC Fee									-		
Admin. & General	(2,202)	(486)	(88)	(1,106)	-	(20)	(71)	(431)	(2,202)	-	(2,202)
Other O&M	(2,202)	(486)	(88)	(1,106)	-	(20)	(71)	(431)	(2,202)	-	(2,202)
Total Operating & Maintenance	(2,202)	(486)	(88)	(1,106)	-	(20)	(71)	(431)	(2,202)	-	(2,202)
Depreciation & Amortization		-	-	-	-	-	-	-	-		-
Other Taxes		-	-	-	-	-	-	-	-		-
Franchise Fee									-		-
Income Taxes	678	131	24	382	-	5	19	116	678	-	678
Total Oper. Expenses & Taxes	(1,524)	(354)	(65)	(724)	-	(14)	(52)	(315)	(1,524)	-	(1,524)
Utility Operating Income	1,524	354	65	724	-	14	52	315	1,524	-	1,524
Average Rate Base											
Avg. Gross Plant	(15,000)			(15,000)					(15,000)		(15,000)
Avg. Accum. Deprec.									-		-
Avg. Accum. Def Tax									-		-
Avg. Accum. Def ITC									-		-
Avg. Net Utility Plant	(15,000)	-	-	(15,000)	-	-	-	-	(15,000)	-	(15,000)
Operating Materials & Fuel									-		-
Deferred Programs & Investments									-		-
Misc. Deferred Credits									-		-
Working Cash	(59)	(14)	(3)	(28)	-	(1)	(2)	(12)	(59)	-	(59)
Average Rate Base	(15,059)	(14)	(3)	(15,028)	-	(1)	(2)	(12)	(15,059)	-	(15,059)
Rate of Return											
Implied Return on Equity											
Income Taxes											
Book Revenues	-	-	-	-	-	-	-	-	-	-	-
Book Expenses	(2,202)	(486)	(88)	(1,106)	-	(20)	(71)	(431)	(2,202)	-	(2,202)
Interest @ Weighted Cost of Debt	(311)	(0)	(0)	(310)	-	(0)	(0)	(0)	(311)	-	(311)
Production Deduction									-		-
Temporary Sch M Differences									-		-
Permanent M Differences									-		-
State Taxable Income	2,513	486	88	1,416	-	20	71	431	2,513	-	2,513
State Income Tax	191	37	7	108	-	1	5	33	191	-	191
State Tax Credit									-		-
Net State Income Tax	191	37	7	108	-	1	5	33	191	-	191
Federal Taxable Income	2,322	449	82	1,309	-	18	66	398	2,322	-	2,322
Fed Tax @ 35%	488	94	17	275	-	4	14	84	488	-	488
Federal Tax Credits									-		-
Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-
Excess Deferred Income Tax Reversal (ARAM)	-	-	-	-	-	-	-	-	-	-	-
Total Income Tax	678	131	24	382	-	5	19	116	678	-	678

Portland General Electric
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Adjustments
($000)

	Adjust Depreciation to UM 2152	Prod. Cost	Transmsn. Cost	Dist. Cost	Ancillary Services	Metering Cost	Billing Cost	Other Consumer Cost	PGE Regulated Rev Req	Retail	Check Total
Sales to Consumers									-		-
Other Revenues									-		-
Total Operating Revenues	-	-	-	-	-	-	-	-	-	-	-
Net Variable Power Cost									-		-
Fixed Plant Cost									-		-
Transmission O&M									-		-
Distribution O&M									-		-
Total Fixed O&M	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts									-		-
Uncollectibles per Rev Req Model									-		-
Customer Service & Sales									-		-
OPUC Fee									-		
Admin. & General		-	-	-	-	-	-	-	-		-
Other O&M	-	-	-	-	-	-	-	-	-	-	-
Total Operating & Maintenance	-	-	-	-	-	-	-	-	-	-	-
Depreciation & Amortization	387	17,279	(830)	(15,054)	-	(38)	(137)	(827)	394	(7)	387
Other Taxes									-		-
Franchise Fee									-		-
Income Taxes	289	(4,161)	233	3,950	-	10	36	219	288	2	289
Total Oper. Expenses & Taxes	676	13,119	(597)	(11,104)	-	(28)	(100)	(608)	681	(5)	676
Utility Operating Income	(676)	(13,119)	597	11,104	-	28	100	608	(681)	5	(676)
Average Rate Base											
Avg. Gross Plant									-		-
Avg. Accum. Deprec.	197	17,294	(1,119)	(15,084)	-	(33)	(121)	(733)	203	(6)	197
Avg. Accum. Def Tax	8,694	1,179	1,082	5,934	-	46	91	361	8,692	2	8,694
Avg. Accum. Def ITC									-		-
Avg. Net Utility Plant	(8,892)	(18,473)	37	9,150	-	(12)	30	373	(8,895)	4	(8,892)
Operating Materials & Fuel									-		-
Deferred Programs & Investments									-		-
Misc. Deferred Credits									-		-
Working Cash	26	510	(23)	(432)	-	(1)	(4)	(24)	26	(0)	26
Average Rate Base	(8,865)	(17,963)	14	8,718	-	(13)	26	349	(8,869)	3	(8,865)
Rate of Return											
Implied Return on Equity											
Income Taxes											
Book Revenues	-	-	-	-	-	-	-	-	-	-	-
Book Expenses	387	17,279	(830)	(15,054)	-	(38)	(137)	(827)	394	(7)	387
Interest @ Weighted Cost of Debt	(183)	(370)	0	180	-	(0)	1	7	(183)	0	(183)
Production Deduction									-		-
Temporary Sch M Differences	(14,741)	(2,333)	(1,130)	(10,517)	-	(28)	(103)	(624)	(14,736)	(5)	(14,741)
Permanent M Differences	(1,276)	(1,499)	(33)	245	-	0	2	10	(1,276)	0	(1,276)
State Taxable Income	15,813	(13,076)	1,992	25,147	-	66	237	1,434	15,801	12	15,813
State Income Tax	1,201	(993)	151	1,910	-	5	18	109	1,200	1	1,201
State Tax Credit									-		-
Net State Income Tax	1,201	(993)	151	1,910	-	5	18	109	1,200	1	1,201
Federal Taxable Income	14,612	(12,083)	1,841	23,237	-	61	219	1,325	14,601	11	14,612
Fed Tax @ 35%	3,068	(2,537)	387	4,880	-	13	46	278	3,066	2	3,068
Federal Tax Credits									-		-
Deferred Taxes	(3,980)	(630)	(305)	(2,840)	-	(8)	(28)	(168)	(3,979)	(1)	(3,980)
Excess Deferred Income Tax Reversal (ARAM)	-	-	-	-	-	-	-	-	-	-	-
Total Income Tax	289	(4,161)	233	3,950	-	10	36	219	288	2	289

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Adjustments
($000)

	0 0 Blank-18	Prod. Cost	Transmsn. Cost	Dist. Cost	Ancillary Services	Metering Cost	Billing Cost	Other Consumer Cost	PGE Regulated Rev Req	Retail	Check Total
Sales to Consumers									-		-
Other Revenues									-		-
Total Operating Revenues	-	-	-	-	-	-	-	-	-	-	-
Net Variable Power Cost									-		-
Fixed Plant Cost									-		-
Transmission O&M									-		-
Distribution O&M									-		-
Total Fixed O&M	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts									-		-
Uncollectibles per Rev Req Model									-		-
Customer Service & Sales									-		-
OPUC Fee									-		
Admin. & General		-	-	-	-	-	-	-	-		-
Other O&M	-	-	-	-	-	-	-	-	-	-	-
Total Operating & Maintenance	-	-	-	-	-	-	-	-	-	-	-
Depreciation & Amortization		-	-	-	-	-	-	-	-	-	-
Other Taxes									-		-
Franchise Fee									-		-
Income Taxes	-	-	-	-	-	-	-	-	-	-	-
Total Oper. Expenses & Taxes	-	-	-	-	-	-	-	-	-	-	-
Utility Operating Income	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base											
Avg. Gross Plant									-		-
Avg. Accum. Deprec.									-		-
Avg. Accum. Def Tax									-		-
Avg. Accum. Def ITC									-		-
Avg. Net Utility Plant	-	-	-	-	-	-	-	-	-	-	-
Operating Materials & Fuel									-		-
Deferred Programs & Investments									-		-
Misc. Deferred Credits									-		-
Working Cash	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base	-	-	-	-	-	-	-	-	-	-	-
Rate of Return											
Implied Return on Equity											
Income Taxes											
Book Revenues	-	-	-	-	-	-	-	-	-	-	-
Book Expenses	-	-	-	-	-	-	-	-	-	-	-
Interest @ Weighted Cost of Debt	-	-	-	-	-	-	-	-	-	-	-
Production Deduction									-		-
Temporary Sch M Differences									-		-
Permanent M Differences									-		-
State Taxable Income	-	-	-	-	-	-	-	-	-	-	-
State Income Tax	-	-	-	-	-	-	-	-	-	-	-
State Tax Credit									-		-
Net State Income Tax	-	-	-	-	-	-	-	-	-	-	-
Federal Taxable Income	-	-	-	-	-	-	-	-	-	-	-
Fed Tax @ 35%	-	-	-	-	-	-	-	-	-	-	-
Federal Tax Credits									-		-
Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-
Excess Deferred Income Tax Reversal (ARAM)	-	-	-	-	-	-	-	-	-	-	-
Total Income Tax	-	-	-	-	-	-	-	-	-	-	-

Portland General Electric
UE-394, 2022 Test Year
Adjustments
($000)

	0 0 Blank-19	Prod. Cost	Transmsn. Cost	Dist. Cost	Ancillary Services	Metering Cost	Billing Cost	Other Consumer Cost	PGE Regulated Rev Req	Retail	Check Total
Sales to Consumers									-		-
Other Revenues									-		-
Total Operating Revenues	-	-	-	-	-	-	-	-	-	-	-
Net Variable Power Cost									-		-
Fixed Plant Cost									-		-
Transmission O&M									-		-
Distribution O&M									-		-
Total Fixed O&M	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts									-		-
Uncollectibles per Rev Req Model									-		-
Customer Service & Sales									-		-
OPUC Fee									-		
Admin. & General		-	-	-	-	-	-	-	-	-	-
Other O&M	-	-	-	-	-	-	-	-	-	-	-
Total Operating & Maintenance	-	-	-	-	-	-	-	-	-	-	-
Depreciation & Amortization									-		-
Other Taxes									-		-
Franchise Fee									-		-
Income Taxes	-	-	-	-	-	-	-	-	-	-	-
Total Oper. Expenses & Taxes	-	-	-	-	-	-	-	-	-	-	-
Utility Operating Income	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base											
Avg. Gross Plant		-	-	-	-	-	-	-	-		-
Avg. Accum. Deprec.									-		-
Avg. Accum. Def Tax									-		-
Avg. Accum. Def ITC									-		-
Avg. Net Utility Plant	-	-	-	-	-	-	-	-	-	-	-
Operating Materials & Fuel									-		-
Deferred Programs & Investments									-		-
Misc. Deferred Credits									-		-
Working Cash	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base	-	-	-	-	-	-	-	-	-	-	-
Rate of Return											
Implied Return on Equity											
Income Taxes											
Book Revenues	-	-	-	-	-	-	-	-	-	-	-
Book Expenses	-	-	-	-	-	-	-	-	-	-	-
Interest @ Weighted Cost of Debt	-	-	-	-	-	-	-	-	-	-	-
Production Deduction									-		-
Temporary Sch M Differences									-		-
Permanent M Differences									-		-
State Taxable Income	-	-	-	-	-	-	-	-	-	-	-
State Income Tax	-	-	-	-	-	-	-	-	-	-	-
State Tax Credit									-		-
Net State Income Tax	-	-	-	-	-	-	-	-	-	-	-
Federal Taxable Income	-	-	-	-	-	-	-	-	-	-	-
Fed Tax @ 35%	-	-	-	-	-	-	-	-	-	-	-
Federal Tax Credits									-		-
Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-
Excess Deferred Income Tax Reversal (ARAM)	-	-	-	-	-	-	-	-	-	-	-
Total Income Tax	-	-	-	-	-	-	-	-	-	-	-

Portland General Electric
UE-394, 2022 Test Year
Adjustments
($000)

	0 0 Blank-20	Prod. Cost	Transmsn. Cost	Dist. Cost	Ancillary Services	Metering Cost	Billing Cost	Other Consumer Cost	PGE Regulated Rev Req	Retail	Check Total
Sales to Consumers									-		-
Other Revenues									-		-
Total Operating Revenues	-	-	-	-	-	-	-	-	-	-	-
Net Variable Power Cost									-		-
Fixed Plant Cost									-		-
Transmission O&M									-		-
Distribution O&M									-		-
Total Fixed O&M	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts									-		-
Uncollectibles per Rev Req Model									-		-
Customer Service & Sales									-		-
OPUC Fee									-		
Admin. & General									-		-
Other O&M	-	-	-	-	-	-	-	-	-	-	-
Total Operating & Maintenance	-	-	-	-	-	-	-	-	-	-	-
Depreciation & Amortization									-		-
Other Taxes									-		-
Franchise Fee									-		-
Income Taxes	-	-	-	-	-	-	-	-	-	-	-
Total Oper. Expenses & Taxes	-	-	-	-	-	-	-	-	-	-	-
Utility Operating Income	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base											
Avg. Gross Plant									-		-
Avg. Accum. Deprec.									-		-
Avg. Accum. Def Tax		-							-		-
Avg. Accum. Def ITC									-		-
Avg. Net Utility Plant	-	-	-	-	-	-	-	-	-	-	-
Operating Materials & Fuel									-		-
Deferred Programs & Investments									-		-
Misc. Deferred Credits									-		-
Working Cash	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base	-	-	-	-	-	-	-	-	-	-	-
Rate of Return											
Implied Return on Equity											
Income Taxes											
Book Revenues	-	-	-	-	-	-	-	-	-	-	-
Book Expenses	-	-	-	-	-	-	-	-	-	-	-
Interest @ Weighted Cost of Debt	-	-	-	-	-	-	-	-	-	-	-
Production Deduction									-		-
Temporary Sch M Differences									-		-
Permanent M Differences									-		-
State Taxable Income	-	-	-	-	-	-	-	-	-	-	-
State Income Tax	-	-	-	-	-	-	-	-	-	-	-
State Tax Credit		-	-	-	-	-	-	-	-		-
Net State Income Tax	-	-	-	-	-	-	-	-	-	-	-
Federal Taxable Income	-	-	-	-	-	-	-	-	-	-	-
Fed Tax @ 35%	-	-	-	-	-	-	-	-	-	-	-
Federal Tax Credits									-		-
Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-
Excess Deferred Income Tax Reversal (ARAM)	-	-	-	-	-	-	-	-	-	-	-
Total Income Tax	-	-	-	-	-	-	-	-	-	-	-

Portland General Electric
UE-394, 2022 Test Year
Adjustments
($000)

	0 0 Blank 21	Prod. Cost	Transmsn. Cost	Dist. Cost	Ancillary Services	Metering Cost	Billing Cost	Other Consumer Cost	PGE Regulated Rev Req	Retail	Check Total
Sales to Consumers									-		-
Other Revenues									-		-
Total Operating Revenues	-	-	-	-	-	-	-	-	-	-	-
Net Variable Power Cost									-		-
Fixed Plant Cost									-		-
Transmission O&M									-		-
Distribution O&M									-		-
Total Fixed O&M	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts									-		-
Uncollectibles per Rev Req Model									-		-
Customer Service & Sales									-		-
OPUC Fee									-		
Admin. & General									-		-
Other O&M	-	-	-	-	-	-	-	-	-	-	-
Total Operating & Maintenance	-	-	-	-	-	-	-	-	-	-	-
Depreciation & Amortization									-		-
Other Taxes									-		-
Franchise Fee									-		-
Income Taxes	-	-	-	-	-	-	-	-	-	-	-
Total Oper. Expenses & Taxes	-	-	-	-	-	-	-	-	-	-	-
Utility Operating Income	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base											
Avg. Gross Plant									-		-
Avg. Accum. Deprec.									-		-
Avg. Accum. Def Tax		-	-	-	-	-	-	-	-	-	-
Avg. Accum. Def ITC									-		-
Avg. Net Utility Plant	-	-	-	-	-	-	-	-	-	-	-
Operating Materials & Fuel									-		-
Deferred Programs & Investments									-		-
Misc. Deferred Credits									-		-
Working Cash	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base	-	-	-	-	-	-	-	-	-	-	-
Rate of Return											
Implied Return on Equity											
Income Taxes											
Book Revenues	-	-	-	-	-	-	-	-	-	-	-
Book Expenses	-	-	-	-	-	-	-	-	-	-	-
Interest @ Weighted Cost of Debt	-	-	-	-	-	-	-	-	-	-	-
Production Deduction									-		-
Temporary Sch M Differences									-		-
Permanent M Differences									-		-
State Taxable Income	-	-	-	-	-	-	-	-	-	-	-
State Income Tax	-	-	-	-	-	-	-	-	-	-	-
State Tax Credit									-		-
Net State Income Tax	-	-	-	-	-	-	-	-	-	-	-
Federal Taxable Income	-	-	-	-	-	-	-	-	-	-	-
Fed Tax @ 35%	-	-	-	-	-	-	-	-	-	-	-
Federal Tax Credits									-		-
Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-
Excess Deferred Income Tax Reversal (ARAM)	-	-	-	-	-	-	-	-	-	-	-
Total Income Tax	-	-	-	-	-	-	-	-	-	-	-

Portland General Electric
UE-394, 2022 Test Year
Adjustments
($000)

	0 0 Blank 22	Prod. Cost	Transmsn. Cost	Dist. Cost	Ancillary Services	Metering Cost	Billing Cost	Other Consumer Cost	PGE Regulated Rev Req	Retail	Check Total
Sales to Consumers									-		-
Other Revenues									-		-
Total Operating Revenues	-	-	-	-	-	-	-	-	-	-	-
Net Variable Power Cost									-		-
Fixed Plant Cost									-		-
Transmission O&M									-		-
Distribution O&M									-		-
Total Fixed O&M	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts									-		-
Uncollectibles per Rev Req Model									-		-
Customer Service & Sales									-		-
OPUC Fee									-		
Admin. & General		-	-	-	-	-	-	-	-		-
Other O&M	-	-	-	-	-	-	-	-	-	-	-
Total Operating & Maintenance	-	-	-	-	-	-	-	-	-	-	-
Depreciation & Amortization									-		-
Other Taxes									-		-
Franchise Fee									-		-
Income Taxes	-	-	-	-	-	-	-	-	-	-	-
Total Oper. Expenses & Taxes	-	-	-	-	-	-	-	-	-	-	-
Utility Operating Income	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base											
Avg. Gross Plant		-	-	-	-	-	-	-	-		-
Avg. Accum. Deprec.									-		-
Avg. Accum. Def Tax		-							-		-
Avg. Accum. Def ITC									-		-
Avg. Net Utility Plant	-	-	-	-	-	-	-	-	-	-	-
Operating Materials & Fuel									-		-
Deferred Programs & Investments									-		-
Misc. Deferred Credits									-		-
Working Cash	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base	-	-	-	-	-	-	-	-	-	-	-
Rate of Return											
Implied Return on Equity											
Income Taxes											
Book Revenues	-	-	-	-	-	-	-	-	-	-	-
Book Expenses	-	-	-	-	-	-	-	-	-	-	-
Interest @ Weighted Cost of Debt	-	-	-	-	-	-	-	-	-	-	-
Production Deduction									-		-
Temporary Sch M Differences									-		-
Permanent M Differences									-		-
State Taxable Income	-	-	-	-	-	-	-	-	-	-	-
State Income Tax	-	-	-	-	-	-	-	-	-	-	-
State Tax Credit									-		-
Net State Income Tax	-	-	-	-	-	-	-	-	-	-	-
Federal Taxable Income	-	-	-	-	-	-	-	-	-	-	-
Fed Tax @ 35%	-	-	-	-	-	-	-	-	-	-	-
Federal Tax Credits		-							-		-
Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-
Excess Deferred Income Tax Reversal (ARAM)	-	-	-	-	-	-	-	-	-	-	-
Total Income Tax	-	-	-	-	-	-	-	-	-	-	-

Portland General Electric
UE-394, 2022 Test Year
Adjustments
($000)

	0 0 Blank 23	Prod. Cost	Transmsn. Cost	Dist. Cost	Ancillary Services	Metering Cost	Billing Cost	Other Consumer Cost	PGE Regulated Rev Req	Retail	Check Total
Sales to Consumers									-		-
Other Revenues									-		-
Total Operating Revenues	-	-	-	-	-	-	-	-	-	-	-
Net Variable Power Cost									-		-
Fixed Plant Cost									-		-
Transmission O&M									-		-
Distribution O&M				-					-		-
Total Fixed O&M	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts									-		-
Uncollectibles per Rev Req Model									-		-
Customer Service & Sales									-		-
OPUC Fee									-		
Admin. & General		-	-	-	-	-	-	-	-		-
Other O&M	-	-	-	-	-	-	-	-	-	-	-
Total Operating & Maintenance	-	-	-	-	-	-	-	-	-	-	-
Depreciation & Amortization		-	-	-	-	-	-	-	-		-
Other Taxes									-		-
Franchise Fee									-		-
Income Taxes	-	-	-	-	-	-	-	-	-	-	-
Total Oper. Expenses & Taxes	-	-	-	-	-	-	-	-	-	-	-
Utility Operating Income	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base											
Avg. Gross Plant		-	-	-	-	-	-	-	-		-
Avg. Accum. Deprec.									-		-
Avg. Accum. Def Tax		-	-	-	-	-	-	-	-	-	-
Avg. Accum. Def ITC									-		-
Avg. Net Utility Plant	-	-	-	-	-	-	-	-	-	-	-
Operating Materials & Fuel									-		-
Deferred Programs & Investments									-		-
Misc. Deferred Credits									-		-
Working Cash	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base	-	-	-	-	-	-	-	-	-	-	-
Rate of Return											
Implied Return on Equity											
Income Taxes											
Book Revenues	-	-	-	-	-	-	-	-	-	-	-
Book Expenses	-	-	-	-	-	-	-	-	-	-	-
Interest @ Weighted Cost of Debt	-	-	-	-	-	-	-	-	-	-	-
Production Deduction									-		-
Temporary Sch M Differences									-		-
Permanent M Differences									-		-
State Taxable Income	-	-	-	-	-	-	-	-	-	-	-
State Income Tax	-	-	-	-	-	-	-	-	-	-	-
State Tax Credit									-		-
Net State Income Tax	-	-	-	-	-	-	-	-	-	-	-
Federal Taxable Income	-	-	-	-	-	-	-	-	-	-	-
Fed Tax @ 35%	-	-	-	-	-	-	-	-	-	-	-
Federal Tax Credits									-		-
Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-
Excess Deferred Income Tax Reversal (ARAM)	-	-	-	-	-	-	-	-	-	-	-
Total Income Tax	-	-	-	-	-	-	-	-	-	-	-

Portland General Electric
UE-394, 2022 Test Year
Adjustments
($000)

	0 0 Blank 24	Prod. Cost	Transmsn. Cost	Dist. Cost	Ancillary Services	Metering Cost	Billing Cost	Other Consumer Cost	PGE Regulated Rev Req	Retail	Check Total
Sales to Consumers									-		-
Other Revenues									-		-
Total Operating Revenues	-	-	-	-	-	-	-	-	-	-	-
Net Variable Power Cost									-		-
Fixed Plant Cost									-		-
Transmission O&M									-		-
Distribution O&M				-					-		-
Total Fixed O&M	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts									-		-
Uncollectibles per Rev Req Model									-		-
Customer Service & Sales									-		-
OPUC Fee									-		
Admin. & General		-	-	-	-	-	-	-	-		-
Other O&M	-	-	-	-	-	-	-	-	-	-	-
Total Operating & Maintenance	-	-	-	-	-	-	-	-	-	-	-
Depreciation & Amortization									-		-
Other Taxes									-		-
Franchise Fee									-		-
Income Taxes	-	-	-	-	-	-	-	-	-	-	-
Total Oper. Expenses & Taxes	-	-	-	-	-	-	-	-	-	-	-
Utility Operating Income	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base											
Avg. Gross Plant	-	-	-	-	-	-	-	-	-		-
Avg. Accum. Deprec.									-		-
Avg. Accum. Def Tax		-	-	-	-	-	-	-	-	-	-
Avg. Accum. Def ITC									-		-
Avg. Net Utility Plant	-	-	-	-	-	-	-	-	-	-	-
Operating Materials & Fuel									-		-
Deferred Programs & Investments									-		-
Misc. Deferred Credits									-		-
Working Cash	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base	-	-	-	-	-	-	-	-	-	-	-
Rate of Return											
Implied Return on Equity											
Income Taxes											
Book Revenues	-	-	-	-	-	-	-	-	-	-	-
Book Expenses	-	-	-	-	-	-	-	-	-	-	-
Interest @ Weighted Cost of Debt	-	-	-	-	-	-	-	-	-	-	-
Production Deduction									-		-
Temporary Sch M Differences									-		-
Permanent M Differences									-		-
State Taxable Income	-	-	-	-	-	-	-	-	-	-	-
State Income Tax	-	-	-	-	-	-	-	-	-	-	-
State Tax Credit									-		-
Net State Income Tax	-	-	-	-	-	-	-	-	-	-	-
Federal Taxable Income	-	-	-	-	-	-	-	-	-	-	-
Fed Tax @ 35%	-	-	-	-	-	-	-	-	-	-	-
Federal Tax Credits									-		-
Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-
Excess Deferred Income Tax Reversal (ARAM)	-	-	-	-	-	-	-	-	-	-	-
Total Income Tax	-	-	-	-	-	-	-	-	-	-	-

Portland General Electric
UE-394, 2022 Test Year
Adjustments
($000)

	0 Blank 25	Prod. Cost	Transmsn. Cost	Dist. Cost	Ancillary Services	Metering Cost	Billing Cost	Other Consumer Cost	PGE Regulated Rev Req	Retail	Check Total
Sales to Consumers									-		-
Other Revenues									-		-
Total Operating Revenues	-	-	-	-	-	-	-	-	-	-	-
Net Variable Power Cost									-		-
Fixed Plant Cost									-		-
Transmission O&M									-		-
Distribution O&M									-		-
Total Fixed O&M	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts									-		-
Uncollectibles per Rev Req Model									-		-
Customer Service & Sales									-		-
OPUC Fee									-		
Admin. & General									-		-
Other O&M	-	-	-	-	-	-	-	-	-	-	-
Total Operating & Maintenance	-	-	-	-	-	-	-	-	-	-	-
Depreciation & Amortization				-					-		-
Other Taxes									-		-
Franchise Fee									-		-
Income Taxes	-	-	-	-	-	-	-	-	-	-	-
Total Oper. Expenses & Taxes	-	-	-	-	-	-	-	-	-	-	-
Utility Operating Income	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base											
Avg. Gross Plant				-					-		-
Avg. Accum. Deprec.				-					-		-
Avg. Accum. Def Tax				-					-		-
Avg. Accum. Def ITC									-		-
Avg. Net Utility Plant	-	-	-	-	-	-	-	-	-	-	-
Operating Materials & Fuel									-		-
Deferred Programs & Investments									-		-
Misc. Deferred Credits									-		-
Working Cash	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base	-	-	-	-	-	-	-	-	-	-	-
Rate of Return											
Implied Return on Equity											
Income Taxes											
Book Revenues	-	-	-	-	-	-	-	-	-	-	-
Book Expenses	-	-	-	-	-	-	-	-	-	-	-
Interest @ Weighted Cost of Debt	-	-	-	-	-	-	-	-	-	-	-
Production Deduction									-		-
Temporary Sch M Differences									-		-
Permanent M Differences									-		-
State Taxable Income	-	-	-	-	-	-	-	-	-	-	-
State Income Tax	-	-	-	-	-	-	-	-	-	-	-
State Tax Credit									-		-
Net State Income Tax	-	-	-	-	-	-	-	-	-	-	-
Federal Taxable Income	-	-	-	-	-	-	-	-	-	-	-
Fed Tax @ 35%	-	-	-	-	-	-	-	-	-	-	-
Federal Tax Credits									-		-
Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-
Excess Deferred Income Tax Reversal (ARAM)	-	-	-	-	-	-	-	-	-	-	-
Total Income Tax	-	-	-	-	-	-	-	-	-	-	-

Portland General Electric
UE-394, 2022 Test Year
Adjustments
($000)

	0 0 Blank 26	Prod. Cost	Transmsn. Cost	Dist. Cost	Ancillary Services	Metering Cost	Billing Cost	Other Consumer Cost	PGE Regulated Rev Req	Retail	Check Total
Sales to Consumers									-		-
Other Revenues									-		-
Total Operating Revenues	-	-	-	-	-	-	-	-	-	-	-
Net Variable Power Cost									-		-
Fixed Plant Cost									-		-
Transmission O&M									-		-
Distribution O&M				-					-		-
Total Fixed O&M	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts									-		-
Uncollectibles per Rev Req Model									-		-
Customer Service & Sales									-		-
OPUC Fee									-		
Admin. & General									-		-
Other O&M	-	-	-	-	-	-	-	-	-	-	-
Total Operating & Maintenance	-	-	-	-	-	-	-	-	-	-	-
Depreciation & Amortization									-		-
Other Taxes									-		-
Franchise Fee									-		-
Income Taxes	-	-	-	-	-	-	-	-	-	-	-
Total Oper. Expenses & Taxes	-	-	-	-	-	-	-	-	-	-	-
Utility Operating Income	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base											
Avg. Gross Plant									-		-
Avg. Accum. Deprec.									-		-
Avg. Accum. Def Tax		-							-		-
Avg. Accum. Def ITC									-		-
Avg. Net Utility Plant	-	-	-	-	-	-	-	-	-	-	-
Operating Materials & Fuel									-		-
Deferred Programs & Investments									-		-
Misc. Deferred Credits									-		-
Working Cash	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base	-	-	-	-	-	-	-	-	-	-	-
Rate of Return											
Implied Return on Equity											
Income Taxes											
Book Revenues	-	-	-	-	-	-	-	-	-	-	-
Book Expenses	-	-	-	-	-	-	-	-	-	-	-
Interest @ Weighted Cost of Debt	-	-	-	-	-	-	-	-	-	-	-
Production Deduction									-		-
Temporary Sch M Differences									-		-
Permanent M Differences									-		-
State Taxable Income	-	-	-	-	-	-	-	-	-	-	-
State Income Tax	-	-	-	-	-	-	-	-	-	-	-
State Tax Credit									-		-
Net State Income Tax	-	-	-	-	-	-	-	-	-	-	-
Federal Taxable Income	-	-	-	-	-	-	-	-	-	-	-
Fed Tax @ 35%	-	-	-	-	-	-	-	-	-	-	-
Federal Tax Credits									-		-
Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-
Excess Deferred Income Tax Reversal (ARAM)	-	-	-	-	-	-	-	-	-	-	-
Total Income Tax	-	-	-	-	-	-	-	-	-	-	-

Portland General Electric
UE-394, 2022 Test Year
Adjustments
($000)

	0 0 Blank 27	Prod. Cost	Transmsn. Cost	Dist. Cost	Ancillary Services	Metering Cost	Billing Cost	Other Consumer Cost	PGE Regulated Rev Req	Retail	Check Total
Sales to Consumers									-		-
Other Revenues									-		-
Total Operating Revenues	-	-	-	-	-	-	-	-	-	-	-
Net Variable Power Cost									-		-
Fixed Plant Cost									-		-
Transmission O&M			-						-		-
Distribution O&M									-		-
Total Fixed O&M	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts									-		-
Uncollectibles per Rev Req Model									-		-
Customer Service & Sales									-		-
OPUC Fee									-		
Admin. & General									-		-
Other O&M	-	-	-	-	-	-	-	-	-	-	-
Total Operating & Maintenance	-	-	-	-	-	-	-	-	-	-	-
Depreciation & Amortization		-	-	-	-	-	-	-	-	-	-
Other Taxes									-		-
Franchise Fee									-		-
Income Taxes	-	-	-	-	-	-	-	-	-	-	-
Total Oper. Expenses & Taxes	-	-	-	-	-	-	-	-	-	-	-
Utility Operating Income	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base											
Avg. Gross Plant									-		-
Avg. Accum. Deprec.		-	-	-	-	-	-	-	-		-
Avg. Accum. Def Tax		-	-	-	-	-	-	-	-		-
Avg. Accum. Def ITC									-		-
Avg. Net Utility Plant	-	-	-	-	-	-	-	-	-	-	-
Operating Materials & Fuel									-		-
Deferred Programs & Investments									-		-
Misc. Deferred Credits									-		-
Working Cash	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base	-	-	-	-	-	-	-	-	-	-	-
Rate of Return											
Implied Return on Equity											
Income Taxes											
Book Revenues	-	-	-	-	-	-	-	-	-	-	-
Book Expenses	-	-	-	-	-	-	-	-	-	-	-
Interest @ Weighted Cost of Debt	-	-	-	-	-	-	-	-	-	-	-
Production Deduction									-		-
Temporary Sch M Differences									-		-
Permanent M Differences									-		-
State Taxable Income	-	-	-	-	-	-	-	-	-	-	-
State Income Tax	-	-	-	-	-	-	-	-	-	-	-
State Tax Credit									-		-
Net State Income Tax	-	-	-	-	-	-	-	-	-	-	-
Federal Taxable Income	-	-	-	-	-	-	-	-	-	-	-
Fed Tax @ 35%	-	-	-	-	-	-	-	-	-	-	-
Federal Tax Credits									-		-
Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-
Excess Deferred Income Tax Reversal (ARAM)	-	-	-	-	-	-	-	-	-	-	-
Total Income Tax	-	-	-	-	-	-	-	-	-	-	-

Portland General Electric
UE-394, 2022 Test Year
Adjustments
($000)

	0 0 Blank 28	Prod. Cost	Transmsn. Cost	Dist. Cost	Ancillary Services	Metering Cost	Billing Cost	Other Consumer Cost	PGE Regulated Rev Req	Retail	Check Total
Sales to Consumers									-		-
Other Revenues									-		-
Total Operating Revenues	-	-	-	-	-	-	-	-	-	-	-
Net Variable Power Cost									-		-
Fixed Plant Cost		-							-		-
Transmission O&M									-		-
Distribution O&M				-					-		-
Total Fixed O&M	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts									-		-
Uncollectibles per Rev Req Model									-		-
Customer Service & Sales									-		-
OPUC Fee									-		
Admin. & General									-		-
Other O&M	-	-	-	-	-	-	-	-	-	-	-
Total Operating & Maintenance	-	-	-	-	-	-	-	-	-	-	-
Depreciation & Amortization									-		-
Other Taxes									-		-
Franchise Fee									-		-
Income Taxes	-	-	-	-	-	-	-	-	-	-	-
Total Oper. Expenses & Taxes	-	-	-	-	-	-	-	-	-	-	-
Utility Operating Income	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base											
Avg. Gross Plant									-		-
Avg. Accum. Deprec.									-		-
Avg. Accum. Def Tax									-		-
Avg. Accum. Def ITC									-		-
Avg. Net Utility Plant	-	-	-	-	-	-	-	-	-	-	-
Operating Materials & Fuel									-		-
Deferred Programs & Investments		-							-		-
Misc. Deferred Credits									-		-
Working Cash	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base	-	-	-	-	-	-	-	-	-	-	-
Rate of Return											
Implied Return on Equity											
Income Taxes											
Book Revenues	-	-	-	-	-	-	-	-	-	-	-
Book Expenses	-	-	-	-	-	-	-	-	-	-	-
Interest @ Weighted Cost of Debt	-	-	-	-	-	-	-	-	-	-	-
Production Deduction									-		-
Temporary Sch M Differences									-		-
Permanent M Differences									-		-
State Taxable Income	-	-	-	-	-	-	-	-	-	-	-
State Income Tax	-	-	-	-	-	-	-	-	-	-	-
State Tax Credit									-		-
Net State Income Tax	-	-	-	-	-	-	-	-	-	-	-
Federal Taxable Income	-	-	-	-	-	-	-	-	-	-	-
Fed Tax @ 35%	-	-	-	-	-	-	-	-	-	-	-
Federal Tax Credits									-		-
Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-
Excess Deferred Income Tax Reversal (ARAM)	-	-	-	-	-	-	-	-	-	-	-
Total Income Tax	-	-	-	-	-	-	-	-	-	-	-

Portland General Electric
UE-394, 2022 Test Year
Adjustments
($000)

	0 0 Blank 29	Prod. Cost	Transmsn. Cost	Dist. Cost	Ancillary Services	Metering Cost	Billing Cost	Other Consumer Cost	PGE Regulated Rev Req	Retail	Check Total
Sales to Consumers									-		-
Other Revenues									-		-
Total Operating Revenues	-	-	-	-	-	-	-	-	-	-	-
Net Variable Power Cost									-		-
Fixed Plant Cost		-							-		-
Transmission O&M									-		-
Distribution O&M									-		-
Total Fixed O&M	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts									-		-
Uncollectibles per Rev Req Model									-		-
Customer Service & Sales									-		-
OPUC Fee									-		
Admin. & General		-	-	-	-	-	-	-	-	-	-
Other O&M	-	-	-	-	-	-	-	-	-	-	-
Total Operating & Maintenance	-	-	-	-	-	-	-	-	-	-	-
Depreciation & Amortization									-		-
Other Taxes									-		-
Franchise Fee									-		-
Income Taxes	-	-	-	-	-	-	-	-	-	-	-
Total Oper. Expenses & Taxes	-	-	-	-	-	-	-	-	-	-	-
Utility Operating Income	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base											
Avg. Gross Plant									-		-
Avg. Accum. Deprec.									-		-
Avg. Accum. Def Tax									-		-
Avg. Accum. Def ITC									-		-
Avg. Net Utility Plant	-	-	-	-	-	-	-	-	-	-	-
Operating Materials & Fuel									-		-
Deferred Programs & Investments		-							-		-
Misc. Deferred Credits									-		-
Working Cash	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base	-	-	-	-	-	-	-	-	-	-	-
Rate of Return											
Implied Return on Equity											
Income Taxes											
Book Revenues	-	-	-	-	-	-	-	-	-	-	-
Book Expenses	-	-	-	-	-	-	-	-	-	-	-
Interest @ Weighted Cost of Debt	-	-	-	-	-	-	-	-	-	-	-
Production Deduction									-		-
Temporary Sch M Differences									-		-
Permanent M Differences									-		-
State Taxable Income	-	-	-	-	-	-	-	-	-	-	-
State Income Tax	-	-	-	-	-	-	-	-	-	-	-
State Tax Credit									-		-
Net State Income Tax	-	-	-	-	-	-	-	-	-	-	-
Federal Taxable Income	-	-	-	-	-	-	-	-	-	-	-
Fed Tax @ 35%	-	-	-	-	-	-	-	-	-	-	-
Federal Tax Credits									-		-
Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-
Excess Deferred Income Tax Reversal (ARAM)	-	-	-	-	-	-	-	-	-	-	-
Total Income Tax	-	-	-	-	-	-	-	-	-	-	-

Portland General Electric
UE-394, 2022 Test Year
Adjustments
($000)

	0 0 Blank 30	Prod. Cost	Transmsn. Cost	Dist. Cost	Ancillary Services	Metering Cost	Billing Cost	Other Consumer Cost	PGE Regulated Rev Req	Retail	Check Total
Sales to Consumers									-		-
Other Revenues									-		-
Total Operating Revenues	-	-	-	-	-	-	-	-	-	-	-
Net Variable Power Cost									-		-
Fixed Plant Cost									-		-
Transmission O&M									-		-
Distribution O&M									-		-
Total Fixed O&M	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts									-		-
Uncollectibles per Rev Req Model									-		-
Customer Service & Sales									-		-
OPUC Fee									-		
Admin. & General		-	-	-	-	-	-	-	-	-	-
Other O&M	-	-	-	-	-	-	-	-	-	-	-
Total Operating & Maintenance	-	-	-	-	-	-	-	-	-	-	-
Depreciation & Amortization									-		-
Other Taxes									-		-
Franchise Fee									-		-
Income Taxes	-	-	-	-	-	-	-	-	-	-	-
Total Oper. Expenses & Taxes	-	-	-	-	-	-	-	-	-	-	-
Utility Operating Income	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base											
Avg. Gross Plant									-		-
Avg. Accum. Deprec.									-		-
Avg. Accum. Def Tax									-		-
Avg. Accum. Def ITC									-		-
Avg. Net Utility Plant	-	-	-	-	-	-	-	-	-	-	-
Operating Materials & Fuel									-		-
Deferred Programs & Investments									-		-
Misc. Deferred Credits									-		-
Working Cash	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base	-	-	-	-	-	-	-	-	-	-	-
Rate of Return											
Implied Return on Equity											
Income Taxes											
Book Revenues	-	-	-	-	-	-	-	-	-	-	-
Book Expenses	-	-	-	-	-	-	-	-	-	-	-
Interest @ Weighted Cost of Debt	-	-	-	-	-	-	-	-	-	-	-
Production Deduction									-		-
Temporary Sch M Differences									-		-
Permanent M Differences									-		-
State Taxable Income	-	-	-	-	-	-	-	-	-	-	-
State Income Tax	-	-	-	-	-	-	-	-	-	-	-
State Tax Credit									-		-
Net State Income Tax	-	-	-	-	-	-	-	-	-	-	-
Federal Taxable Income	-	-	-	-	-	-	-	-	-	-	-
Fed Tax @ 35%	-	-	-	-	-	-	-	-	-	-	-
Federal Tax Credits									-		-
Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-
Excess Deferred Income Tax Reversal (ARAM)	-	-	-	-	-	-	-	-	-	-	-
Total Income Tax	-	-	-	-	-	-	-	-	-	-	-

Portland General Electric
UE-394, 2022 Test Year
Adjustments
($000)

	0 0 Blank 31	Prod. Cost	Transmsn. Cost	Dist. Cost	Ancillary Services	Metering Cost	Billing Cost	Other Consumer Cost	PGE Regulated Rev Req	Retail	Check Total
Sales to Consumers									-		-
Other Revenues									-		-
Total Operating Revenues	-	-	-	-	-	-	-	-	-	-	-
Net Variable Power Cost									-		-
Fixed Plant Cost									-		-
Transmission O&M									-		-
Distribution O&M									-		-
Total Fixed O&M	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts									-		-
Uncollectibles per Rev Req Model									-		-
Customer Service & Sales									-		-
OPUC Fee									-		
Admin. & General									-		-
Other O&M	-	-	-	-	-	-	-	-	-	-	-
Total Operating & Maintenance	-	-	-	-	-	-	-	-	-	-	-
Depreciation & Amortization									-		-
Other Taxes									-		-
Franchise Fee									-		-
Income Taxes	-	-	-	-	-	-	-	-	-	-	-
Total Oper. Expenses & Taxes	-	-	-	-	-	-	-	-	-	-	-
Utility Operating Income	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base											
Avg. Gross Plant									-		-
Avg. Accum. Deprec.									-		-
Avg. Accum. Def Tax									-		-
Avg. Accum. Def ITC									-		-
Avg. Net Utility Plant	-	-	-	-	-	-	-	-	-	-	-
Operating Materials & Fuel									-		-
Deferred Programs & Investments									-		-
Misc. Deferred Credits									-		-
Working Cash	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base	-	-	-	-	-	-	-	-	-	-	-
Rate of Return											
Implied Return on Equity											
Income Taxes											
Book Revenues	-	-	-	-	-	-	-	-	-	-	-
Book Expenses	-	-	-	-	-	-	-	-	-	-	-
Interest @ Weighted Cost of Debt	-	-	-	-	-	-	-	-	-	-	-
Production Deduction									-		-
Temporary Sch M Differences									-		-
Permanent M Differences									-		-
State Taxable Income	-	-	-	-	-	-	-	-	-	-	-
State Income Tax	-	-	-	-	-	-	-	-	-	-	-
State Tax Credit									-		-
Net State Income Tax	-	-	-	-	-	-	-	-	-	-	-
Federal Taxable Income	-	-	-	-	-	-	-	-	-	-	-
Fed Tax @ 35%	-	-	-	-	-	-	-	-	-	-	-
Federal Tax Credits									-		-
Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-
Excess Deferred Income Tax Reversal (ARAM)	-	-	-	-	-	-	-	-	-	-	-
Total Income Tax	-	-	-	-	-	-	-	-	-	-	-

Portland General Electric
UE-394, 2022 Test Year
Adjustments
($000)

	0 0 Blank 32	Prod. Cost	Transmsn. Cost	Dist. Cost	Ancillary Services	Metering Cost	Billing Cost	Other Consumer Cost	PGE Regulated Rev Req	Retail	Check Total
Sales to Consumers									-		-
Other Revenues									-		-
Total Operating Revenues	-	-	-	-	-	-	-	-	-	-	-
Net Variable Power Cost									-		-
Fixed Plant Cost									-		-
Transmission O&M									-		-
Distribution O&M									-		-
Total Fixed O&M	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts									-		-
Uncollectibles per Rev Req Model									-		-
Customer Service & Sales									-		-
OPUC Fee									-		
Admin. & General									-		-
Other O&M	-	-	-	-	-	-	-	-	-	-	-
Total Operating & Maintenance	-	-	-	-	-	-	-	-	-	-	-
Depreciation & Amortization		-							-		-
Other Taxes									-		-
Franchise Fee									-		-
Income Taxes	-	-	-	-	-	-	-	-	-	-	-
Total Oper. Expenses & Taxes	-	-	-	-	-	-	-	-	-	-	-
Utility Operating Income	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base											
Avg. Gross Plant									-		-
Avg. Accum. Deprec.		-							-		-
Avg. Accum. Def Tax									-		-
Avg. Accum. Def ITC									-		-
Avg. Net Utility Plant	-	-	-	-	-	-	-	-	-	-	-
Operating Materials & Fuel									-		-
Deferred Programs & Investments									-		-
Misc. Deferred Credits									-		-
Working Cash	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base	-	-	-	-	-	-	-	-	-	-	-
Rate of Return											
Implied Return on Equity											
Income Taxes											
Book Revenues	-	-	-	-	-	-	-	-	-	-	-
Book Expenses	-	-	-	-	-	-	-	-	-	-	-
Interest @ Weighted Cost of Debt	-	-	-	-	-	-	-	-	-	-	-
Production Deduction									-		-
Temporary Sch M Differences									-		-
Permanent M Differences									-		-
State Taxable Income	-	-	-	-	-	-	-	-	-	-	-
State Income Tax	-	-	-	-	-	-	-	-	-	-	-
State Tax Credit									-		-
Net State Income Tax	-	-	-	-	-	-	-	-	-	-	-
Federal Taxable Income	-	-	-	-	-	-	-	-	-	-	-
Fed Tax @ 35%	-	-	-	-	-	-	-	-	-	-	-
Federal Tax Credits									-		-
Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-
Excess Deferred Income Tax Reversal (ARAM)	-	-	-	-	-	-	-	-	-	-	-
Total Income Tax	-	-	-	-	-	-	-	-	-	-	-

Portland General Electric
UE-394, 2022 Test Year
Adjustments
($000)

	0 0 Blank 33	Prod. Cost	Transmsn. Cost	Dist. Cost	Ancillary Services	Metering Cost	Billing Cost	Other Consumer Cost	PGE Regulated Rev Req	Retail	Check Total
Sales to Consumers									-		-
Other Revenues									-		-
Total Operating Revenues	-	-	-	-	-	-	-	-	-	-	-
Net Variable Power Cost									-		-
Fixed Plant Cost									-		-
Transmission O&M									-		-
Distribution O&M									-		-
Total Fixed O&M	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts									-		-
Uncollectibles per Rev Req Model									-		-
Customer Service & Sales									-		-
OPUC Fee									-		
Admin. & General									-		-
Other O&M	-	-	-	-	-	-	-	-	-	-	-
Total Operating & Maintenance	-	-	-	-	-	-	-	-	-	-	-
Depreciation & Amortization									-		-
Other Taxes									-		-
Franchise Fee									-		-
Income Taxes	-	-	-	-	-	-	-	-	-	-	-
Total Oper. Expenses & Taxes	-	-	-	-	-	-	-	-	-	-	-
Utility Operating Income	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base											
Avg. Gross Plant									-		-
Avg. Accum. Deprec.									-		-
Avg. Accum. Def Tax									-		-
Avg. Accum. Def ITC									-		-
Avg. Net Utility Plant	-	-	-	-	-	-	-	-	-	-	-
Operating Materials & Fuel									-		-
Deferred Programs & Investments									-		-
Misc. Deferred Credits									-		-
Working Cash	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base	-	-	-	-	-	-	-	-	-	-	-
Rate of Return											
Implied Return on Equity											
Income Taxes											
Book Revenues	-	-	-	-	-	-	-	-	-	-	-
Book Expenses	-	-	-	-	-	-	-	-	-	-	-
Interest @ Weighted Cost of Debt	-	-	-	-	-	-	-	-	-	-	-
Production Deduction									-		-
Temporary Sch M Differences									-		-
Permanent M Differences									-		-
State Taxable Income	-	-	-	-	-	-	-	-	-	-	-
State Income Tax	-	-	-	-	-	-	-	-	-	-	-
State Tax Credit									-		-
Net State Income Tax	-	-	-	-	-	-	-	-	-	-	-
Federal Taxable Income	-	-	-	-	-	-	-	-	-	-	-
Fed Tax @ 35%	-	-	-	-	-	-	-	-	-	-	-
Federal Tax Credits									-		-
Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-
Excess Deferred Income Tax Reversal (ARAM)	-	-	-	-	-	-	-	-	-	-	-
Total Income Tax	-	-	-	-	-	-	-	-	-	-	-

Portland General Electric
UE-394, 2022 Test Year
Adjustments
($000)

	0 0 Blank 34	Prod. Cost	Transmsn. Cost	Dist. Cost	Ancillary Services	Metering Cost	Billing Cost	Other Consumer Cost	PGE Regulated Rev Req	Retail	Check Total
Sales to Consumers									-		-
Other Revenues									-		-
Total Operating Revenues	-	-	-	-	-	-	-	-	-	-	-
Net Variable Power Cost									-		-
Fixed Plant Cost									-		-
Transmission O&M									-		-
Distribution O&M									-		-
Total Fixed O&M	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts									-		-
Uncollectibles per Rev Req Model									-		-
Customer Service & Sales									-		-
OPUC Fee									-		
Admin. & General									-		-
Other O&M	-	-	-	-	-	-	-	-	-	-	-
Total Operating & Maintenance	-	-	-	-	-	-	-	-	-	-	-
Depreciation & Amortization									-		-
Other Taxes									-		-
Franchise Fee									-		-
Income Taxes	-	-	-	-	-	-	-	-	-	-	-
Total Oper. Expenses & Taxes	-	-	-	-	-	-	-	-	-	-	-
Utility Operating Income	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base											
Avg. Gross Plant		-							-		-
Avg. Accum. Deprec.									-		-
Avg. Accum. Def Tax									-		-
Avg. Accum. Def ITC									-		-
Avg. Net Utility Plant	-	-	-	-	-	-	-	-	-	-	-
Operating Materials & Fuel									-		-
Deferred Programs & Investments									-		-
Misc. Deferred Credits									-		-
Working Cash	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base	-	-	-	-	-	-	-	-	-	-	-
Rate of Return											
Implied Return on Equity											
Income Taxes											
Book Revenues	-	-	-	-	-	-	-	-	-	-	-
Book Expenses	-	-	-	-	-	-	-	-	-	-	-
Interest @ Weighted Cost of Debt	-	-	-	-	-	-	-	-	-	-	-
Production Deduction									-		-
Temporary Sch M Differences									-		-
Permanent M Differences									-		-
State Taxable Income	-	-	-	-	-	-	-	-	-	-	-
State Income Tax	-	-	-	-	-	-	-	-	-	-	-
State Tax Credit									-		-
Net State Income Tax	-	-	-	-	-	-	-	-	-	-	-
Federal Taxable Income	-	-	-	-	-	-	-	-	-	-	-
Fed Tax @ 35%	-	-	-	-	-	-	-	-	-	-	-
Federal Tax Credits									-		-
Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-
Excess Deferred Income Tax Reversal (ARAM)	-	-	-	-	-	-	-	-	-	-	-
Total Income Tax	-	-	-	-	-	-	-	-	-	-	-

Portland General Electric
UE-394, 2022 Test Year
Adjustments
($000)

	0 0 Blank 35	Prod. Cost	Transmsn. Cost	Dist. Cost	Ancillary Services	Metering Cost	Billing Cost	Other Consumer Cost	PGE Regulated Rev Req	Retail	Check Total
Sales to Consumers									-		-
Other Revenues									-		-
Total Operating Revenues	-	-	-	-	-	-	-	-	-	-	-
Net Variable Power Cost									-		-
Fixed Plant Cost									-		-
Transmission O&M									-		-
Distribution O&M									-		-
Total Fixed O&M	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts									-		-
Uncollectibles per Rev Req Model									-		-
Customer Service & Sales									-		-
OPUC Fee									-		
Admin. & General									-		-
Other O&M	-	-	-	-	-	-	-	-	-	-	-
Total Operating & Maintenance	-	-	-	-	-	-	-	-	-	-	-
Depreciation & Amortization									-		-
Other Taxes									-		-
Franchise Fee									-		-
Income Taxes	-	-	-	-	-	-	-	-	-	-	-
Total Oper. Expenses & Taxes	-	-	-	-	-	-	-	-	-	-	-
Utility Operating Income	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base											
Avg. Gross Plant									-		-
Avg. Accum. Deprec.									-		-
Avg. Accum. Def Tax									-		-
Avg. Accum. Def ITC									-		-
Avg. Net Utility Plant	-	-	-	-	-	-	-	-	-	-	-
Operating Materials & Fuel									-		-
Deferred Programs & Investments									-		-
Misc. Deferred Credits									-		-
Working Cash	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base	-	-	-	-	-	-	-	-	-	-	-
Rate of Return											
Implied Return on Equity											
Income Taxes											
Book Revenues	-	-	-	-	-	-	-	-	-	-	-
Book Expenses	-	-	-	-	-	-	-	-	-	-	-
Interest @ Weighted Cost of Debt	-	-	-	-	-	-	-	-	-	-	-
Production Deduction									-		-
Temporary Sch M Differences									-		-
Permanent M Differences									-		-
State Taxable Income	-	-	-	-	-	-	-	-	-	-	-
State Income Tax	-	-	-	-	-	-	-	-	-	-	-
State Tax Credit									-		-
Net State Income Tax	-	-	-	-	-	-	-	-	-	-	-
Federal Taxable Income	-	-	-	-	-	-	-	-	-	-	-
Fed Tax @ 35%	-	-	-	-	-	-	-	-	-	-	-
Federal Tax Credits									-		-
Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-
Excess Deferred Income Tax Reversal (ARAM)	-	-	-	-	-	-	-	-	-	-	-
Total Income Tax	-	-	-	-	-	-	-	-	-	-	-

Portland General Electric
UE-394, 2022 Test Year
Adjustments
($000)

	0 0 Blank 36	Prod. Cost	Transmsn. Cost	Dist. Cost	Ancillary Services	Metering Cost	Billing Cost	Other Consumer Cost	PGE Regulated Rev Req	Retail	Check Total
Sales to Consumers									-		-
Other Revenues									-		-
Total Operating Revenues	-	-	-	-	-	-	-	-	-	-	-
Net Variable Power Cost									-		-
Fixed Plant Cost									-		-
Transmission O&M									-		-
Distribution O&M									-		-
Total Fixed O&M	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts									-		-
Uncollectibles per Rev Req Model									-		-
Customer Service & Sales									-		-
OPUC Fee									-		
Admin. & General									-		-
Other O&M	-	-	-	-	-	-	-	-	-	-	-
Total Operating & Maintenance	-	-	-	-	-	-	-	-	-	-	-
Depreciation & Amortization									-		-
Other Taxes									-		-
Franchise Fee									-		-
Income Taxes	-	-	-	-	-	-	-	-	-	-	-
Total Oper. Expenses & Taxes	-	-	-	-	-	-	-	-	-	-	-
Utility Operating Income	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base											
Avg. Gross Plant				-					-		-
Avg. Accum. Deprec.									-		-
Avg. Accum. Def Tax									-		-
Avg. Accum. Def ITC									-		-
Avg. Net Utility Plant	-	-	-	-	-	-	-	-	-	-	-
Operating Materials & Fuel									-		-
Deferred Programs & Investments									-		-
Misc. Deferred Credits									-		-
Working Cash	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base	-	-	-	-	-	-	-	-	-	-	-
Rate of Return											
Implied Return on Equity											
Income Taxes											
Book Revenues	-	-	-	-	-	-	-	-	-	-	-
Book Expenses	-	-	-	-	-	-	-	-	-	-	-
Interest @ Weighted Cost of Debt	-	-	-	-	-	-	-	-	-	-	-
Production Deduction									-		-
Temporary Sch M Differences									-		-
Permanent M Differences									-		-
State Taxable Income	-	-	-	-	-	-	-	-	-	-	-
State Income Tax	-	-	-	-	-	-	-	-	-	-	-
State Tax Credit									-		-
Net State Income Tax	-	-	-	-	-	-	-	-	-	-	-
Federal Taxable Income	-	-	-	-	-	-	-	-	-	-	-
Fed Tax @ 35%	-	-	-	-	-	-	-	-	-	-	-
Federal Tax Credits									-		-
Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-
Excess Deferred Income Tax Reversal (ARAM)	-	-	-	-	-	-	-	-	-	-	-
Total Income Tax	-	-	-	-	-	-	-	-	-	-	-

Portland General Electric
UE-394, 2022 Test Year
Adjustments
($000)

	0 0 Blank 37	Prod. Cost	Transmsn. Cost	Dist. Cost	Ancillary Services	Metering Cost	Billing Cost	Other Consumer Cost	PGE Regulated Rev Req	Retail	Check Total
Sales to Consumers									-		-
Other Revenues									-		-
Total Operating Revenues	-	-	-	-	-	-	-	-	-	-	-
Net Variable Power Cost									-		-
Fixed Plant Cost									-		-
Transmission O&M									-		-
Distribution O&M									-		-
Total Fixed O&M	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts									-		-
Uncollectibles per Rev Req Model									-		-
Customer Service & Sales									-		-
OPUC Fee									-		
Admin. & General									-		-
Other O&M	-	-	-	-	-	-	-	-	-	-	-
Total Operating & Maintenance	-	-	-	-	-	-	-	-	-	-	-
Depreciation & Amortization									-		-
Other Taxes									-		-
Franchise Fee									-		-
Income Taxes	-	-	-	-	-	-	-	-	-	-	-
Total Oper. Expenses & Taxes	-	-	-	-	-	-	-	-	-	-	-
Utility Operating Income	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base											
Avg. Gross Plant									-		-
Avg. Accum. Deprec.									-		-
Avg. Accum. Def Tax									-		-
Avg. Accum. Def ITC									-		-
Avg. Net Utility Plant	-	-	-	-	-	-	-	-	-	-	-
Operating Materials & Fuel									-		-
Deferred Programs & Investments									-		-
Misc. Deferred Credits									-		-
Working Cash	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base	-	-	-	-	-	-	-	-	-	-	-
Rate of Return											
Implied Return on Equity											
Income Taxes											
Book Revenues	-	-	-	-	-	-	-	-	-	-	-
Book Expenses	-	-	-	-	-	-	-	-	-	-	-
Interest @ Weighted Cost of Debt	-	-	-	-	-	-	-	-	-	-	-
Production Deduction									-		-
Temporary Sch M Differences									-		-
Permanent M Differences									-		-
State Taxable Income	-	-	-	-	-	-	-	-	-	-	-
State Income Tax	-	-	-	-	-	-	-	-	-	-	-
State Tax Credit									-		-
Net State Income Tax	-	-	-	-	-	-	-	-	-	-	-
Federal Taxable Income	-	-	-	-	-	-	-	-	-	-	-
Fed Tax @ 35%	-	-	-	-	-	-	-	-	-	-	-
Federal Tax Credits									-		-
Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-
Excess Deferred Income Tax Reversal (ARAM)	-	-	-	-	-	-	-	-	-	-	-
Total Income Tax	-	-	-	-	-	-	-	-	-	-	-

Portland General Electric
UE-394, 2022 Test Year
Adjustments
($000)

	0 0 Blank 38	Prod. Cost	Transmsn. Cost	Dist. Cost	Ancillary Services	Metering Cost	Billing Cost	Other Consumer Cost	PGE Regulated Rev Req	Retail	Check Total
Sales to Consumers									-		-
Other Revenues									-		-
Total Operating Revenues	-	-	-	-	-	-	-	-	-	-	-
Net Variable Power Cost									-		-
Fixed Plant Cost									-		-
Transmission O&M									-		-
Distribution O&M									-		-
Total Fixed O&M	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts									-		-
Uncollectibles per Rev Req Model									-		-
Customer Service & Sales									-		-
OPUC Fee									-		
Admin. & General									-		-
Other O&M	-	-	-	-	-	-	-	-	-	-	-
Total Operating & Maintenance	-	-	-	-	-	-	-	-	-	-	-
Depreciation & Amortization									-		-
Other Taxes									-		-
Franchise Fee									-		-
Income Taxes	-	-	-	-	-	-	-	-	-	-	-
Total Oper. Expenses & Taxes	-	-	-	-	-	-	-	-	-	-	-
Utility Operating Income	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base											
Avg. Gross Plant									-		-
Avg. Accum. Deprec.									-		-
Avg. Accum. Def Tax									-		-
Avg. Accum. Def ITC									-		-
Avg. Net Utility Plant	-	-	-	-	-	-	-	-	-	-	-
Operating Materials & Fuel									-		-
Deferred Programs & Investments									-		-
Misc. Deferred Credits									-		-
Working Cash	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base	-	-	-	-	-	-	-	-	-	-	-
Rate of Return											
Implied Return on Equity											
Income Taxes											
Book Revenues	-	-	-	-	-	-	-	-	-	-	-
Book Expenses	-	-	-	-	-	-	-	-	-	-	-
Interest @ Weighted Cost of Debt	-	-	-	-	-	-	-	-	-	-	-
Production Deduction									-		-
Temporary Sch M Differences									-		-
Permanent M Differences									-		-
State Taxable Income	-	-	-	-	-	-	-	-	-	-	-
State Income Tax	-	-	-	-	-	-	-	-	-	-	-
State Tax Credit									-		-
Net State Income Tax	-	-	-	-	-	-	-	-	-	-	-
Federal Taxable Income	-	-	-	-	-	-	-	-	-	-	-
Fed Tax @ 35%	-	-	-	-	-	-	-	-	-	-	-
Federal Tax Credits									-		-
Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-
Excess Deferred Income Tax Reversal (ARAM)	-	-	-	-	-	-	-	-	-	-	-
Total Income Tax	-	-	-	-	-	-	-	-	-	-	-

Portland General Electric
UE-394, 2022 Test Year
Adjustments
($000)

	0 0 Blank 39	Prod. Cost	Transmsn. Cost	Dist. Cost	Ancillary Services	Metering Cost	Billing Cost	Other Consumer Cost	PGE Regulated Rev Req	Retail	Check Total
Sales to Consumers									-		-
Other Revenues									-		-
Total Operating Revenues	-	-	-	-	-	-	-	-	-	-	-
Net Variable Power Cost									-		-
Fixed Plant Cost									-		-
Transmission O&M									-		-
Distribution O&M									-		-
Total Fixed O&M	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts									-		-
Uncollectibles per Rev Req Model									-		-
Customer Service & Sales									-		-
OPUC Fee									-		
Admin. & General									-		-
Other O&M	-	-	-	-	-	-	-	-	-	-	-
Total Operating & Maintenance	-	-	-	-	-	-	-	-	-	-	-
Depreciation & Amortization									-		-
Other Taxes									-		-
Franchise Fee									-		-
Income Taxes	-	-	-	-	-	-	-	-	-	-	-
Total Oper. Expenses & Taxes	-	-	-	-	-	-	-	-	-	-	-
Utility Operating Income	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base											
Avg. Gross Plant									-		-
Avg. Accum. Deprec.									-		-
Avg. Accum. Def Tax									-		-
Avg. Accum. Def ITC									-		-
Avg. Net Utility Plant	-	-	-	-	-	-	-	-	-	-	-
Operating Materials & Fuel									-		-
Deferred Programs & Investments									-		-
Misc. Deferred Credits									-		-
Working Cash	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base	-	-	-	-	-	-	-	-	-	-	-
Rate of Return											
Implied Return on Equity											
Income Taxes											
Book Revenues	-	-	-	-	-	-	-	-	-	-	-
Book Expenses	-	-	-	-	-	-	-	-	-	-	-
Interest @ Weighted Cost of Debt	-	-	-	-	-	-	-	-	-	-	-
Production Deduction									-		-
Temporary Sch M Differences									-		-
Permanent M Differences									-		-
State Taxable Income	-	-	-	-	-	-	-	-	-	-	-
State Income Tax	-	-	-	-	-	-	-	-	-	-	-
State Tax Credit									-		-
Net State Income Tax	-	-	-	-	-	-	-	-	-	-	-
Federal Taxable Income	-	-	-	-	-	-	-	-	-	-	-
Fed Tax @ 35%	-	-	-	-	-	-	-	-	-	-	-
Federal Tax Credits									-		-
Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-
Excess Deferred Income Tax Reversal (ARAM)	-	-	-	-	-	-	-	-	-	-	-
Total Income Tax	-	-	-	-	-	-	-	-	-	-	-

Portland General Electric
UE-394, 2022 Test Year
Adjustments
($000)

	0 0 Blank 40	Prod. Cost	Transmsn. Cost	Dist. Cost	Ancillary Services	Metering Cost	Billing Cost	Other Consumer Cost	PGE Regulated Rev Req	Retail	Check Total
Sales to Consumers									-		-
Other Revenues									-		-
Total Operating Revenues	-	-	-	-	-	-	-	-	-	-	-
Net Variable Power Cost									-		-
Fixed Plant Cost									-		-
Transmission O&M									-		-
Distribution O&M									-		-
Total Fixed O&M	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts									-		-
Uncollectibles per Rev Req Model									-		-
Customer Service & Sales									-		-
OPUC Fee									-		
Admin. & General									-		-
Other O&M	-	-	-	-	-	-	-	-	-	-	-
Total Operating & Maintenance	-	-	-	-	-	-	-	-	-	-	-
Depreciation & Amortization									-		-
Other Taxes									-		-
Franchise Fee									-		-
Income Taxes	-	-	-	-	-	-	-	-	-	-	-
Total Oper. Expenses & Taxes	-	-	-	-	-	-	-	-	-	-	-
Utility Operating Income	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base											
Avg. Gross Plant									-		-
Avg. Accum. Deprec.									-		-
Avg. Accum. Def Tax									-		-
Avg. Accum. Def ITC									-		-
Avg. Net Utility Plant	-	-	-	-	-	-	-	-	-	-	-
Operating Materials & Fuel									-		-
Deferred Programs & Investments									-		-
Misc. Deferred Credits									-		-
Working Cash	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base	-	-	-	-	-	-	-	-	-	-	-
Rate of Return											
Implied Return on Equity											
Income Taxes											
Book Revenues	-	-	-	-	-	-	-	-	-	-	-
Book Expenses	-	-	-	-	-	-	-	-	-	-	-
Interest @ Weighted Cost of Debt	-	-	-	-	-	-	-	-	-	-	-
Production Deduction									-		-
Temporary Sch M Differences									-		-
Permanent M Differences									-		-
State Taxable Income	-	-	-	-	-	-	-	-	-	-	-
State Income Tax	-	-	-	-	-	-	-	-	-	-	-
State Tax Credit									-		-
Net State Income Tax	-	-	-	-	-	-	-	-	-	-	-
Federal Taxable Income	-	-	-	-	-	-	-	-	-	-	-
Fed Tax @ 35%	-	-	-	-	-	-	-	-	-	-	-
Federal Tax Credits									-		-
Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-
Excess Deferred Income Tax Reversal (ARAM)	-	-	-	-	-	-	-	-	-	-	-
Total Income Tax	-	-	-	-	-	-	-	-	-	-	-

Portland General Electric
UE-394, 2022 Test Year
Adjustments
($000)

	0 0 Blank 41	Prod. Cost	Transmsn. Cost	Dist. Cost	Ancillary Services	Metering Cost	Billing Cost	Other Consumer Cost	PGE Regulated Rev Req	Retail	Check Total
Sales to Consumers									-		-
Other Revenues									-		-
Total Operating Revenues	-	-	-	-	-	-	-	-	-	-	-
Net Variable Power Cost									-		-
Fixed Plant Cost									-		-
Transmission O&M									-		-
Distribution O&M									-		-
Total Fixed O&M	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts									-		-
Uncollectibles per Rev Req Model									-		-
Customer Service & Sales									-		-
OPUC Fee									-		
Admin. & General									-		-
Other O&M	-	-	-	-	-	-	-	-	-	-	-
Total Operating & Maintenance	-	-	-	-	-	-	-	-	-	-	-
Depreciation & Amortization									-		-
Other Taxes									-		-
Franchise Fee									-		-
Income Taxes	-	-	-	-	-	-	-	-	-	-	-
Total Oper. Expenses & Taxes	-	-	-	-	-	-	-	-	-	-	-
Utility Operating Income	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base											
Avg. Gross Plant									-		-
Avg. Accum. Deprec.									-		-
Avg. Accum. Def Tax									-		-
Avg. Accum. Def ITC									-		-
Avg. Net Utility Plant	-	-	-	-	-	-	-	-	-	-	-
Operating Materials & Fuel									-		-
Deferred Programs & Investments									-		-
Misc. Deferred Credits									-		-
Working Cash	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base	-	-	-	-	-	-	-	-	-	-	-
Rate of Return											
Implied Return on Equity											
Income Taxes											
Book Revenues	-	-	-	-	-	-	-	-	-	-	-
Book Expenses	-	-	-	-	-	-	-	-	-	-	-
Interest @ Weighted Cost of Debt	-	-	-	-	-	-	-	-	-	-	-
Production Deduction									-		-
Temporary Sch M Differences									-		-
Permanent M Differences									-		-
State Taxable Income	-	-	-	-	-	-	-	-	-	-	-
State Income Tax	-	-	-	-	-	-	-	-	-	-	-
State Tax Credit									-		-
Net State Income Tax	-	-	-	-	-	-	-	-	-	-	-
Federal Taxable Income	-	-	-	-	-	-	-	-	-	-	-
Fed Tax @ 35%	-	-	-	-	-	-	-	-	-	-	-
Federal Tax Credits									-		-
Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-
Excess Deferred Income Tax Reversal (ARAM)	-	-	-	-	-	-	-	-	-	-	-
Total Income Tax	-	-	-	-	-	-	-	-	-	-	-

Portland General Electric
UE-394, 2022 Test Year
Stipulated Adjustments
($000)

	Prod. Cost	Trans. Cost	Distr. Cost	Ancillary Services	Metering Cost	Billing Cost	Other Consumer Cost	PGE Regulated Rev Req	Retail	Check Total	Control	
Sales to Consumers	-	-	-	-	-	-	-	-	-	-	-	
Other Revenues	165	-	-	-	-	-	-	165	-	165	165	
Total Operating Revenues	165	-	-	-	-	-	-	165	-	165	165	-
Net Variable Power Cost	32,227	-	-	-	-	-	-	32,227	-	32,227	32,227	-
Fixed Plant Cost	-	-	-	-	-	-	-	-	-	-	-	-
Transmission O&M	-	-	-	-	-	-	-	-	-	-	-	-
Distribution O&M	-	-	(6,920)	-	-	-	-	(6,920)	-	(6,920)	(6,920)	-
Total Fixed O&M	-	-	(6,920)	-	-	-	-	(6,920)	-	(6,920)	(6,920)	-
Customer Accounts	-	-	-	-	-	-	-	-	-	-	-	-
Uncollectibles per Rev Req Model	-	-	-	-	-	-	-	-	-	-	-	-
Customer Service & Sales	-	-	-	-	-	-	-	-	-	-	-	-
OPUC Fee	-	-	-	-	-	-	-	-	-	-	-	-
Admin. & General	(740)	(135)	(1,685)	-	(30)	(108)	(657)	(3,355)	-	(3,355)	(3,355)	0
Other O&M	(740)	(135)	(1,685)	-	(30)	(108)	(657)	(3,355)	-	(3,355)	(3,355)	0
Total Operating & Maintenance	31,487	(135)	(8,605)	-	(30)	(108)	(657)	21,952	-	21,952	21,952	0
												-
Depreciation & Amortization	12,158	(830)	(15,054)	-	(38)	(137)	(827)	(4,728)	(7)	(4,735)	(4,735)	(0)
Other Taxes	2,753	346	2,883	-	25	151	509	6,667	-	6,667	6,667	-
Franchise Fee	-	-	-	-	-	-	-	-	-	-	-	-
Income Taxes	(11,210)	189	5,617	-	12	26	268	(5,099)	2	(5,097)	(5,097)	(0)
Total Oper. Expenses & Taxes	35,187	(430)	(15,160)	-	(31)	(68)	(707)	18,792	(5)	18,787	18,787	0
Utility Operating Income	(35,022)	430	15,160	-	31	68	707	(18,627)	5	(18,622)	(18,622)	(0)
Average Rate Base												
Avg. Gross Plant	(142,904)	(2,117)	(18,797)	-	(16)	(58)	(516)	(164,407)	-	(164,407)	(164,407)	0
Avg. Accum. Deprec.	12,173	(1,119)	(15,084)	-	(33)	(121)	(733)	(4,918)	(6)	(4,924)	(4,924)	(0)
Avg. Accum. Def Tax	2,069	1,313	8,828	-	97	277	1,488	14,072	2	14,075	14,075	(0)
Avg. Accum. Def ITC	-	-	-	-	-	-	-	-	-	-	-	-
Avg. Net Utility Plant	(157,145)	(2,310)	(12,541)	-	(80)	(214)	(1,271)	(173,561)	4	(173,557)	(173,557)	0
Operating Materials & Fuel	-	-	-	-	-	-	-	-	-	-	-	-
Deferred Programs & Investments	-	-	-	-	-	-	-	-	-	-	-	-
Misc. Deferred Credits	-	-	-	-	-	-	-	-	-	-	-	-
Working Cash	1,369	(17)	(590)	-	(1)	(3)	(28)	731	(0)	731	731	0
Average Rate Base	(155,776)	(2,327)	(13,131)	-	(81)	(216)	(1,298)	(172,830)	3	(172,826)	(172,826)	0
Rate of Return												
Implied Return on Equity												
Income Taxes												
Book Revenues	165	-	-	-	-	-	-	165	-	165	165	-
Book Expenses	46,398	(618)	(20,777)	-	(43)	(94)	(975)	23,891	(7)	23,884	23,884	0
Interest @ Weighted Cost of Debt	(3,213)	(48)	(271)	-	(2)	(4)	(27)	(3,565)	0	(3,565)	(3,565)	0
Production Deduction	-	-	-	-	-	-	-	-	-	-	-	-
Temporary Sch M Differences	(2,333)	(1,130)	(10,517)	-	(28)	(103)	(624)	(14,736)	(5)	(14,741)	(14,741)	(0)
Permanent M Differences	(1,499)	(33)	245	-	0	2	10	(1,276)	0	(1,276)	(1,276)	(0)
State Taxable Income	(39,187)	1,829	31,320	-	73	200	1,616	(4,149)	12	(4,138)	(4,138)	(0)
State Income Tax	(2,976)	139	2,379	-	6	15	123	(315)	1	(314)	(314)	(0)
State Tax Credit	-	-	-	-	-	-	-	-	-	-	-	-
Net State Income Tax	(2,976)	139	2,379	-	6	15	123	(315)	1	(314)	(314)	(0)
Federal Taxable Income	(36,211)	1,690	28,942	-	67	185	1,493	(3,834)	11	(3,823)	(3,823)	(0)
Fed Tax @ 35%	(7,604)	355	6,078	-	14	39	314	(805)	2	(803)	(803)	(0)
											-	
Federal Tax Credits	-	-	-	-	-	-	-	-	-	-	-	-
Deferred Taxes	(630)	(305)	(2,840)	-	(8)	(28)	(168)	(3,979)	(1)	(3,980)	(3,980)	(0)
Excess Deferred Income Tax Reversal (ARAM)	-	-	-	-	-	-	-	-	-	-	-	-
Total Income Tax	(11,210)	189	5,617	-	12	26	268	(5,099)	2	(5,097)	(5,097)	(0)

Portland General Electric
UE-394, 2022 Test Year
Stipulated Adjustments
($000)

		0	0	0	0	0	0	0	0	0	0	0	0	0
	NVPC	S-3	S-4	S-6	S-12 / A-24 / C-3	A-5	A-6	A-7	A-11	A-18	Portion of S-23	A-26	C-4	-8, S-9, S-10 Bundl
	Adj / Updates	ExcitationSystem	eaverModernization	OCAT	Level IIIAccrual	ctors' Def Compens	D&O Ins	Directors' Expenses	R&D	ADIT-Incentives	IOC	Trojan Sch. 136	ampgoundRevenue	Bundled Adjjustmen
Sales to Consumers	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Revenues	-	-	-	-	-	-	-	-	-	-	-	-	165	-
Total Operating Revenues	-	-	-	-	-	-	-	-	-	-	-	-	165	-
Net Variable Power Cost	32,227	-	-	-	-	-	-	-	-	-	-	-	-	-
Fixed Plant Cost	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Transmission O&M	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Distribution O&M	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Fixed O&M	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Uncollectibles per Rev Req Model	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Customer Service & Sales	-	-	-	-	-	-	-	-	-	-	-	-	-	-
OPUC Fee	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Admin. & General	-	-	-	-	-	(45)	(22)	(33)	-	-	-	-	-	(154)
Other O&M	-	-	-	-	-	(45)	(22)	(33)	-	-	-	-	-	(154)
Total Operating & Maintenance	32,227	-	-	-	-	(45)	(22)	(33)	-	-	-	-	-	(154)
Depreciation & Amortization	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Taxes	-	-	-	4,461	-	-	-	-	-	-	-	-	-	-
Franchise Fee	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Income Taxes	(8,706)	-	57	(1,205)	-	12	6	9	-	7	16	-	45	42
Total Oper. Expenses & Taxes	23,521	-	57	3,256	-	(33)	(16)	(24)	-	7	16	-	45	(113)
Utility Operating Income	(23,521)	-	(57)	(3,256)	-	33	16	24	-	(7)	(16)	-	120	113
Average Rate Base														
Avg. Gross Plant	-	-	(10,172)	-	-	-	-	-	-	-	(2,847)	-	-	-
Avg. Accum. Deprec.	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Avg. Accum. Def Tax	-	-	-	-	-	-	-	-	-	1,271	-	-	-	-
Avg. Accum. Def ITC	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Avg. Net Utility Plant	-	-	(10,172)	-	-	-	-	-	-	(1,271)	(2,847)	-	-	-
Operating Materials & Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Deferred Programs & Investments	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Misc. Deferred Credits	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Working Cash	915	-	2	127	-	(1)	(1)	(1)	-	0	1	-	2	(4)
Average Rate Base	915	-	(10,170)	127	-	(1)	(1)	(1)	-	(1,270)	(2,846)	-	2	(4)
Rate of Return														
Implied Return on Equity														
Income Taxes														
Book Revenues	-	-	-	-	-	-	-	-	-	-	-	-	165	-
Book Expenses	32,227	-	-	4,461	-	(45)	(22)	(33)	-	-	-	-	-	(154)
Interest @ Weighted Cost of Debt	19	-	(210)	3	-	(0)	(0)	(0)	-	(26)	(59)	-	0	(0)
Production Deduction	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Temporary Sch M Differences	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Permanent M Differences	-	-	-	-	-	-	-	-	-	-	-	-	-	-
State Taxable Income	(32,246)	-	210	(4,464)	-	45	22	33	-	26	59	-	165	154
State Income Tax	(2,449)	-	16	(339)	-	3	2	3	-	2	4	-	13	12
State Tax Credit	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net State Income Tax	(2,449)	-	16	(339)	-	3	2	3	-	2	4	-	13	12
Federal Taxable Income	(29,797)	-	194	(4,125)	-	41	20	31	-	24	54	-	152	143
Fed Tax @ 35%	(6,257)	-	41	(866)	-	9	4	6	-	5	11	-	32	30
Federal Tax Credits	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Excess Deferred Income Tax Reversal (ARAM)										-				
Total Income Tax	(8,706)	-	57	(1,205)	-	12	6	9	-	7	16	-	45	42

0 -22, A-20, A-23 Bundl Bundled Adjjustment	0 12/13/21 Proposal Remove Faraday	0 0 Global to $10M	0 0 epreciationto UI	0 0 Blank-18	0 0 Blank-19	0 0 Blank-20	0 0 Blank 21	0 0 Blank 22	0 0 Blank 23	0 0 Blank 24	0 0 Blank 25	0 0 Blank 26	0 0 Blank 27	0 0 Blank 28	0 0 Blank 29	0 0 Blank 30	0 0 Blank 31
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
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-	-	(486)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	(486)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	(486)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	(5,121)	-	17,279	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	(1,708)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
58	2,479	131	(4,161)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
58	(4,351)	(354)	13,119	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(58)	4,351	354	(13,119)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(10,500)	(119,385)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	(5,121)	-	17,294	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	(381)	-	1,179	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(10,500)	(113,882)	-	(18,473)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	(169)	(14)	510	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(10,498)	(114,052)	(14)	(17,963)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	(6,830)	(486)	17,279	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(217)	(2,352)	(0)	(370)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	(2,333)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	(1,499)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
217	9,182	486	(13,076)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	697	37	(993)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	697	37	(993)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
200	8,485	449	(12,083)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
42	1,782	94	(2,537)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	(630)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
58	2,479	131	(4,161)	-	-	-	-	-	-	-	-	-	-	-	-	-	-

0	0	0	0	0	0	0	0	0	0	
0	0	0	0	0	0	0	0	0	0	Total
Blank 32	Blank 33	Blank 34	Blank 35	Blank 36	Blank 37	Blank 38	Blank 39	Blank 40	Blank 41	Adjustments
-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	165
-	-	-	-	-	-	-	-	-	-	165
-	-	-	-	-	-	-	-	-	-	32,227
-	-	-	-	-	-	-	-	-	-	-
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-	-	-	-	-	-	-	-	-	-	(740)
-	-	-	-	-	-	-	-	-	-	31,487
-	-	-	-	-	-	-	-	-	-	12,158
-	-	-	-	-	-	-	-	-	-	2,753
-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	(11,210)
-	-	-	-	-	-	-	-	-	-	35,187
-	-	-	-	-	-	-	-	-	-	(35,022)
-	-	-	-	-	-	-	-	-	-	(142,904)
-	-	-	-	-	-	-	-	-	-	12,173
-	-	-	-	-	-	-	-	-	-	2,069
-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	(157,145)
-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	1,369
-	-	-	-	-	-	-	-	-	-	(155,776)
-	-	-	-	-	-	-	-	-	-	165
-	-	-	-	-	-	-	-	-	-	46,398
-	-	-	-	-	-	-	-	-	-	(3,213)
-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	(2,333)
-	-	-	-	-	-	-	-	-	-	(1,499)
-	-	-	-	-	-	-	-	-	-	(39,187)
-	-	-	-	-	-	-	-	-	-	(2,976)
-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	(2,976)
-	-	-	-	-	-	-	-	-	-	(36,211)
-	-	-	-	-	-	-	-	-	-	(7,604)
-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	(630)
										-
-	-	-	-	-	-	-	-	-	-	(11,210)

Portland General Electric
UE-394, 2022 Test Year
Stipulated Adjustments
($000)

		0	0	0	0	0	0	0	0	0	0	0	0	0
	NVPC Adj / Updates	S-3 ExcitationSystem	S-4 eaverModernization	S-6 OCAT	S-12 / A-24 / C-3 Level IIIAccrual	A-5 ctors' Def Compens	A-6 D&O Ins	A-7 Directors' Expenses	A-11 R&D	A-18 ADIT-Incentives	Portion of S-23 IOC	A-26 Trojan Sch. 136	C-4 ampgoundRevenue	-8, S-9, S-10 Bundl Bundled Adjjustmen
Sales to Consumers	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Operating Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Variable Power Cost	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Fixed Plant Cost	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Transmission O&M	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Distribution O&M	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Fixed O&M	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Uncollectibles per Rev Req Model	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Customer Service & Sales	-	-	-	-	-	-	-	-	-	-	-	-	-	-
OPUC Fee	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Admin. & General	-	-	-	-	-	(8)	(4)	(6)	-	-	-	-	-	(28)
Other O&M	-	-	-	-	-	(8)	(4)	(6)	-	-	-	-	-	(28)
Total Operating & Maintenance	-	-	-	-	-	(8)	(4)	(6)	-	-	-	-	-	(28)
Depreciation & Amortization	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Taxes	-	-	-	346	-	-	-	-	-	-	-	-	-	-
Franchise Fee	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Income Taxes	-	-	-	(94)	-	2	1	2	-	1	12	-	-	8
Total Oper. Expenses & Taxes	-	-	-	253	-	(6)	(3)	(4)	-	1	12	-	-	(21)
Utility Operating Income	-	-	-	(253)	-	6	3	4	-	(1)	(12)	-	-	21
Average Rate Base														
Avg. Gross Plant	-	-	-	-	-	-	-	-	-	-	(2,117)	-	-	-
Avg. Accum. Deprec.	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Avg. Accum. Def Tax	-	-	-	-	-	-	-	-	-	231	-	-	-	-
Avg. Accum. Def ITC	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Avg. Net Utility Plant	-	-	-	-	-	-	-	-	-	(231)	(2,117)	-	-	-
Operating Materials & Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Deferred Programs & Investments	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Misc. Deferred Credits	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Working Cash	-	-	-	10	-	(0)	(0)	(0)	-	0	0	-	-	(1)
Average Rate Base	-	-	-	10	-	(0)	(0)	(0)	-	(231)	(2,116)	-	-	(1)
Rate of Return														
Implied Return on Equity														
Income Taxes														
Book Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Book Expenses	-	-	-	346	-	(8)	(4)	(6)	-	-	-	-	-	(28)
Interest @ Weighted Cost of Debt	-	-	-	0	-	(0)	(0)	(0)	-	(5)	(44)	-	-	(0)
Production Deduction	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Temporary Sch M Differences	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Permanent M Differences	-	-	-	-	-	-	-	-	-	-	-	-	-	-
State Taxable Income	-	-	-	(346)	-	8	4	6	-	5	44	-	-	28
State Income Tax	-	-	-	(26)	-	1	0	0	-	0	3	-	-	2
State Tax Credit	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net State Income Tax	-	-	-	(26)	-	1	0	0	-	0	3	-	-	2
Federal Taxable Income	-	-	-	(320)	-	8	4	6	-	4	40	-	-	26
Fed Tax @ 35%	-	-	-	(67)	-	2	1	1	-	1	8	-	-	5
Federal Tax Credits	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Excess Deferred Income Tax Reversal (ARAM)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Income Tax	-	-	-	(94)	-	2	1	2	-	1	12	-	-	8

0 -22, A-20, A-23 Bundl Bundled Adjjustment	0 12/13/21 Proposal Remove Faraday	0 0 Global to $10MM	0 0 epreciationto UI	0 0 Blank-18	0 0 Blank-19	0 0 Blank-20	0 0 Blank 21	0 0 Blank 22	0 0 Blank 23	0 0 Blank 24	0 0 Blank 25	0 0 Blank 26	0 0 Blank 27	0 0 Blank 28	0 0 Blank 29	0 0 Blank 30
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-	-	(65)	(597)	-	-	-	-	-	-	-	-	-	-	-	-	-
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-	-	88	1,992	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	7	151	-	-	-	-	-	-	-	-	-	-	-	-	-
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-	-	7	151	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	82	1,841	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	17	387	-	-	-	-	-	-	-	-	-	-	-	-	-
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-	-	24	233	-	-	-	-	-	-	-	-	-	-	-	-	-

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0	0	0	0	0	0	0	0	0	0	0	Total
Blank 31	Blank 32	Blank 33	Blank 34	Blank 35	Blank 36	Blank 37	Blank 38	Blank 39	Blank 40	Blank 41	Adjustments
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Portland General Electric
UE-394, 2022 Test Year
Stipulated Adjustments
($000)

		0	0	0	0	0	0	0	0	0	0	0	0	0
	NVPC	S-3	S-4	S-6	S-12 / A-24 / C-3	A-5	A-6	A-7	A-11	A-18	Portion of S-23	A-26	C-4	-8, S-9, S-10 Bundl
	Adj / Updates	ExcitationSystem	eaverModernization	OCAT	Level IIIAccrual	ctors' Def Compensa	D&O Ins	Directors' Expenses	R&D	ADIT-Incentives	IOC	Trojan Sch. 136	ampgoundRevenue	Bundled Adjjustmen
Sales to Consumers	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Operating Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Variable Power Cost	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Fixed Plant Cost	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Transmission O&M	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Distribution O&M	-	-	-	-	(6,920)	-	-	-	-	-	-	-	-	-
Total Fixed O&M	-	-	-	-	(6,920)	-	-	-	-	-	-	-	-	-
Customer Accounts	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Uncollectibles per Rev Req Model	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Customer Service & Sales	-	-	-	-	-	-	-	-	-	-	-	-	-	-
OPUC Fee	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Admin. & General	-	-	-	-	-	(102)	(50)	(75)	-	-	-	-	-	(352)
Other O&M	-	-	-	-	-	(102)	(50)	(75)	-	-	-	-	-	(352)
Total Operating & Maintenance	-	-	-	-	(6,920)	(102)	(50)	(75)	-	-	-	-	-	(352)
Depreciation & Amortization	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Taxes	-	-	-	2,883	-	-	-	-	-	-	-	-	-	-
Franchise Fee	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Income Taxes	-	2	-	(779)	1,869	28	14	20	-	16	19	-	-	95
Total Oper. Expenses & Taxes	-	2	-	2,104	(5,051)	(74)	(37)	(55)	-	16	19	-	-	(257)
Utility Operating Income	-	(2)	-	(2,104)	5,051	74	37	55	-	(16)	(19)	-	-	257
Average Rate Base														
Avg. Gross Plant	-	(350)	-	-	-	-	-	-	-	-	(3,447)	-	-	-
Avg. Accum. Deprec.	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Avg. Accum. Def Tax	-	-	-	-	-	-	-	-	-	2,894	-	-	-	-
Avg. Accum. Def ITC	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Avg. Net Utility Plant	-	(350)	-	-	-	-	-	-	-	(2,894)	(3,447)	-	-	-
Operating Materials & Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Deferred Programs & Investments	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Misc. Deferred Credits	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Working Cash	-	0	-	82	(196)	(3)	(1)	(2)	-	1	1	-	-	(10)
Average Rate Base	-	(350)	-	82	(196)	(3)	(1)	(2)	-	(2,893)	(3,446)	-	-	(10)
Rate of Return														
Implied Return on Equity														
Income Taxes														
Book Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Book Expenses	-	-	-	2,883	(6,920)	(102)	(50)	(75)	-	-	-	-	-	(352)
Interest @ Weighted Cost of Debt	-	(7)	-	2	(4)	(0)	(0)	(0)	-	(60)	(71)	-	-	(0)
Production Deduction	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Temporary Sch M Differences	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Permanent M Differences	-	-	-	-	-	-	-	-	-	-	-	-	-	-
State Taxable Income	-	7	-	(2,884)	6,924	102	50	75	-	60	71	-	-	352
State Income Tax	-	1	-	(219)	526	8	4	6	-	5	5	-	-	27
State Tax Credit	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net State Income Tax	-	1	-	(219)	526	8	4	6	-	5	5	-	-	27
Federal Taxable Income	-	7	-	(2,665)	6,398	94	46	70	-	55	66	-	-	325
Fed Tax @ 35%	-	1	-	(560)	1,344	20	10	15	-	12	14	-	-	68
Federal Tax Credits	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Excess Deferred Income Tax Reversal (ARAM)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Income Tax	-	2	-	(779)	1,869	28	14	20	-	16	19	-	-	95

0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
-22, A-20, A-23 Bundl	12/13/21 Proposal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bundled Adjustment	Remove Faraday	lobal to $10M	epreciationto UI	Blank-18	Blank-19	Blank-20	Blank 21	Blank 22	Blank 23	Blank 24	Blank 25	Blank 26	Blank 27	Blank 28	Blank 29	Blank 30
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-	-	(1,106)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	(1,106)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	(1,106)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
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-	-	382	3,950	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	(724)	(11,104)	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	724	11,104	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	(15,000)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	(15,084)	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	5,934	-	-	-	-	-	-	-	-	-	-	-	-	-
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-	-	(15,000)	9,150	-	-	-	-	-	-	-	-	-	-	-	-	-
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-	-	(28)	(432)	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	(15,028)	8,718	-	-	-	-	-	-	-	-	-	-	-	-	-
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-	-	(1,106)	(15,054)	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	(310)	180	-	-	-	-	-	-	-	-	-	-	-	-	-
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-	-	-	(10,517)	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	245	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	1,416	25,147	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	108	1,910	-	-	-	-	-	-	-	-	-	-	-	-	-
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-	-	108	1,910	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	1,309	23,237	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	275	4,880	-	-	-	-	-	-	-	-	-	-	-	-	-
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-	-	-	(2,840)	-	-	-	-	-	-	-	-	-	-	-	-	-
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-	-	382	3,950	-	-	-	-	-	-	-	-	-	-	-	-	-

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0	0	0	0	0	0	0	0	0	0	0	Total
Blank 31	Blank 32	Blank 33	Blank 34	Blank 35	Blank 36	Blank 37	Blank 38	Blank 39	Blank 40	Blank 41	Adjustments
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-	-	-	-	-	-	-	-	-	-	-	31,320
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-	-	-	-	-	-	-	-	-	-	-	5,617

Portland General Electric
UE-394, 2022 Test Year
Stipulated Adjustments
($000)

	NVPC Adj / Updates	0 S-3 ExcitationSystem	0 S-4 eaverModernization	0 S-6 OCAT	0 S-12 / A-24 / C-3 Level IIIAccrual	0 A-5 ctors' Def Compensa	0 A-6 D&O Ins	0 A-7 Directors' Expenses	0 A-11 R&D	0 A-18 ADIT-Incentives	0 Portion of S-23 IOC	0 A-26 Trojan Sch. 136	0 C-4 ampgoundRevenue	0 -8, S-9, S-10 Bundle Bundled Adjjustmen
Sales to Consumers	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Operating Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Variable Power Cost	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Fixed Plant Cost	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Transmission O&M	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Distribution O&M	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Fixed O&M	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Uncollectibles per Rev Req Model	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Customer Service & Sales	-	-	-	-	-	-	-	-	-	-	-	-	-	-
OPUC Fee	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Admin. & General	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other O&M	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Operating & Maintenance	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Depreciation & Amortization	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Franchise Fee	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Income Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Oper. Expenses & Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Utility Operating Income	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base														
Avg. Gross Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Avg. Accum. Deprec.	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Avg. Accum. Def Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Avg. Accum. Def ITC	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Avg. Net Utility Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Materials & Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Deferred Programs & Investments	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Misc. Deferred Credits	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Working Cash	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rate of Return														
Implied Return on Equity														
Income Taxes														
Book Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Book Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Interest @ Weighted Cost of Debt	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Production Deduction	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Temporary Sch M Differences	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Permanent M Differences	-	-	-	-	-	-	-	-	-	-	-	-	-	-
State Taxable Income	-	-	-	-	-	-	-	-	-	-	-	-	-	-
State Income Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
State Tax Credit	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net State Income Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Federal Taxable Income	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Fed Tax @ 35%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Federal Tax Credits	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Excess Deferred Income Tax Reversal (ARAM)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Income Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-

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-22, A-20, A-23 Bundl	12/13/21 Proposal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bundled Adjjustment	Remove Faraday	lobal to $10M	epreciationto U	Blank-18	Blank-19	Blank-20	Blank 21	Blank 22	Blank 23	Blank 24	Blank 25	Blank 26	Blank 27	Blank 28	Blank 29	Blank 30	Blank 31
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0 0 Blank 32	0 0 Blank 33	0 0 Blank 34	0 0 Blank 35	0 0 Blank 36	0 0 Blank 37	0 0 Blank 38	0 0 Blank 39	0 0 Blank 40	0 0 Blank 41	Total Adjustments
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Portland General Electric
UE-394, 2022 Test Year
Stipulated Adjustments
($000)

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	NVPC Adj / Updates	S-3 ExcitationSystem	S-4 ;eaverModernization	S-6 OCAT	S-12 / A-24 / C-3 Level IIIAccrual	A-5 ctors' Def Compens	A-6 D&O Ins	A-7 Directors' Expenses	A-11 R&D	A-18 ADIT-Incentives	Portion of S-23 IOC	A-26 Trojan Sch. 136	C-4 'ampgoundRevenue	-8, S-9, S-10 Bundl Bundled Adjustmen
Sales to Consumers	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Operating Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Variable Power Cost	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Fixed Plant Cost	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Transmission O&M	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Distribution O&M	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Fixed O&M	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Uncollectibles per Rev Req Model	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Customer Service & Sales	-	-	-	-	-	-	-	-	-	-	-	-	-	-
OPUC Fee	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Admin. & General	-	-	-	-	-	(2)	(1)	(1)	-	-	-	-	-	(6)
Other O&M	-	-	-	-	-	(2)	(1)	(1)	-	-	-	-	-	(6)
Total Operating & Maintenance	-	-	-	-	-	(2)	(1)	(1)	-	-	-	-	-	(6)
Depreciation & Amortization	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Taxes	-	-	-	25	-	-	-	-	-	-	-	-	-	-
Franchise Fee	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Income Taxes	-	-	-	(7)	-	0	0	0	-	0	0	-	-	2
Total Oper. Expenses & Taxes	-	-	-	18	-	(1)	(1)	(1)	-	0	0	-	-	(5)
Utility Operating Income	-	-	-	(18)	-	1	1	1	-	(0)	(0)	-	-	5
Average Rate Base														
Avg. Gross Plant	-	-	-	-	-	-	-	-	-	-	(16)	-	-	-
Avg. Accum. Deprec.	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Avg. Accum. Def Tax	-	-	-	-	-	-	-	-	-	51	-	-	-	-
Avg. Accum. Def ITC	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Avg. Net Utility Plant	-	-	-	-	-	-	-	-	-	(51)	(16)	-	-	-
Operating Materials & Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Deferred Programs & Investments	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Misc. Deferred Credits	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Working Cash	-	-	-	1	-	(0)	(0)	(0)	-	0	0	-	-	(0)
Average Rate Base	-	-	-	1	-	(0)	(0)	(0)	-	(51)	(16)	-	-	(0)
Rate of Return														
Implied Return on Equity														
Income Taxes														
Book Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Book Expenses	-	-	-	25	-	(2)	(1)	(1)	-	-	-	-	-	(6)
Interest @ Weighted Cost of Debt	-	-	-	0	-	(0)	(0)	(0)	-	(1)	(0)	-	-	(0)
Production Deduction	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Temporary Sch M Differences	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Permanent M Differences	-	-	-	-	-	-	-	-	-	-	-	-	-	-
State Taxable Income	-	-	-	(25)	-	2	1	1	-	1	0	-	-	6
State Income Tax	-	-	-	(2)	-	0	0	0	-	0	0	-	-	0
State Tax Credit	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net State Income Tax	-	-	-	(2)	-	0	0	0	-	0	0	-	-	0
Federal Taxable Income	-	-	-	(23)	-	2	1	1	-	1	0	-	-	6
Fed Tax @ 35%	-	-	-	(5)	-	0	0	0	-	0	0	-	-	1
Federal Tax Credits	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Excess Deferred Income Tax Reversal (ARAM)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Income Tax	-	-	-	(7)	-	0	0	0	-	0	0	-	-	2

0 -22, A-20, A-23 Bundl Bundled Adjustment	0 12/13/21 Proposal Remove Faraday	0 0 ilobal to $10M	0 0 epreciationto UI	0 0 Blank-18	0 0 Blank-19	0 0 Blank-20	0 0 Blank 21	0 0 Blank 22	0 0 Blank 23	0 0 Blank 24	0 0 Blank 25	0 0 Blank 26	0 0 Blank 27	0 0 Blank 28	0 0 Blank 29	0 0 Blank 30	0 0 Blank 31
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-	-	(20)	(38)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	(0)	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
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Blank 32	Blank 33	Blank 34	Blank 35	Blank 36	Blank 37	Blank 38	Blank 39	Blank 40	Blank 41	Adjustments
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Portland General Electric
UE-394, 2022 Test Year
Stipulated Adjustments
($000)

	NVPC Adj / Updates	0 S-3 ExcitationSystem	0 S-4 ;eaverModernization	0 S-6 OCAT	0 S-12 / A-24 / C-3 Level IIIAccrual	0 A-5 :ctors' Def Compensa	0 A-6 D&O Ins	0 A-7 Directors' Expenses	0 A-11 R&D	0 A-18 ADIT-Incentives	0 Portion of S-23 IOC	0 A-26 Trojan Sch. 136	0 C-4 ampgoundRevenue	0 -8, S-9, S-10 Bundl Bundled Adjustmen
Sales to Consumers	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Operating Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Variable Power Cost	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Fixed Plant Cost	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Transmission O&M	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Distribution O&M	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Fixed O&M	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Uncollectibles per Rev Req Model	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Customer Service & Sales	-	-	-	-	-	-	-	-	-	-	-	-	-	-
OPUC Fee	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Admin. & General	-	-	-	-	-	(7)	(3)	(5)	-	-	-	-	-	(23)
Other O&M	-	-	-	-	-	(7)	(3)	(5)	-	-	-	-	-	(23)
Total Operating & Maintenance	-	-	-	-	-	(7)	(3)	(5)	-	-	-	-	-	(23)
Depreciation & Amortization	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Taxes	-	-	-	151	-	-	-	-	-	-	-	-	-	-
Franchise Fee	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Income Taxes	-	-	-	(41)	-	2	1	1	-	1	0	-	-	6
Total Oper. Expenses & Taxes	-	-	-	110	-	(5)	(2)	(4)	-	1	0	-	-	(17)
Utility Operating Income	-	-	-	(110)	-	5	2	4	-	(1)	(0)	-	-	17
Average Rate Base														
Avg. Gross Plant	-	-	-	-	-	-	-	-	-	-	(58)	-	-	-
Avg. Accum. Deprec.	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Avg. Accum. Def Tax	-	-	-	-	-	-	-	-	-	186	-	-	-	-
Avg. Accum. Def ITC	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Avg. Net Utility Plant	-	-	-	-	-	-	-	-	-	(186)	(58)	-	-	-
Operating Materials & Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Deferred Programs & Investments	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Misc. Deferred Credits	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Working Cash	-	-	-	4	-	(0)	(0)	(0)	-	0	0	-	-	(1)
Average Rate Base	-	-	-	4	-	(0)	(0)	(0)	-	(186)	(58)	-	-	(1)
Rate of Return														
Implied Return on Equity														
Income Taxes														
Book Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Book Expenses	-	-	-	151	-	(7)	(3)	(5)	-	-	-	-	-	(23)
Interest @ Weighted Cost of Debt	-	-	-	0	-	(0)	(0)	(0)	-	(4)	(1)	-	-	(0)
Production Deduction	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Temporary Sch M Differences	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Permanent M Differences	-	-	-	-	-	-	-	-	-	-	-	-	-	-
State Taxable Income	-	-	-	(151)	-	7	3	5	-	4	1	-	-	23
State Income Tax	-	-	-	(11)	-	0	0	0	-	0	0	-	-	2
State Tax Credit	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net State Income Tax	-	-	-	(11)	-	0	0	0	-	0	0	-	-	2
Federal Taxable Income	-	-	-	(140)	-	6	3	4	-	4	1	-	-	21
Fed Tax @ 35%	-	-	-	(29)	-	1	1	1	-	1	0	-	-	4
Federal Tax Credits	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Excess Deferred Income Tax Reversal (ARAM)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Income Tax	-	-	-	(41)	-	2	1	1	-	1	0	-	-	6

0 -22, A-20, A-23 Bundl Bundled Adjustment	0 12/13/21 Proposal Remove Faraday	0 0 Global to $10M	0 0 epreciationto UI	0 0 Blank-18	0 0 Blank-19	0 0 Blank-20	0 0 Blank 21	0 0 Blank 22	0 0 Blank 23	0 0 Blank 24	0 0 Blank 25	0 0 Blank 26	0 0 Blank 27	0 0 Blank 28	0 0 Blank 29	0 0 Blank 30	0 0 Blank 31
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Blank 32	Blank 33	Blank 34	Blank 35	Blank 36	Blank 37	Blank 38	Blank 39	Blank 40	Blank 41	Adjustments
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-	-	-	-	-	-	-	-	-	-	(28)
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-	-	-	-	-	-	-	-	-	-	26

Portland General Electric
UE-394, 2022 Test Year
Stipulated Adjustments
($000)

		0	0	0	0	0	0	0	0	0	0	0	0	0
	NVPC Adj / Updates	S-3 ExcitationSystem	S-4 ieaverModernization	S-6 OCAT	S-12 / A-24 / C-3 Level IIIAccrual	A-5 ctors' Def Compens	A-6 D&O Ins	A-7 Directors' Expenses	A-11 R&D	A-18 ADIT-Incentives	Portion of S-23 IOC	A-26 Trojan Sch. 136	C-4 ampgoundRevenue	-8, S-9, S-10 Bundl Bundled Adjjustmen
Sales to Consumers	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Operating Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Variable Power Cost	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Fixed Plant Cost	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Transmission O&M	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Distribution O&M	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Fixed O&M	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Uncollectibles per Rev Req Model	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Customer Service & Sales	-	-	-	-	-	-	-	-	-	-	-	-	-	-
OPUC Fee	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Admin. & General	-	-	-	-	-	(40)	(20)	(29)	-	-	-	-	-	(137)
Other O&M	-	-	-	-	-	(40)	(20)	(29)	-	-	-	-	-	(137)
Total Operating & Maintenance	-	-	-	-	-	(40)	(20)	(29)	-	-	-	-	-	(137)
Depreciation & Amortization	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Taxes	-	-	-	509	-	-	-	-	-	-	-	-	-	-
Franchise Fee	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Income Taxes	-	-	-	(138)	-	11	5	8	-	6	3	-	-	37
Total Oper. Expenses & Taxes	-	-	-	372	-	(29)	(14)	(21)	-	6	3	-	-	(100)
Utility Operating Income	-	-	-	(372)	-	29	14	21	-	(6)	(3)	-	-	100
Average Rate Base														
Avg. Gross Plant	-	-	-	-	-	-	-	-	-	-	(516)	-	-	-
Avg. Accum. Deprec.	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Avg. Accum. Def Tax	-	-	-	-	-	-	-	-	-	1,128	-	-	-	-
Avg. Accum. Def ITC	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Avg. Net Utility Plant	-	-	-	-	-	-	-	-	-	(1,128)	(516)	-	-	-
Operating Materials & Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Deferred Programs & Investments	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Misc. Deferred Credits	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Working Cash	-	-	-	14	-	(1)	(1)	(1)	-	0	0	-	-	(4)
Average Rate Base	-	-	-	14	-	(1)	(1)	(1)	-	(1,127)	(516)	-	-	(4)
Rate of Return														
Implied Return on Equity														
Income Taxes														
Book Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Book Expenses	-	-	-	509	-	(40)	(20)	(29)	-	-	-	-	-	(137)
Interest @ Weighted Cost of Debt	-	-	-	0	-	(0)	(0)	(0)	-	(23)	(11)	-	-	(0)
Production Deduction	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Temporary Sch M Differences	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Permanent M Differences	-	-	-	-	-	-	-	-	-	-	-	-	-	-
State Taxable Income	-	-	-	(510)	-	40	20	29	-	23	11	-	-	137
State Income Tax	-	-	-	(39)	-	3	1	2	-	2	1	-	-	10
State Tax Credit	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net State Income Tax	-	-	-	(39)	-	3	1	2	-	2	1	-	-	10
Federal Taxable Income	-	-	-	(471)	-	37	18	27	-	21	10	-	-	127
Fed Tax @ 35%	-	-	-	(99)	-	8	4	6	-	5	2	-	-	27
Federal Tax Credits	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Excess Deferred Income Tax Reversal (ARAM)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Income Tax	-	-	-	(138)	-	11	5	8	-	6	3	-	-	37

0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
-22, A-20, A-23 Bundl	12/13/21 Proposal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bundled Adjustment	Remove Faraday	ilobal to $10M	epreciationto U	Blank-18	Blank-19	Blank-20	Blank 21	Blank 22	Blank 23	Blank 24	Blank 25	Blank 26	Blank 27	Blank 28	Blank 29	Blank 30	Blank 31
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-	-	-	(827)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
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-	-	(12)	349	-	-	-	-	-	-	-	-	-	-	-	-	-	-
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-	-	431	1,434	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	33	109	-	-	-	-	-	-	-	-	-	-	-	-	-	-
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-	-	33	109	-	-	-	-	-	-	-	-	-	-	-	-	-	-
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-	-	-	(168)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
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-	-	116	219	-	-	-	-	-	-	-	-	-	-	-	-	-	-

0 0 Blank 32	0 0 Blank 33	0 0 Blank 34	0 0 Blank 35	0 0 Blank 36	0 0 Blank 37	0 0 Blank 38	0 0 Blank 39	0 0 Blank 40	0 0 Blank 41	Total Adjustments
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-	-	-	-	-	-	-	-	-	-	(168)
-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	268

Portland General Electric
UE-394, 2022 Test Year
Stipulated Adjustments
($000)

		0	0	0	0	0	0	0	0	0	0	0	0	0
	NVPC	S-3	S-4	S-6	S-12 / A-24 / C-3	A-5	A-6	A-7	A-11	A-18	Portion of S-23	A-26	C-4	-8, S-9, S-10 Bundl
	Adj / Updates	ExcitationSystem	:eaverModernization	OCAT	Level IIIAccrual	:ctors' Def Compens:	D&O Ins	Directors' Expenses	R&D	ADIT-Incentives	IOC	Trojan Sch. 136	:ampgoundRevenue	Bundled Adjjustmen
Sales to Consumers	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Operating Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Variable Power Cost	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Fixed Plant Cost	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Transmission O&M	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Distribution O&M	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Fixed O&M	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Customer Accounts	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Uncollectibles per Rev Req Model	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Customer Service & Sales	-	-	-	-	-	-	-	-	-	-	-	-	-	-
OPUC Fee	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Admin. & General	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other O&M	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Operating & Maintenance	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Depreciation & Amortization	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Franchise Fee	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Income Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Oper. Expenses & Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Utility Operating Income	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base														
Avg. Gross Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Avg. Accum. Deprec.	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Avg. Accum. Def Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Avg. Accum. Def ITC	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Avg. Net Utility Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Materials & Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Deferred Programs & Investments	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Misc. Deferred Credits	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Working Cash	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Average Rate Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rate of Return														
Implied Return on Equity														
Income Taxes														
Book Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Book Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Interest @ Weighted Cost of Debt	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Production Deduction	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Temporary Sch M Differences	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Permanent M Differences	-	-	-	-	-	-	-	-	-	-	-	-	-	-
State Taxable Income	-	-	-	-	-	-	-	-	-	-	-	-	-	-
State Income Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
State Tax Credit	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net State Income Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Federal Taxable Income	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Fed Tax @ 35%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Federal Tax Credits	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Excess Deferred Income Tax Reversal (ARAM)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Income Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-

0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
-22, A-20, A-23 Bundl	12/13/21 Proposal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bundled Adjjustment	Remove Faraday	ilobal to $10M	epreciationto UI	Blank-18	Blank-19	Blank-20	Blank 21	Blank 22	Blank 23	Blank 24	Blank 25	Blank 26	Blank 27	Blank 28	Blank 29	Blank 30	Blank 31
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Portland General Electric
UE-394, 2022 Test Year
Stipulated Adjustments
($000)

	NVPC Adj / Updates	0 S-3 ExcitationSystem	0 S-4 3eaverModernization	0 S-6 OCAT	0 S-12 / A-24 / C-3 Level IIIAccrual	0 A-5 ectors' Def Compensa	0 A-6 D&O Ins	0 A-7 Directors' Expenses	0 A-11 R&D	0 A-18 ADIT-Incentives	0 Portion of S-23 IOC	0 A-26 Trojan Sch. 136	0 0 C-4 CampgoundRevenue	0 0 ;-8, S-9, S-10 Bundl Bundled Adjustmen
Sales to Consumers	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Revenues	-	-	-	-	-	-	-	-	-	-	-	-	165	-
Total Operating Revenues	-	-	-	-	-	-	-	-	-	-	-	-	165	-
Net Variable Power Cost	32,227	-	-	-	-	-	-	-	-	-	-	-	-	-
Fixed Plant Cost	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Transmission O&M	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Distribution O&M	-	-	-	-	(6,920)	-	-	-	-	-	-	-	-	-
Total Fixed O&M	-	-	-	-	(6,920)	-	-	-	-	-	-	-	-	-
Customer Accounts	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Uncollectibles per Rev Req Model	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Customer Service & Sales	-	-	-	-	-	-	-	-	-	-	-	-	-	-
OPUC Fee	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Admin. & General	-	-	-	-	-	(203)	(100)	(150)	-	-	-	-	-	(700)
Other O&M	-	-	-	-	-	(203)	(100)	(150)	-	-	-	-	-	(700)
Total Operating & Maintenance	32,227	-	-	-	(6,920)	(203)	(100)	(150)	-	-	-	-	-	(700)
Depreciation & Amortization	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Taxes	-	-	-	8,375	-	-	-	-	-	-	-	-	-	-
Franchise Fee	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Income Taxes	(8,706)	2	57	(2,263)	1,869	55	27	41	-	32	50	-	45	189
Total Oper. Expenses & Taxes	23,521	2	57	6,112	(5,051)	(148)	(73)	(109)	-	32	50	-	45	(511)
Utility Operating Income	(23,521)	(2)	(57)	(6,112)	5,051	148	73	109	-	(32)	(50)	-	120	511
Average Rate Base														
Avg. Gross Plant	-	(350)	(10,172)	-	-	-	-	-	-	-	(9,000)	-	-	-
Avg. Accum. Deprec.	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Avg. Accum. Def Tax	-	-	-	-	-	-	-	-	-	5,761	-	-	-	-
Avg. Accum. Def ITC	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Avg. Net Utility Plant	-	(350)	(10,172)	-	-	-	-	-	-	(5,761)	(9,000)	-	-	-
Operating Materials & Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Deferred Programs & Investments	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Misc. Deferred Credits	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Working Cash	915	0	2	238	(196)	(6)	(3)	(4)	-	1	2	-	2	(20)
Average Rate Base	915	(350)	(10,170)	238	(196)	(6)	(3)	(4)	-	(5,760)	(8,998)	-	2	(20)
Rate of Return														
Implied Return on Equity														
Income Taxes														
Book Revenues	-	-	-	-	-	-	-	-	-	-	-	-	165	-
Book Expenses	32,227	-	-	8,375	(6,920)	(203)	(100)	(150)	-	-	-	-	-	(700)
Interest @ Weighted Cost of Debt	19	(7)	(210)	5	(4)	(0)	(0)	(0)	-	(119)	(186)	-	0	(0)
Production Deduction	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Temporary Sch M Differences	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Permanent M Differences	-	-	-	-	-	-	-	-	-	-	-	-	-	-
State Taxable Income	(32,246)	7	210	(8,380)	6,924	203	100	150	-	119	186	-	165	700
State Income Tax	(2,449)	1	16	(636)	526	15	8	11	-	9	14	-	13	53
State Tax Credit	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net State Income Tax	(2,449)	1	16	(636)	526	15	8	11	-	9	14	-	13	53
Federal Taxable Income	(29,797)	7	194	(7,744)	6,398	188	92	139	-	110	171	-	152	647
Fed Tax @ 35%	(6,257)	1	41	(1,626)	1,344	39	19	29	-	23	36	-	32	136
Federal Tax Credits	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Deferred Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Excess Deferred Income Tax Reversal (ARAM)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Income Tax	(8,706)	2	57	(2,263)	1,869	55	27	41	-	32	50	-	45	189

0																	
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
22, A-20, A-23 Bund	12/13/21 Proposal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bundled Adjjustment	Remove Faraday	Global to $10MM	Depreciationto UM	Blank-18	Blank-19	Blank-20	Blank 21	Blank 22	Blank 23	Blank 24	Blank 25	Blank 26	Blank 27	Blank 28	Blank 29	Blank 30	Blank 31
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
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-	-	(2,202)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	(2,202)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	(2,202)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	(5,121)	-	387	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	(1,708)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
58	2,479	678	289	-	-	-	-	-	-	-	-	-	-	-	-	-	-
58	(4,351)	(1,524)	676	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(58)	4,351	1,524	(676)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(10,500)	(119,385)	(15,000)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	(5,121)	-	197	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	(381)	-	8,694	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(10,500)	(113,882)	(15,000)	(8,892)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
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2	(169)	(59)	26	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(10,498)	(114,052)	(15,059)	(8,865)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
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-	(6,830)	(2,202)	387	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(217)	(2,352)	(311)	(183)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
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-	-	-	(14,741)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	(1,276)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
217	9,182	2,513	15,813	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	697	191	1,201	-	-	-	-	-	-	-	-	-	-	-	-	-	-
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16	697	191	1,201	-	-	-	-	-	-	-	-	-	-	-	-	-	-
200	8,485	2,322	14,612	-	-	-	-	-	-	-	-	-	-	-	-	-	-
42	1,782	488	3,068	-	-	-	-	-	-	-	-	-	-	-	-	-	-
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-	-	-	(3,980)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
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58	2,479	678	289	-	-	-	-	-	-	-	-	-	-	-	-	-	-

0	0	0	0	0	0	0	0	0	0			
0	0	0	0	0	0	0	0	0	0	Total		
Blank 32	Blank 33	Blank 34	Blank 35	Blank 36	Blank 37	Blank 38	Blank 39	Blank 40	Blank 41	Adjustments	Control	
-	-	-	-	-	-	-	-	-	-	-	-	-
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-	-	-	-	-	-	-	-	-	-	165	165	-
-	-	-	-	-	-	-	-	-	-	32,227	32,227	-
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-	-	-	-	-	-	-	-	-	-	(3,355)	(3,355)	0
-	-	-	-	-	-	-	-	-	-	(3,355)	(3,355)	0
-	-	-	-	-	-	-	-	-	-	21,952	21,952	0
-	-	-	-	-	-	-	-	-	-	(4,735)	(4,735)	(0)
-	-	-	-	-	-	-	-	-	-	6,667	6,667	-
-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	(5,097)	(5,097)	(0)
-	-	-	-	-	-	-	-	-	-	18,787	18,787	0
-	-	-	-	-	-	-	-	-	-	(18,622)	(18,622)	(0)
-	-	-	-	-	-	-	-	-	-	(164,407)	(164,407)	0
-	-	-	-	-	-	-	-	-	-	(4,924)	(4,924)	(0)
-	-	-	-	-	-	-	-	-	-	14,075	14,075	(0)
-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	(173,557)	(173,557)	0
-	-	-	-	-	-	-	-	-	-	-		
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-	-	-	-	-	-	-	-	-	-	731	731	0
-	-	-	-	-	-	-	-	-	-	(172,826)	(172,826)	0
-	-	-	-	-	-	-	-	-	-	165	165	-
-	-	-	-	-	-	-	-	-	-	23,884	23,884	0
-	-	-	-	-	-	-	-	-	-	(3,565)	(3,565)	0
-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	(14,741)	(14,741)	(0)
-	-	-	-	-	-	-	-	-	-	(1,276)	(1,276)	(0)
-	-	-	-	-	-	-	-	-	-	(4,138)	(4,138)	(0)
-	-	-	-	-	-	-	-	-	-	(314)	(314)	(0)
-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	(314)	(314)	(0)
-	-	-	-	-	-	-	-	-	-	(3,823)	(3,823)	(0)
-	-	-	-	-	-	-	-	-	-	(803)	(803)	(0)
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-	-	-	-	-	-	-	-	-	-	(3,980)	(3,980)	(0)
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-	-	-	-	-	-	-	-	-	-	(5,097)	(5,097)	(0)

Base Rates Needed for Reasonable Return
Production
UE 394
($000)

	Updated Initial	Adjustments	Adjusted Results	Change for Reasonable Return	Results at Reasonable Return
Sales to Consumers	1,114,341	-	1,114,341	33,605	1,147,946
Other Revenues	(3,365)	165	(3,200)		(3,200)
Total Operating Revenues	1,110,976	165	1,111,141	33,605	1,144,746
Net Variable Power Cost	511,766	32,227	543,993		543,993
Fixed Plant Cost	126,068	-	126,068		126,068
Transmission O&M	2,298	-	2,298		2,298
Distribution O&M	247	-	247		247
Total Fixed O&M	128,613	-	128,613	-	128,613
Customer Accounts	108	-	108		108
Uncollectibles per Rev Req Model	-	-	-		-
Customer Service & Sales	14	-	14		14
OPUC Fee	4,540	-	4,540	136	4,676
Admin. & General	48,488	(740)	47,748		47,748
Other O&M	53,149	(740)	52,409	136	52,545
Total Operating & Maintenance	693,528	31,487	725,015	136	725,151
Depreciation & Amortization	165,684	12,158	177,842		177,842
Other Taxes	42,578	2,753	45,331		45,331
Franchise Fee	-		-		-
Income Taxes	37,906	(11,210)	26,696	9,034	35,730
Total Oper. Expenses & Taxes	939,696	35,187	974,883	9,171	984,054
Utility Operating Income	171,281	(35,022)	136,258	24,434	160,693
Average Rate Base					
Avg. Gross Plant	5,038,482	(142,904)	4,895,578		4,895,578
Avg. Accum. Deprec.	2,142,046	12,173	2,154,219		2,154,219
Avg. Accum. Def Tax	450,884	2,069	452,953		452,953
Avg. Accum. Def ITC	-	-	-		-
Avg. Net Utility Plant	2,445,551	(157,145)	2,288,406	0	2,288,406
Operating Materials & Fuel	45,763	-	45,763		45,763
Deferred Programs & Investments	817	-	817		817
Misc. Deferred Credits	(14,478)	-	(14,478)		(14,478)
Working Cash	36,559	1,369	37,928	357	38,285
Average Rate Base	2,514,212	(155,776)	2,358,436	357	2,358,793
Rate of Return	6.81%		5.78%		6.81%
Implied Return on Equity	9.50%		7.43%		9.50%
Income Taxes					
Book Revenues	1,110,976	165	1,111,141	33,605	1,144,746
Book Expenses	901,790	46,398	948,187	136	948,323
Interest @ Weighted Cost of Debt	51,856	(3,213)	48,643	7	48,650
Temporary Sch M Differences	68,750	(2,333)	66,417	-	66,417
Production Deduction	-	-	-	-	-
Permanent M Differences	(6,032)	(1,499)	(7,531)	-	(7,531)
State Taxable Income	94,613	(39,187)	55,426	33,461	88,887
			-		-
State Income Tax	7,185	(2,976)	4,209	2,541	6,750
State Tax Credit	(5)	-	(5)	-	(5)
Net State Income Tax	7,181	(2,976)	4,205	2,541	6,746
			-		-
Federal Taxable Income	87,432	(36,211)	51,221	30,920	82,141
			-		-
Fed Tax @ 21%	18,361	(7,604)	10,756	6,493	17,250
			-		-
Federal Tax Credits	-	-	-	-	-
Deferred Taxes	18,562	(630)	17,932	-	17,932
Excess Deferred Income Tax Reversal (ARAM)	(6,197)	-	(6,197)	-	(6,197)
Total Income Tax	37,906	(11,210)	26,696	9,034	35,730

Base Rates Needed for Reasonable Return
Production
UE 394
($000)

	NVPC	Other Production	Total Production ROO
Sales to Consumers	548,038	599,908	1,147,946
Other Revenues		(3,200)	(3,200)
Total Operating Revenues	548,038	596,709	1,144,746
Net Variable Power Cost	543,993		543,993
Fixed Plant Cost		126,068	126,068
Transmission O&M		2,298	2,298
Distribution O&M		247	247
Total Fixed O&M	-	128,613	128,613
Customer Accounts		108	108
Uncollectibles per Rev Req Model	-	-	-
Customer Service & Sales		14	14
OPUC Fee	2,223	2,454	4,676
Admin. & General		47,748	47,748
Other O&M	2,223	50,323	52,545
Total Operating & Maintenance	546,215	178,935	725,151
Depreciation & Amortization		177,842	177,842
Other Taxes		45,331	45,331
Franchise Fee			
Income Taxes	374	35,357	35,730
Total Oper. Expenses & Taxes	546,589	437,465	984,054
Utility Operating Income	1,449	159,244	160,693
Average Rate Base			
Avg. Gross Plant		4,895,578	4,895,578
Avg. Accum. Deprec.		2,154,219	2,154,219
Avg. Accum. Def Tax		452,953	452,953
Avg. Accum. Def ITC		-	-
Avg. Net Utility Plant	0	2,288,406	2,288,406
Operating Materials & Fuel		45,763	45,763
Deferred Programs & Investments		817	817
Misc. Deferred Credits		(14,478)	(14,478)
Working Cash	21,265	17,020	38,285
Average Rate Base	21,265	2,337,528	2,358,793
Rate of Return	6.81%	6.81%	6.81%
Implied Return on Equity	9.50%	9.50%	9.50%
Income Taxes			
Book Revenues	548,038	596,709	1,144,746
Book Expenses	546,215	402,108	948,323
Interest @ Weighted Cost of Debt	439	48,212	48,650
Temporary Sch M Differences	-	66,417	66,417
Production Deduction	-	-	-
Permanent M Differences	-	(7,531)	(7,531)
State Taxable Income	1,384	87,504	88,887
State Income Tax	105	6,645	6,750
State Tax Credit	-	(5)	(5)
Net State Income Tax	105	6,641	6,746
Federal Taxable Income	1,279	80,863	82,141
Fed Tax @ 21%	269	16,981	17,250
Federal Tax Credits		-	-
Deferred Taxes	-	17,932	17,932
Excess Deferred Income Tax Reversal (ARAM)	-	(6,197)	(6,197)
Total Income Tax	374	35,357	35,730

Base Rates Needed for Reasonable Return
Transmission
UE 394
($000)

	Updated Initial	Adjustments	Adjusted Results	Change for Reasonable Return	Results at Reasonable Return
Sales to Consumers	86,476	-	86,476	(810)	85,667
Other Revenues	18,644	-	18,644		18,644
Total Operating Revenues	105,120	-	105,120	(810)	104,311
Net Variable Power Cost	-	-	-		-
Fixed Plant Cost	-	-	-		-
Transmission O&M	17,576	-	17,576		17,576
Distribution O&M	-	-	-		-
Total Fixed O&M	17,576	-	17,576	-	17,576
Customer Accounts	-	-	-		-
Uncollectibles per Rev Req Model	-	-	-		-
Customer Service & Sales	-	-	-		-
OPUC Fee	351	-	351	(3)	347
Admin. & General	7,277	(135)	7,142		7,142
Other O&M	7,627	(135)	7,493	(3)	7,489
Total Operating & Maintenance	25,204	(135)	25,069	(3)	25,066
Depreciation & Amortization	23,366	(830)	22,536		22,536
Other Taxes	8,834	346	9,180		9,180
Franchise Fee	-		-		-
Income Taxes	9,222	189	9,411	(218)	9,194
Total Oper. Expenses & Taxes	66,626	(430)	66,196	(221)	65,975
Utility Operating Income	38,494	430	38,924	(589)	38,335
Average Rate Base					
Avg. Gross Plant	994,664	(2,117)	992,547		992,547
Avg. Accum. Deprec.	374,801	(1,119)	373,682		373,682
Avg. Accum. Def Tax	61,764	1,313	63,077		63,077
Avg. Accum. Def ITC	-	-	-		-
Avg. Net Utility Plant	558,099	(2,310)	555,789	0	555,789
Operating Materials & Fuel	1,452	-	1,452		1,452
Deferred Programs & Investments	5,477	-	5,477		5,477
Misc. Deferred Credits	(2,568)	-	(2,568)		(2,568)
Working Cash	2,592	(17)	2,575	(9)	2,567
Average Rate Base	565,052	(2,327)	562,725	(9)	562,717
Rate of Return	6.81%		6.92%		6.81%
Implied Return on Equity	9.50%		9.71%		9.50%
Income Taxes					
Book Revenues	105,120	-	105,120	(810)	104,311
Book Expenses	57,404	(618)	56,785	(3)	56,782
Interest @ Weighted Cost of Debt	11,654	(48)	11,606	(0)	11,606
Temporary Sch M Differences	8,847	(1,130)	7,717	-	7,717
Production Deduction	-	-	-	-	-
Permanent M Differences	(734)	(33)	(767)	-	(767)
State Taxable Income	27,949	1,829	29,778	(806)	28,972
			-		-
State Income Tax	2,123	139	2,261	(61)	2,200
State Tax Credit	(1)	-	(1)	-	(1)
Net State Income Tax	2,122	139	2,260	(61)	2,199
			-		-
Federal Taxable Income	25,827	1,690	27,517	(745)	26,772
			-		-
Fed Tax @ 21%	5,424	355	5,779	(156)	5,622
			-		-
Federal Tax Credits	-	-	-	-	-
Deferred Taxes	2,389	(305)	2,084	-	2,084
Excess Deferred Income Tax Reversal (ARAM)	(712)	-	(712)	-	(712)
Total Income Tax	9,222	189	9,411	(218)	9,194

Base Rates Needed for Reasonable Return
Distribution
UE 394
($000)

	Updated Initial	Adjustments	Adjusted Results	Change for Reasonable Return	Results at Reasonable Return
Sales to Consumers	720,019	-	720,019	(21,821)	698,199
Other Revenues	19,185	-	19,185		19,185
Total Operating Revenues	739,204	-	739,204	(21,821)	717,384
Net Variable Power Cost	-	-	-		-
Fixed Plant Cost	-	-	-		-
Transmission O&M	-	-	-		-
Distribution O&M	152,522	(6,920)	145,602		145,602
Total Fixed O&M	152,522	(6,920)	145,602	-	145,602
Customer Accounts	-	-	-		-
Uncollectibles per Rev Req Model	6,844	-	6,844	32	6,876
Customer Service & Sales	-	-	-		-
OPUC Fee	2,920	-	2,920	(88)	2,831
Admin. & General	84,234	(1,685)	82,549		82,549
Other O&M	93,998	(1,685)	92,313	(57)	92,256
Total Operating & Maintenance	246,520	(8,605)	237,915	(57)	237,858
Depreciation & Amortization	184,878	(15,054)	169,824		169,824
Other Taxes	44,994	2,883	47,876		47,876
Franchise Fee	53,598	-	53,598	248	53,846
Income Taxes	42,707	5,617	48,324	(5,942)	42,382
Total Oper. Expenses & Taxes	572,696	(15,160)	557,536	(5,750)	551,785
Utility Operating Income	166,508	15,160	181,668	(16,070)	165,598
Average Rate Base					
Avg. Gross Plant	5,170,569	(18,797)	5,151,772		5,151,772
Avg. Accum. Deprec.	2,569,840	(15,084)	2,554,756		2,554,756
Avg. Accum. Def Tax	155,078	8,828	163,906		163,906
Avg. Accum. Def ITC	-	-	-		-
Avg. Net Utility Plant	2,445,651	(12,541)	2,433,110	0	2,433,110
Operating Materials & Fuel	20,509	-	20,509		20,509
Deferred Programs & Investments	-	-	-		-
Misc. Deferred Credits	(44,287)	-	(44,287)		(44,287)
Working Cash	22,281	(590)	21,691	(224)	21,467
Average Rate Base	2,444,154	(13,131)	2,431,023	(224)	2,430,799
Rate of Return	6.81%		7.47%		6.81%
Implied Return on Equity	9.50%		10.82%		9.50%
Income Taxes					
Book Revenues	739,204	-	739,204	(21,821)	717,384
Book Expenses	529,989	(20,777)	509,212	192	509,404
Interest @ Weighted Cost of Debt	50,411	(271)	50,140	(5)	50,135
Temporary Sch M Differences	70,811	(10,517)	60,293	-	60,293
Production Deduction	-	-	-	-	-
Permanent M Differences	(6,790)	245	(6,545)	-	(6,545)
State Taxable Income	94,784	31,320	126,104	(22,008)	104,097
			-		-
State Income Tax	7,198	2,379	9,577	(1,671)	7,905
State Tax Credit	(4)	-	(4)	-	(4)
Net State Income Tax	7,194	2,379	9,573	(1,671)	7,901
			-		-
Federal Taxable Income	87,590	28,942	116,531	(20,336)	96,195
			-		-
Fed Tax @ 21%	18,394	6,078	24,472	(4,271)	20,201
			-		-
Federal Tax Credits	-	-	-	-	-
Deferred Taxes	19,119	(2,840)	16,279	-	16,279
Excess Deferred Income Tax Reversal (ARAM)	(1,999)	-	(1,999)	-	(1,999)
Total Income Tax	42,707	5,617	48,324	(5,942)	42,382

Base Rates Needed for Reasonable Return
Ancillary Services
UE 394
($000)

	Updated Initial	Adjustments	Adjusted Results	Change for Reasonable Return	Results at Reasonable Return
Sales to Consumers	5,119	-	5,119	-	5,119
Other Revenues	(5,119)	-	(5,119)		(5,119)
Total Operating Revenues	-	-	-	-	-
Net Variable Power Cost	-	-	-		-
Fixed Plant Cost	-	-	-		-
Transmission O&M	-	-	-		-
Distribution O&M	-	-	-		-
Total Fixed O&M	-	-	-	-	-
Customer Accounts	-	-	-		-
Uncollectibles per Rev Req Model	-	-	-	-	-
Customer Service & Sales	-	-	-		-
OPUC Fee	-		-		-
Admin. & General	-	-	-		-
Other O&M	-	-	-	-	-
Total Operating & Maintenance	-	-	-	-	-
Depreciation & Amortization	-	-	-		-
Other Taxes	-	-	-		-
Franchise Fee	-		-		-
Income Taxes	-	-	-	-	-
Total Oper. Expenses & Taxes	-	-	-	-	-
Utility Operating Income	-	-	-	-	-
Average Rate Base					
Avg. Gross Plant	-	-	-		-
Avg. Accum. Deprec.	-	-	-		-
Avg. Accum. Def Tax	-	-	-		-
Avg. Accum. Def ITC	-	-	-		-
Avg. Net Utility Plant	0	0	0	0	0
Operating Materials & Fuel	-	-	-		-
Deferred Programs & Investments	-	-	-		-
Misc. Deferred Credits	-	-	-		-
Working Cash	-	-	-	-	-
Average Rate Base	-	-	-	-	-
Rate of Return					
Implied Return on Equity					
Income Taxes					
Book Revenues	-	-	-	-	-
Book Expenses	-	-	-	-	-
Interest @ Weighted Cost of Debt	-	-	-	-	-
Temporary Sch M Differences	-	-	-	-	-
Production Deduction	-	-	-	-	-
Permanent M Differences	-	-	-	-	-
State Taxable Income	-	-	-	-	-
			-		-
State Income Tax	-	-	-	-	-
State Tax Credit	-	-	-	-	-
Net State Income Tax	-	-	-	-	-
			-		-
Federal Taxable Income	-	-	-	-	-
			-		-
Fed Tax @ 21%	-	-	-	-	-
			-		-
Federal Tax Credits	-	-	-	-	-
Deferred Taxes	-	-	-	-	-
Excess Deferred Income Tax Reversal (ARAM)	-	-	-	-	-
Total Income Tax	-	-	-	-	-

Base Rates Needed for Reasonable Return
Metering
UE 394
($000)

	Updated Initial	Adjustments	Adjusted Results	Change for Reasonable Return	Results at Reasonable Return
Sales to Consumers	6,194	-	6,194	(50)	6,144
Other Revenues	-	-	-		-
Total Operating Revenues	6,194	-	6,194	(50)	6,144
Net Variable Power Cost	-	-	-		-
Fixed Plant Cost	-	-	-		-
Transmission O&M	-	-	-		-
Distribution O&M	-	-	-		-
Total Fixed O&M	-	-	-	-	-
Customer Accounts	2,036	-	2,036		2,036
Uncollectibles per Rev Req Model	-	-	-		-
Customer Service & Sales	-	-	-		-
OPUC Fee	25	-	25	(0)	25
Admin. & General	1,457	(30)	1,427		1,427
Other O&M	3,518	(30)	3,488	(0)	3,488
Total Operating & Maintenance	3,518	(30)	3,488	(0)	3,488
Depreciation & Amortization	924	(38)	886		886
Other Taxes	394	25	419		419
Franchise Fee	-		-		-
Income Taxes	251	12	263	(13)	249
Total Oper. Expenses & Taxes	5,087	(31)	5,056	(14)	5,042
Utility Operating Income	1,107	31	1,138	(36)	1,102
Average Rate Base					
Avg. Gross Plant	59,886	(16)	59,870		59,870
Avg. Accum. Deprec.	40,918	(33)	40,885		40,885
Avg. Accum. Def Tax	2,341	97	2,438		2,438
Avg. Accum. Def ITC	-	-	-		-
Avg. Net Utility Plant	16,627	(80)	16,547	0	16,547
Operating Materials & Fuel	-	-	-		-
Deferred Programs & Investments	-	-	-		-
Misc. Deferred Credits	(571)	-	(571)		(571)
Working Cash	198	(1)	197	(1)	196
Average Rate Base	16,254	(81)	16,173	(1)	16,172
Rate of Return	6.81%		7.04%		6.81%
Implied Return on Equity	9.50%		9.95%		9.50%
Income Taxes					
Book Revenues	6,194	-	6,194	(50)	6,144
Book Expenses	4,836	(43)	4,793	(0)	4,793
Interest @ Weighted Cost of Debt	335	(2)	334	(0)	334
Temporary Sch M Differences	259	(28)	231	-	231
Production Deduction	-	-	-	-	-
Permanent M Differences	(20)	0	(19)	-	(19)
State Taxable Income	784	73	856	(50)	806
			-		-
State Income Tax	60	6	65	(4)	61
State Tax Credit	(0)	-	(0)	-	(0)
Net State Income Tax	59	6	65	(4)	61
			-		-
Federal Taxable Income	724	67	791	(46)	745
			-		-
Fed Tax @ 21%	152	14	166	(10)	156
			-		-
Federal Tax Credits	-	-	-		-
Deferred Taxes	70	(8)	62	-	62
Excess Deferred Income Tax Reversal (ARAM)	(31)	-	(31)	-	(31)
Total Income Tax	251	12	263	(13)	249

Base Rates Needed for Reasonable Return
Billing
UE 394
($000)

	Updated Initial	Adjustments	Adjusted Results	Change for Reasonable Return	Results at Reasonable Return
Sales to Consumers	37,715	-	37,715	(114)	37,602
Other Revenues	-	-	-		-
Total Operating Revenues	37,715	-	37,715	(114)	37,602
Net Variable Power Cost	-	-	-		-
Fixed Plant Cost	-	-	-		-
Transmission O&M	-	-	-		-
Distribution O&M	-	-	-		-
Total Fixed O&M	-	-	-	-	-
Customer Accounts	21,334	-	21,334		21,334
Uncollectibles per Rev Req Model	-	-	-		-
Customer Service & Sales	1,567	-	1,567		1,567
OPUC Fee	153	-	153	(0)	152
Admin. & General	5,266	(108)	5,157		5,157
Other O&M	28,320	(108)	28,212	(0)	28,211
Total Operating & Maintenance	28,320	(108)	28,212	(0)	28,211
Depreciation & Amortization	3,345	(137)	3,208		3,208
Other Taxes	1,310	151	1,461		1,461
Franchise Fee	-		-		-
Income Taxes	938	26	964	(31)	933
Total Oper. Expenses & Taxes	33,913	(68)	33,845	(31)	33,814
Utility Operating Income	3,803	68	3,870	(83)	3,788
Average Rate Base					
Avg. Gross Plant	96,432	(58)	96,374		96,374
Avg. Accum. Deprec.	36,688	(121)	36,567		36,567
Avg. Accum. Def Tax	3,548	277	3,825		3,825
Avg. Accum. Def ITC	-	-	-		-
Avg. Net Utility Plant	56,196	(214)	55,983	0	55,983
Operating Materials & Fuel	-	-	-		-
Deferred Programs & Investments	-	-	-		-
Misc. Deferred Credits	(1,698)	-	(1,698)		(1,698)
Working Cash	1,319	(3)	1,317	(1)	1,316
Average Rate Base	55,817	(216)	55,601	(1)	55,600
Rate of Return	6.81%		6.96%		6.81%
Implied Return on Equity	9.50%		9.80%		9.50%
Income Taxes					
Book Revenues	37,715	-	37,715	(114)	37,602
Book Expenses	32,975	(94)	32,881	(0)	32,881
Interest @ Weighted Cost of Debt	1,151	(4)	1,147	(0)	1,147
Temporary Sch M Differences	904	(103)	801	-	801
Production Deduction	-	-	-	-	-
Permanent M Differences	(77)	2	(76)	-	(76)
State Taxable Income	2,763	200	2,962	(113)	2,849
			-		-
State Income Tax	210	15	225	(9)	216
State Tax Credit	(0)	-	(0)	-	(0)
Net State Income Tax	210	15	225	(9)	216
			-		-
Federal Taxable Income	2,553	185	2,738	(105)	2,633
			-		-
Fed Tax @ 21%	536	39	575	(22)	553
			-		-
Federal Tax Credits	-	-	-	-	-
Deferred Taxes	244	(28)	216	-	216
Excess Deferred Income Tax Reversal (ARAM)	(52)	-	(52)	-	(52)
Total Income Tax	938	26	964	(31)	933

Base Rates Needed for Reasonable Return
Other Consumer
UE 394
($000)

	Updated Initial	Adjustments	Adjusted Results	Change for Reasonable Return	Results at Reasonable Return
Sales to Consumers	127,220	-	127,220	(1,095)	126,125
Other Revenues	-	-	-		-
Total Operating Revenues	127,220	-	127,220	(1,095)	126,125
Net Variable Power Cost	-	-	-		-
Fixed Plant Cost	-	-	-		-
Transmission O&M	-	-	-		-
Distribution O&M	-	-	-		-
Total Fixed O&M	-	-	-	-	-
Customer Accounts	36,876	-	36,876		36,876
Uncollectibles per Rev Req Model	-	-	-		-
Customer Service & Sales	21,151	-	21,151		21,151
OPUC Fee	516	-	516	(4)	511
Admin. & General	31,602	(657)	30,945		30,945
Other O&M	90,144	(657)	89,488	(4)	89,483
Total Operating & Maintenance	90,144	(657)	89,488	(4)	89,483
Depreciation & Amortization	20,258	(827)	19,431		19,431
Other Taxes	5,141	509	5,651		5,651
Franchise Fee	-		-		-
Income Taxes	2,389	268	2,657	(294)	2,363
Total Oper. Expenses & Taxes	117,933	(707)	117,226	(299)	116,927
Utility Operating Income	9,287	707	9,994	(796)	9,198
Average Rate Base					
Avg. Gross Plant	270,107	(516)	269,591		269,591
Avg. Accum. Deprec.	119,751	(733)	119,017		119,017
Avg. Accum. Def Tax	8,339	1,488	9,827		9,827
Avg. Accum. Def ITC	-	-	-		-
Avg. Net Utility Plant	142,018	(1,271)	140,747	0	140,747
Operating Materials & Fuel	-	-	-		-
Deferred Programs & Investments	-	-	-		-
Misc. Deferred Credits	(10,285)	-	(10,285)		(10,285)
Working Cash	4,588	(28)	4,561	(12)	4,549
Average Rate Base	136,321	(1,298)	135,023	(12)	135,011
Rate of Return	6.81%		7.40%		6.81%
Implied Return on Equity	9.50%		10.68%		9.50%
Income Taxes					
Book Revenues	127,220	-	127,220	(1,095)	126,125
Book Expenses	115,544	(975)	114,569	(4)	114,564
Interest @ Weighted Cost of Debt	2,812	(27)	2,785	(0)	2,785
Temporary Sch M Differences	4,646	(624)	4,022	-	4,022
Production Deduction	-	-	-	-	-
Permanent M Differences	(596)	10	(586)	-	(586)
State Taxable Income	4,814	1,616	6,430	(1,090)	5,340
			-		-
State Income Tax	366	123	488	(83)	406
State Tax Credit	(0)	-	(0)	-	(0)
Net State Income Tax	365	123	488	(83)	405
			-		-
Federal Taxable Income	4,449	1,493	5,942	(1,007)	4,935
			-		-
Fed Tax @ 21%	934	314	1,248	(212)	1,036
			-		-
Federal Tax Credits	-	-	-	-	-
Deferred Taxes	1,254	(168)	1,086	-	1,086
Excess Deferred Income Tax Reversal (ARAM)	(165)	-	(165)	-	(165)
Total Income Tax	2,389	268	2,657	(294)	2,363

Base Rates Needed for Reasonable Return
Retail / Non-Utility
UE 394
($000)

	Updated Initial	Adjustments	Adjusted Results	Change for Reasonable Return	Results at Reasonable Return
Sales to Consumers	240	-	240	(7)	233
Other Revenues	-	-	-		-
Total Operating Revenues	240	-	240	(7)	233
Net Variable Power Cost	-	-	-		-
Fixed Plant Cost	-	-	-		-
Transmission O&M	-	-	-		-
Distribution O&M	-	-	-		-
Total Fixed O&M	-	-	-	-	-
Customer Accounts	-	-	-		-
Uncollectibles per Rev Req Model	-	-	-		-
Customer Service & Sales	-	-	-		-
OPUC Fee	-	-	-		-
Admin. & General	1	-	1		1
Other O&M	1	-	1	-	1
Total Operating & Maintenance	1	-	1	-	1
Depreciation & Amortization	167	(7)	160		160
Other Taxes	11	-	11		11
Franchise Fee	-		-		-
Income Taxes	12	2	14	(2)	12
Total Oper. Expenses & Taxes	191	(5)	186	(2)	184
Utility Operating Income	49	5	54	(5)	49
Average Rate Base					
Avg. Gross Plant	1,623	-	1,623		1,623
Avg. Accum. Deprec.	825	(6)	819		819
Avg. Accum. Def Tax	90	2	92		92
Avg. Accum. Def ITC	-	-	-		-
Avg. Net Utility Plant	708	4	712	0	712
Operating Materials & Fuel	-	-	-		-
Deferred Programs & Investments	-	-	-		-
Misc. Deferred Credits	-	-	-		-
Working Cash	7	(0)	7	(0)	7
Average Rate Base	716	3	719	(0)	719
Rate of Return	6.81%		7.47%		6.81%
Implied Return on Equity	9.50%		10.82%		9.50%
Income Taxes					
Book Revenues	240	-	240	(7)	233
Book Expenses	178	(7)	172	-	172
Interest @ Weighted Cost of Debt	15	0	15	(0)	15
Temporary Sch M Differences	26	-	26	-	26
Production Deduction	-	-	-	-	-
Permanent M Differences	(3)	-	(3)	-	(3)
State Taxable Income	23	7	30	(7)	24
			-		-
State Income Tax	2	1	2	(0)	2
State Tax Credit	(0)	-	(0)	-	(0)
Net State Income Tax	2	1	2	(0)	2
			-		-
Federal Taxable Income	22	6	28	(6)	22
			-		-
Fed Tax @ 21%	5	1	6	(1)	5
			-		-
Federal Tax Credits	-				
Deferred Taxes	7	-	7	-	7
Excess Deferred Income Tax Reversal (ARAM)	(1)	-	(1)	-	(1)
Total Income Tax	12	2	14	(2)	12

Base Rates Needed for Reasonable Return
Control ROO Total
UE 394
($000)

	Updated Initial	Adjustments	Adjusted Results	Change for Reasonable Return	Results at Reasonable Return
Sales to Consumers	2,097,324	-	2,097,324	9,710	2,107,034
Other Revenues	29,346	165	29,511	-	29,511
Total Operating Revenues	2,126,670	165	2,126,835	9,710	2,136,544
Net Variable Power Cost	511,766	32,227	543,993	-	543,993
Fixed Plant Cost	126,068	-	126,068	-	126,068
Transmission O&M	19,874	-	19,874	-	19,874
Distribution O&M	152,769	(6,920)	145,849	-	145,849
Total Fixed O&M	298,711	(6,920)	291,791	-	291,791
Customer Accounts	60,354	-	60,354	-	60,354
Uncollectibles per Rev Req Model	6,844	-	6,844	32	6,876
Customer Service & Sales	22,731	-	22,731	-	22,731
OPUC Fee	8,505	-	8,505	39	8,544
Admin. & General	178,324	(3,355)	174,969	-	174,969
Other O&M	276,758	(3,355)	273,403	71	273,474
Total Operating & Maintenance	1,087,235	21,952	1,109,187	71	1,109,258
Depreciation & Amortization	398,621	(4,735)	393,886	-	393,886
Other Taxes	103,262	6,667	109,929	-	109,929
Franchise Fee	53,598	-	53,598	248	53,846
Income Taxes	93,426	(5,097)	88,329	2,535	90,864
Total Oper. Expenses & Taxes	1,736,142	18,787	1,754,928	2,854	1,757,782
Utility Operating Income	390,528	(18,622)	371,907	6,855	378,762
Average Rate Base					
Avg. Gross Plant	11,631,763	(164,407)	11,467,356	-	11,467,356
Avg. Accum. Deprec.	5,284,869	(4,924)	5,279,945	-	5,279,945
Avg. Accum. Def Tax	682,043	14,075	696,118	-	696,118
Avg. Accum. Def ITC	-	-	-	-	-
Avg. Net Utility Plant	5,664,850	(173,557)	5,491,293	0	5,491,293
Operating Materials & Fuel	67,724	-	67,724	-	67,724
Deferred Programs & Investments	6,294	-	6,294	-	6,294
Misc. Deferred Credits	(73,886)	-	(73,886)	-	(73,886)
Working Cash	67,545	731	68,275	111	68,387
Average Rate Base	5,732,527	(172,826)	5,559,700	111	5,559,811
Rate of Return	6.81%		6.69%		6.81%
Implied Return on Equity	9.50%		9.25%		9.50%
Income Taxes					
Book Revenues	2,126,670	165	2,126,835	9,710	2,136,544
Book Expenses	1,642,715	23,884	1,666,599	319	1,666,919
Interest @ Weighted Cost of Debt	118,233	(3,565)	114,669	2	114,671
Temporary Sch M Differences	154,243	(14,736)	139,508	-	139,508
Production Deduction	-	-	-	-	-
Permanent M Differences	(14,252)	(1,276)	(15,527)	-	(15,527)
State Taxable Income	225,729	(4,143)	221,587	9,388	230,975
			-		-
State Income Tax	17,143	(315)	16,828	713	17,541
State Tax Credit	(10)	-	(10)	-	(10)
Net State Income Tax	17,133	(315)	16,818	713	17,531
			-		-
Federal Taxable Income	208,597	(3,828)	204,769	8,675	213,444
			-		-
Fed Tax @ 21%	43,805	(804)	43,001	1,822	44,823
			-		-
Federal Tax Credits	-	-	-	-	-
Deferred Taxes	41,645	(3,979)	37,666	-	37,666
Excess Deferred Income Tax Reversal (ARAM)	(9,157)	-	(9,157)	-	(9,157)
Total Income Tax	93,426	(5,097)	88,329	2,535	90,864

Base Rates Needed for Reasonable Return
Regulated ROO Total
UE 394
($000)

	Updated Initial	Adjustments	Adjusted Results	Change for Reasonable Return	Results at Reasonable Return	Check
Sales to Consumers	2,097,085	-	2,097,085	9,716	2,106,801	
Other Revenues	29,346	165	29,511	-	29,511	
Total Operating Revenues	2,126,430	165	2,126,595	9,716	2,136,311	
Net Variable Power Cost	511,766	32,227	543,993	-	543,993	
Fixed Plant Cost	126,068	-	126,068	-	126,068	
Transmission O&M	19,874	-	19,874	-	19,874	
Distribution O&M	152,769	(6,920)	145,849	-	145,849	
Total Fixed O&M	298,711	(6,920)	291,791	-	291,791	
Customer Accounts	60,354	-	60,354	-	60,354	
Uncollectibles per Rev Req Model	6,844	-	6,844	32	6,876	0.3264%
Customer Service & Sales	22,731	-	22,731	-	22,731	
OPUC Fee	8,505	-	8,505	39	8,544	0.4055%
Admin. & General	178,323	(3,355)	174,968	-	174,968	
Other O&M	276,757	(3,355)	273,402	71	273,473	
Total Operating & Maintenance	1,087,234	21,952	1,109,186	71	1,109,257	
Depreciation & Amortization	398,454	(4,728)	393,726	-	393,726	
Other Taxes	103,251	6,667	109,918	-	109,918	
Franchise Fee	53,598	-	53,598	248	53,846	2.5558%
Income Taxes	93,414	(5,099)	88,315	2,536	90,851	
Total Oper. Expenses & Taxes	1,735,951	18,792	1,754,742	2,856	1,757,598	
Utility Operating Income	390,480	(18,627)	371,853	6,860	378,713	378,713
Average Rate Base						
Avg. Gross Plant	11,630,140	(164,407)	11,465,733	-	11,465,733	
Avg. Accum. Deprec.	5,284,044	(4,918)	5,279,126	-	5,279,126	
Avg. Accum. Def Tax	681,954	14,072	696,026	-	696,026	
Avg. Accum. Def ITC	-	-	-	-	-	
Avg. Net Utility Plant	5,664,142	(173,561)	5,490,581	0	5,490,581	
Operating Materials & Fuel	67,724	-	67,724	-	67,724	
Deferred Programs & Investments	6,294	-	6,294	-	6,294	
Misc. Deferred Credits	(73,886)	-	(73,886)	-	(73,886)	
Working Cash	67,537	731	68,268	111	68,379	3.8905%
Average Rate Base	5,731,811	(172,830)	5,558,981	111	5,559,092	
Rate of Return	6.813%		6.689%		6.813%	
Implied Return on Equity	9.50%		9.25%		9.50%	9.50%
Income Taxes						
Book Revenues	2,126,430	165	2,126,595	9,716	2,136,311	
Book Expenses	1,642,537	23,891	1,666,428	319	1,666,747	
Interest @ Weighted Cost of Debt	118,219	(3,565)	114,654	2	114,656	
Temporary Sch M Differences	154,217	(14,736)	139,481	-	139,481	
Production Deduction	-	-	-	-	-	
Permanent M Differences	(14,248)	(1,276)	(15,524)	-	(15,524)	
State Taxable Income	225,706	(4,149)	221,557	9,394	230,951	
			-		-	
State Income Tax	17,141	(315)	16,826	713	17,539	
State Tax Credit	(10)	-	(10)	-	(10)	
Net State Income Tax	17,131	(315)	16,816	713	17,529	
			-		-	
Federal Taxable Income	208,575	(3,834)	204,741	8,681	213,422	
			-		-	
Fed Tax @ 21%	43,801	(805)	42,996	1,823	44,819	
			-		-	
Federal Tax Credits	-	-	-	-	-	
Deferred Taxes	41,638	(3,979)	37,659	-	37,659	
Excess Deferred Income Tax Reversal (ARAM)	(9,156)	-	(9,156)	-	(9,156)	
Total Income Tax	93,414	(5,099)	88,315	2,536	90,851	

Unbundled Revenue Requirement
Dollars in $000s

Generation	1,147,946
Transmission	85,667
Distribution	698,199
Ancillary	5,119
Metering	6,144
Billing	37,602
Other Consumer	126,125
Total Regulated	2,106,801

ROE = 9.50%
11-15-21 NVPC Update
First and Second Partial Stipulations
Settlement Proposal for Third Partial Stipulation

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 394

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for 2022 General Rate Revision	**PARTIAL STIPULATION**

This Fourth Partial Stipulation ("Stipulation") is between Portland General Electric Company ("PGE"), Staff of the Public Utility Commission of Oregon ("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"), Calpine Solutions, and Small Business Utility Advocates ("SBUA"), (collectively, the "Stipulating Parties"). The Stipulating Parties are all of the parties in this proceeding.

PGE previously filed a First Partial Stipulation in this docket resolving all issues related to Cost of Capital in this general rate case. PGE then filed a Second Partial Stipulation on November 5, 2021, and a Third Partial Stipulation on January 18, 2022, after reaching agreements with the parties on certain matters through the course of multiple settlement conferences. SBUA was not a party to the First or Second Partial Stipulations. Calpine Solutions did not take a position on the issues resolved in the first three stipulations but did not oppose them. The parties engaged in a fourth round of settlement discussions on February 1, 2022. The Stipulating Parties all participated in these settlement discussions. As a result of the discussions, the Stipulating Parties have reached a compromise settlement resolving several additional issues in this docket, as set forth below.

TERMS OF FOURTH PARTIAL STIPULATION

1. This Stipulation resolves only the general rate case issues described below.
2. Fee Free Bank Card
   a. Stipulating Parties agree that PGE's non-residential customers may only pay up to $1,500 per billing cycle using a credit card or other type of card.
   b. Stipulating Parties agree that PGE may continue to offer the Fee Free Bank Card program after the COVID-19 state of emergency ends.
   c. This Stipulation resolves all issues raised by any party related to the Fee Free Bank Card program in this proceeding.
3. Trojan Nuclear Decommissioning Trust (NDT)
   a. Stipulating Parties agree that PGE will return the 2018 claim year DOE reimbursement of $2,960,544 received in December 2019 to customers via Schedule 143 over a one-year period beginning May 9, 2022. Stipulating Parties agree that PGE will fund this return using the 2020 claim year DOE reimbursement received in December 2021. PGE will contribute the remainder of the 2020 claim year DOE reimbursement to the Trojan NDT.
   b. Stipulating Parties agree that PGE will also refund the $352,098 residual balance of the Schedule 143 balancing account to customers via Schedule 143 over a one-year period beginning May 9, 2022.

c. This Stipulation resolves all issues raised by any party related to the Trojan NDT in this proceeding.

4. Rate Spread and Customer Impact Offset

a. Stipulating Parties agree to settle all rate spread issues based on the following:

i. Using the marginal cost studies filed in this case with updates to loads, forecasted natural gas prices, and cost of capital in the generation marginal cost study.

ii. Applying a customer impact offset to move $2.842 million from Schedule 83, $3.654 million from Schedules 85/485, $2.061 million from Schedules 89/489, and $1.2 million from Schedule 90 and apply $6.585 million to Schedule 7 and $3.177 million to Schedule 32.

iii. CUB is a signatory to every part of this stipulation besides rate spread. CUB does not oppose the rate spread that has been agreed to in this stipulation but does not support it. CUB will provide rationale detailing its non-opposition in its prehearing brief.

iv. Tables reflecting the agreed to rate spread is provided as an exhibit.

5. Schedule 7 Residential Basic Charge

a. Stipulating Parties agree to bifurcate the Schedule 7 Basic Charge into Single- and Multi-Family with the Single Family Basic Charge at $11 and the Multi-Family Basic Charge at $8.

6. Schedule 7 Residential Line Extension Allowance

a. Stipulating Parties agree that the Schedule 7 Line Extension Allowance will not change in this case.

7. Temporary Service

a. Stipulating Parties agree to the changes to temporary service proposed by PGE[1].

8. Generation Demand Charges for Schedules 83 and 85

a. Stipulating Parties agree to create generation demand charges for Schedule 83 and 85, assigning 25% of generation to the new demand charge for each schedule. Starting with direct access opt outs beginning in 2023, transition adjustments for Schedules 483 and 485 will be calculated as the difference between generation cost-of-service *volumetric* charges and market value (as is done now in the absence of a generation demand charge) while the generation demand charge will be applied directly to Schedule 483 and 485 customers during the transition adjustment period. For long-term opt outs, updates to fixed generation costs that are charged volumetrically, such as Schedule 122 RAC updates, will apply to the transition adjustment. Changes to fixed generation costs charged via the generation demand charge will apply directly to the demand charge. Future increases in the generation demand charge that are simply the result of rate redesign (i.e., moving recovery of fixed generation costs from the volumetric charge to the demand charge) will be accompanied by a recalculation of the transition adjustment using the reduced volumetric charge. PGE will address the timeline for ramping in generation demand charges in its next general rate case filing.

9. Habitat Restoration, A-26

a. Stipulating Parties agree that CUB may propose changes to Habitat Restoration options in Docket UM 1020 and that the issue will not be addressed in this case.

[1] UE 394 / PGE / 1200, Macfarlane – Tang / 47 - 48

While CUB and PGE may or may not agree on the proposal, PGE will support consideration of CUB's proposal in Docket UM 1020. CUB and PGE agree to work together in good faith on this matter.

10. Nonbypassability

a. Stipulating Parties agree to make Schedule 137 nonbypassable as proposed by PGE.

b. Stipulating Parties agree that PGE will remove its Schedule 135 demand response nonbypassability proposal from this case. PGE may continue to pursue the nonbypassablity of Schedule 135 in another proceeding.

11. Schedule 138 Energy Storage Cost Recovery

a. Stipulating Parties agree that PGE will include the following language suggested by CUB in Schedule 138: "expenses associated with HB 2193 energy storage pilots." Stipulating Parties also agree that this agreement does not preclude PGE from proposing changes to energy storage related cost recovery under schedules other than Schedule 138 in the future.

12. Remaining Issues

The Stipulating Parties agree that the following items are not resolved by this stipulation and will continue to be litigated in this proceeding:

a. Level III Outage Mechanism

b. Faraday Repowering Cost Recovery Treatment

c. Wildfire Mitigation and Vegetation Management Mechanism

d. Major Deferrals

e. Non-bypassability of Schedule 150

f. Schedule 90 sub-transmission rate

13. Stipulating Parties recommend and request that the Commission approve the adjustments and provisions described herein as appropriate and reasonable resolutions of all issues addressed in this Stipulation.

14. Stipulating Parties agree that this Stipulation is in the public interest, and will result in rates that are fair, just, and reasonable, consistent with the standard in ORS 756.040.

15. Stipulating Parties agree that this Stipulation represents a compromise in the positions of the Stipulating Parties. Without the written consent of all the Stipulating Parties, evidence of conduct or statements, including but not limited to term sheets or other documents created solely for use in settlement conferences in this docket, are confidential and not admissible in this instance or any subsequent proceeding, unless independently discoverable or offered for other purposes allowed under ORS 40.190.

16. Stipulating Parties have negotiated this Stipulation as an integrated document. The Stipulating Parties seek to obtain Commission approval of this Stipulation after initial briefs were filed but prior to evidentiary hearings. If the Commission rejects all or any material part of this Stipulation, or adds any material condition to any final order that is not consistent with this Stipulation, each Stipulating Party reserves its right: (i) pursuant to OAR 860-001-0350(9), to present evidence and argument on the record in support of the Stipulation, including the right to cross-examine witnesses, introduce evidence as deemed appropriate to respond fully to issues presented, and raise issues that are incorporated in the settlements embodied in this Stipulation; and (ii) pursuant to ORS 756.561 and OAR 860-001-0720, to seek rehearing or reconsideration, or pursuant to ORS 756.610 to appeal the Commission's final order. Stipulating Parties agree that in the event the Commission rejects all or any material part of this Stipulation or adds any material condition to any final

order that is not consistent with this Stipulation, Stipulating Parties will meet in good faith within ten days and discuss next steps. A Stipulating Party may withdraw from the Stipulation after this meeting by providing written notice to the Commission and other Stipulating Parties.

17. This Stipulation will be offered into the record in this proceeding as evidence pursuant to OAR 860-001-0350(7). Stipulating Parties agree to support this Stipulation throughout this proceeding and in any appeal and provide witnesses to support this Stipulation (if required by the Commission),and recommend that the Commission issue an order adopting the settlement contained herein. By entering into this Stipulation, no Stipulating Party shall be deemed to have approved, admitted or consented to the facts, principles, methods or theories employed by any other Stipulating Party in arriving at the terms of this Stipulation. Except as provided in this Stipulation, no Stipulating Party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding.

18. This Stipulation may be signed in any number of counterparts, each of which will be an original for all purposes, but all of which taken together will constitute one and the same agreement.

DATED this 7th day of February, 2022.

PORTLAND GENERAL ELECTRIC COMPANY

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

OREGON CITIZENS' UTILITY BOARD

ALLIANCE OF WESTERN ENERGY CONSUMERS

THE KROGER CO.

WALMART

SMALL BUSINESS UTILITY ADVOCATE

CALPINE SOLUTIONS

PORTLAND GENERAL ELECTRIC COMPANY

/s/ *Jill Goatcher*

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

/s/ Michael P. Goetz

OREGON CITIZENS' UTILITY BOARD

ALLIANCE OF WESTERN ENERGY CONSUMERS

THE KROGER CO.

WALMART

s/ *Diane Henkels*

SMALL BUSINESS UTILITY ADVOCATE

CALPINE SOLUTIONS

PORTLAND GENERAL ELECTRIC COMPANY

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

OREGON CITIZENS' UTILITY BOARD

Corinne Milinovich

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