BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 394

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

OF THE

OREGON CITIZENS' UTILITY BOARD

January 13, 2022

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I. INTRODUCTION

Q. Please state your names, occupations, and business addresses.

A. Our names are Bob Jenks and William Gehrke. Bob Jenks is the Executive Director of the Oregon Citizens' Utility Board (CUB). William Gehrke is an Economist at CUB. Our business address is 610 SW Broadway, Suite 400, Portland, Oregon 97205.

Q. What is the purpose of your testimony?

A. We would like to respond to Portland General Electric's (PGE) Reply Testimony as it relates to deferrals and single-issue ratemaking mechanisms generally, the joint Boardman deferral filed by CUB and the Alliance of Western Energy Consumers (AWEC), PGE's proposal supporting a rider for Faraday cost recovery, and rate spread.

II. SINGLE-ISSUE RATEMAKING MECHANISMS

Q. Please summarize CUB's proposal regarding single-issue ratemaking mechanisms that was made in CUB/100.

A. Since deferrals and single-issue ratemaking mechanisms reduce shareholder cost recovery risk, CUB proposed to adjust overall return on equity (ROE) in future proceedings. At the time of a future general rate case (GRC), for every 1% of revenue requirement that is held within deferrals, a utility's return on equity (ROE) would be adjusted downwards by 5 basis points.[1]

Q. PGE dismisses CUB's proposal. How does CUB respond?

A. First, it is important to recognize that CUB was discussing policy issues and the implications of single-issue ratemaking generally, not revenue requirement in this proceeding. CUB was not proposing to reduce the ROE in this case. CUB supports the stipulation that establishes the ROE. However, it is well established that deferrals and automatic adjustment clauses avoid shareholder risk associated with using GRCs to forecast costs, and therefore reduce the utility shareholder's overall risk profile. Since these mechanisms do not rely on a forecast, they enable dollar for dollar recovery of utility expenditures. ROE is designed to compensate utility shareholders for the cost recovery risk they are incurring in the regulatory process. Therefore, common sense would suggest that there is a threshold number of single-issue ratemaking mechanisms that would require a reduction in ROE. The more single-issue ratemaking mechanisms, the greater the cost recovery certainty. The greater the cost recovery certainty, the less risk that shareholders incur.

[1] UE 394 – CUB/100/Jenks/13.

CUB proposes that the Commission examine the level of revenue that a utility gets through deferrals and automatic adjustment clauses and adjust the ROE when the level of revenue it receives from these lower risk ratemaking tools exceeds certain predetermined levels. CUB believes this should be an ongoing mechanism to enable utilities to adjust to it. Some might prefer a lower ROE which comes with a lower risk and others might not. In Opening Testimony, CUB proposed that, for every 1% of revenue requirement that is held within deferrals, a utility's ROE will be adjusted downwards by 5 basis points. Therefore, in this context, PGE's ROE would be adjusted downward in a future rate proceeding if they exceed the 1% threshold of risk reduction.

Q. Please explain the relationship between deferrals and risk?

A. Deferrals allow tracking of costs for potential dollar for dollar recovery. While there is a prudency risk, and risk that the Commission could find that the amount in a deferred account should be subject to sharing, there is little additional risk. Unlike changes in costs that are reviewed in a GRC, deferrals are not subject to regulatory lag. By filing a request to track a cost via deferred accounting, the utility eliminates regulatory lag by tracking that cost from that date forward, regardless of when the Commission reviews the cost. Further, the utility enjoys interest accruing at its authorized rate of return while the deferral is tracking costs—it essentially profits while costs are being incurred to the account.

Compare that to the regulatory lag when a utility identifies a cost increase, where the Company must wait until the Commission completes a review of a GRC application based on a forward-looking test year. While deferrals do not have any forecast risk, traditionally, cost recovery comes from a rate reflecting a forecast of costs and revenues. Mild weather, for example, can reduce revenues and prevent the full recovery of the expenses (and of course, mild weather also reduces expenses). Extreme weather can increase revenues and lead to over collection of the expense. The regulatory theory is that this is a two-sided risk that will balance over time. For deferrals, cost recovery is independent of that forecast. If mild weather prevents full recovery, the remainder of the deferral is recovery in the succeeding rate period.

The same is true of automatic adjustment clauses which, in a sense, are just multi-year on-going deferrals. These mechanisms reduce risk and stabilize earnings and, therefore, should be reflected in the ROE.

Q. What is the impact of this reduced risk?

A. Utilities respond to incentives. While utilities exist to provide reasonably priced, reliable service, utility executives and employees must answer through their Board of Directors to their shareholders who are expecting to profit from their utility stock holding. If you give a utility the opportunity to earn a profit while reducing risks that would otherwise reduce or eliminate that profit, it is within their fiduciary obligation to take that opportunity. For-profit corporations like monopoly utilities must maximize profit for shareholders. Failure to do so may result in shareholder litigation and liability. This is not a criticism of their motives, just an acknowledgment that they respond to incentives. Deferrals and automatic adjustment clauses create different incentives than ratemaking through GRCs. However, it beyond merely different—it is problematic to customers.

Q. Why is this a problem for customers?

A. Utilities are compensated for the risk that shareholders take. This is written into Oregon law and is the basis for Supreme Court rulings on just and reasonable rates.[2] Shareholder returns are required to relate to the risk that shareholders are taking. When a utility is allowed to reduce its risk significantly without a downward adjustment to shareholder returns, customers are being overcharged.

Q. How should the Commission proceed?

A. CUB's proposal in this proceeding is a reasonable solution to the dilemma posed by the shifting risk regime wrought by single-issue ratemaking mechanisms. CUB urges the Commission to adopt its proposal on a going forward basis due to the use of single-issue ratemaking mechanisms and their effect on utility shareholder risk.

III. BOARDMAN DEFERRAL

Q. Please summarize your testimony on this subject.

A. CUB continues to recommend that the Commission order the amortization of the Boardman deferral filed by CUB and the Alliance of Western Energy Consumers (AWEC) over three years for return to customers. Under established Commission precedent, the Commission has broad discretion on the parameters of the use of an earnings test. Further, while we are not attorneys, it is our understanding that

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[2] *See* UE 394 – CUB/100/Jenks/9.

failure to pass the amounts in the Boardman deferral to customers may be illegal under Oregon's ORS 757.355 "used and useful" statute.

Q. What is the Boardman Coal Power Plant?

A. The Boardman Coal Power Plant (Boardman) was a 550 MW coal-fuel power plant, located in Morrow County, Oregon. Boardman was placed into service in 1980 to serve PGE's customers. Portland General Electric was the primary operator of the plant, and PGE's ownership interest in the facility has varied over the life of the power plant. Boardman was primarily operated as a base-load resource for PGE's customers.

Q. What was the expected terminal life of Boardman in the 2005 depreciation case?

A. Portland General Electric assumed a terminal life for Boardman of 2040 in the 2005 UM 1233 deprecation case.[3] According the Company's filing at the time, these termination dates were based on the judgement of PGE's generation engineers, and these engineers considered design lives, equipment condition, capacity factors, heat rates, fuel supply, future fuel costs, emission standards, and competing technologies.[4] In the 2005 deprecation case, depreciation rates were set such that Boardman Coal Plant was scheduled to be terminated in 2040.

Q. What was the Company's plan around Boardman in its 2007 Integrated Resource Plan (IRP)?

A. In the Company's 2007 IRP initial filing, the Company noticed parties that Boardman would be subject to an assessment of sources pursuant to the Regional

[3] UM 1233 *Detailed Deprecation Study of the Electric Properties of the Company*, Page 23-24.
[4] *Id.*

Haze rule best available retrofit technology process.[5] That is, the plant would need to be retrofitted or potentially closed early to comply with the Regional Haze rule.

Q. What is the Regional Haze rule?[6]

A. The Environmental Protection Agency put into place the Regional Haze rule in 1999. The rule requires each state to submit their regional haze implementation plan to meet regional haze requirements. The EPA requires Oregon to adopt and implement a plant that will reduce visibility impacts in Class I Areas to background levels by 2064.

Q. In the 2007 IRP planning process, what was PGE's plan for Boardman?

A. The Company's plan was to continue to run the Boardman plant until 2040. In its filing, PGE stated that this date was approved by Commission in the Company's most recent 2005 deprecation case.[7] The Company also stated that their engineering group and Boardman plant operators were comfortable with this assessment of the 2040 closure date and noted that Boardman was not operated heavily in the first decade of its life.[8]

Q. What happened in 2009 around the Regional Haze requirements for Boardman?

A. In June 2009, The Oregon Department of Environmental Quality (DEQ) adopted an Oregon Regional Haze Plan. The 2009 plan required PGE to install environmental controls at the Boardman coal power plant in order to continue

[5] LC 73 – PGE Integrated Resource Plan – Chapter 6. Environmental Assumptions, Page 87-88.
[6] https://ndep.nv.gov/air/planning-and-modeling/regional-haze-and-bart
[7] UM 1233.
[8] LC 73 – PGE Integrated Resource Plan – Chapter 6. Environmental Assumptions, Page 96.

operating the plant, for the purpose of reducing visibility-impairing emissions. For the Boardman coal plant, the facility was subject to nitrogen oxides (NOx), sulfur dioxide (SO_2) and particulate matter (PM) limits.

Q. What was PGE's initial plan to meet environmental emissions limits for Boardman in the 2009 IRP?

A. Portland General Electric planned to consider running Boardman until 2040. In order to comply with DEQ emission requirements, PGE was planning to invest $510.406 million in capital to install retrofit technology in order to continue operating Boardman.[9] The Company performed a portfolio analysis to support its investment. The Company evaluated four portfolios, with four different plant run through dates (2040, 2017, 2014, 2011). In its initial filing, PGE stated that the 2040 operation date was the best portfolio for customers on a risk and cost basis.

Q. Did Portland General Electric update the 2009 IRP? What changes did it make to its decision around Boardman?

A. Later in the 2009 IRP proceeding, PGE provided an IRP update where it evaluated a new portfolio, which had a more limited emissions control upgrade package, but limited Boardman to operating until 2020. In the 2009 IRP addendum, PGE, as the result of new portfolio analysis, found that closure of Boardman in 2020 was the best action for customers, based on portfolio risk and costs metrics. This resource option would have required the Oregon DEQ to change its emission rules around Boardman. In November 2010, the Commission

[9] At the time, PGE owned 65% of Boardman. CUB expects that PGE would have been responsible for 65% of the costs associated with Boardman. Therefore, approximately 331 million in capital would have been recovered from PGE's customers through traditional ratemaking.

acknowledged PGE's plan to operate Boardman until 2020. In December 2010, the Oregon Environmental Quality Commission approved new emissions rules that allowed PGE to comply with regional haze rules, while closing Boardman in 2020.[10]

Q. What was the regulatory process like in the 2009 IRP?

A. There was significant engagement in the 2009 IRP process, with labor, environmental groups, consumer advocacy organizations, and Staff all offering comments to the Commission about Boardman's operation. Several government officials and business chambers also provided comments on Boardman in the 2009 IRP proceeding. While Boardman was being evaluated in response to Regional Haze requirements, parties discussed the plant's greenhouse gas emissions when evaluating future options. At that time, Boardman was largest site source of carbon emissions in the state of Oregon. When presenting the 2020 closure date for Boardman, PGE stated that "[c]losing the plant entirely in 2020, ending all plant emissions 20 years ahead of schedule and significantly reducing Oregon's greenhouse gas emissions by ending the use of coal to generate electricity in the state."[11]

Q. What did PGE state about the Boardman coal plant retirement in reply to testimony in this proceeding?

A. The Company stated, "[t]here is nothing exceptional or unpredictable about the Boardman plant retiring as scheduled."[12]

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[10] CUB Exhibit 401.
[11] LC 48 – PGE 2009 Integrated Resource Plan – Addendum, Page 1.
[12] UE 394 – PGE / 2300 / Tooman – Batzler / 13 / Lines 12-14.

Q. What did the previous Commissioners say about PGE's plan to close Boardman in 2020 versus 2040?

A. Commission Order No. 10-457, Page 15, states "We consider [PGE's 2020 closure plan] to be the superior option (1) it is a low-cost option for ratepayers; (2) it mitigates the risk of future carbon regulation by closing the plant at the end of 2020[.]" When discussing the 2040 operation date, the Commission stated "the [2040 Boardman plan], which requires $510 million investment in pollution control equipment in order to operate the plant through 2040, is too costly and too risky. The risk of future carbon regulation, whether it take the form of cap-and-trade regulation, carbon taxation, or the mandated closure of specific coal plants, makes this an inferior option for ratepayers."

Q. Is the closure of Boardman in 2020 exceptional?

A. Yes. To provide evidence for this statement, CUB will use use language from Portland General Electric itself. When PGE received approval for its 2009 integrated resource plan, PGE's CEO Jim Piro stated "This represents a **major milestone** for PGE, our customers and Oregon's Energy Future. This plan responsibly addresses the future energy needs of our customers and strikes a sensible balance between customer costs and risks and environmental impacts and sustainability."[13] When Boardman was closed in October 2020, PGE's CEO Maria Pope stated, "PGE's Boardman closure is a **major step** on our path to meeting Oregon's greenhouse gas emissions reduction goals and transforming our system to reliably serve our customers with a cleaner, more sustainable energy

[13] CUB Exhibit 402, emphasis added.

mix."[14] The 2020 closure date was clearly a big deal for the Company, and committing to closing it early in 2020 required both heavily parsing DEQ rules to find a good outcome and utilizing creative ratemaking mechanisms like accelerated depreciation—which raised short-term costs for PGE customers—to make it happen. Retiring a generating plant 20 years early is significant.

Q. What does the closure of Boardman signal to CUB?

A. Together with the enactment of the Renewable Portfolio Standard in 2007, it is CUB's position that the Company scheduled closure of Boardman in 2020 marks a major milestone in the the clean energy transition for Oregon electric utilities.

Q. Concurrently with the 2009 IRP process, what regulatory process did PGE undertake?

A. Ten days after filing the initial 2009 IRP, PGE filed a depreciation case for its electric property in 2009 before the Commission.[15] Due to the uncertainty around the future operation of Boardman, PGE included two bookend scenarios for the operation of Boardman (2014 and 2040).

Several months after filing the depreciation case in 2009, PGE filed for a general rate case in 2010.[16] In the 2010 rate case initial filing, Portland General Electric assumed a revenue requirement associated with a 2040 life for Boardman.[17] The Company requested a separate schedule tracker (PGE Schedule 145) to recover the accelerated depreciation associated with Boardman, if Boardman's operation

[14] CUB Exhibit 403 emphasis added.
[15] *See* UM 1458.
[16] *See*, UE 215 – General Rate Case for Portland General Electric.
[17] UE 215 – PGE/300/Tooman – Tinker/26.

is scheduled to closed prior to 2040.[18] PGE received approval for Schedule 145 in UE 215.

Q. What was the outcome of Boardman's depreciation rate in UM 1458?

A. Staff and PGE agreed in the 2009 Deprecation case, UM 1458, to keep Boardman depreciation rates associated with a 2040 terminal date, in place until an IRP proposal was adopted.

Q. Was PGE allowed to accelerate deprecation associated with Boardman outside of a general rate case?

A. Yes. The 2010 PGE rate case depreciation expense was based on operation of Boardman until 2040. In the third quarter of 2011, under the terms of Schedule 145, Portland General Electric was allowed to accelerate Boardman outside of a general rate case. From 2011 to 2013, PGE used Schedule 145 to collect accelerated deprecation through Schedule 145.

Q. The Company states "There is nothing exceptional or unpredictable about the Boardman plant retiring as scheduled and remaining in rate base until new rates are set—this is standard ratemaking practice"? Has PGE proposed a traditional ratemaking process for Boardman?

A. No. PGE used separate trackers to recover the accelerated deprecation associated with Boardman between 2011 and 2013. As discussed in the prior section, separate trackers like these represent a departure from traditional ratemaking. AWEC and CUB filed the Boardman deferral in this discrete to appropriately match PGE's earlier efforts and track the revenue requirement impacts of the

[18] UE 215 – PGE/300/Tooman – Tinker.

closure of the plant. Approving amortization of the Boardman deferral would match the process that PGE used to capture accelerated depreciation via separate trackers, and would result in an equitable outcome for Oregon's customers who paid off Boardman in an accelerated manner—increasing short-term costs.

Q. What would applying traditional ratemaking to Boardman look like?

A. That is a little hard to say, because retiring large generating plants 20 years before the end of their useful life is not standard practice. The clearest precedent is the Trojan nuclear plant which was retired in 1993. In that case, the Commission conducted a net benefits test and allowed partial recovery of the outstanding undepreciated investment[19] and the Oregon Court of Appeals found that the Company could continue to charge customers for the outstanding capital investment (return of) but could not charge them a rate of return (return on). Although this precedent is on point, PGE is not proposing that the Trojan precedent be applied in this case, which is not surprising since that precedent led to a partial disallowance and prohibited charging customers a rate of return on the undepreciated balance when the plant retired.

CUB recognizes that applying a net benefits test and denying utilities a rate of return on unamortized balances are potential barriers to utility shareholders agreeing to support the retirement of coal plants. CUB has supported accelerated depreciation to decarbonize utility systems even though this is a departure from traditional ratemaking. But relying on accelerated depreciation to protect

[19] OPUC Order No 95-322.

shareholders increases the need for the Boardman deferral. If Boardman had operated until the end of its expected useful life, then the amount of depreciation and return on ratebase left in base rates at the end of that life would be a small number – much smaller than the current levels which reflect the plant's retirement and acceleration of cost recovery. Allowing PGE to keep Boardman's accelerated depreciation in rates after the Boardman ratebase was fully recovered creates a new barrier to the transition to clean energy.

Q. How does this create a barrier to the transition to clean energy?

A. Oregon utilities have a number of fossil fuel facilities that provide power to customers, including a significant number of coal plants. Using trackers and accelerated depreciation to facilitate their closure is a way to protect shareholders from the impacts of this transition. But allowing a utility to earn a profit from customers on a coal plant that is closed and has been fully paid for, particularly when the utility is able to use an automatic adjustment clause to recover the costs associated with the clean energy replacement, is not fair. And unfair rate treatment may lead to some customer groups opposing this transition or fighting elements of this transition. Regulatory policy that supports a transition to clean energy should be fair to both customers and shareholders. CUB recognizes that accelerated depreciation can be a helpful tool to reduce the regulatory risk to shareholders associated with this transition. But this should be balanced by also protecting customers from being overcharged for the costs of this transition. The Boardman deferral creates a fair balance. Shareholders get to fully recover their full investment and receive a rate of return on their undepreciated investment and customers are not required to pay more than the actual costs associated with the retiring plant.

Q. Why does CUB believe that its reasonable for the Commission to approve and amortize the Boardman Deferral?

A. The authorization and amortization of the deferral will match the costs and benefits of the Boardman coal plant. While I am not an attorney, this appears to be consistent with the language in the deferral statute seeking to "match appropriately the costs borne by and benefits received by ratepayers."[20] Customers did not benefit from the generation of electricity at the Boardman past October 2020, yet PGE rates continue to include the recovery of costs past this period. PGE's customers had completed paying off PGE's investment in Boardman on an accelerated timeline. The amortization of the Boardman deferral also allows for consistent treatment of coal plants in customer rates as these power plants are retired. Both Idaho Power and Pacific Power plan on no longer charging customers for costs associated with closed power plants.

PGE has also used Schedule 145 to recover the costs associated with the retention and severance of PGE's employees at Boardman outside of a general rate case process. As of June 2020, PGE's customers had paid for 14 million in severance and retention costs to PGE.[21] By rejecting the Boardman deferral, PGE is essentially asking customers to fund retention and severance benefits for Boardman employees, while allowing PGE to take advantage of reduced labor

[20] ORS 757.259(e).
[21] CUB Exhibit 404.

costs. These cost savings were funded by customers, not PGE. CUB believes that customers should receive the benefits of decreased labor costs in their cost of service, and that the deferral adequately resolves this.

Q. What is ahead for Oregon?

A. The Oregon legislature has signaled to the electric utilities that it would like to transition away from coal. SB 1547 requires the electric utilities to no longer include the costs of coal in rates past 2030. While Portland General Electric only has ownership of two coal sites (Colstrip and Boardman), Pacific Power is transitioning a large portion of its generation fleet away from coal.

Decades ago, coal power plants were prudent investments to meet electricity needs. However, Oregon greenhouse policy goals are forcing Oregon utilities to get out of coal plants on an accelerated basis. It was unprecedented for a state legislature to ban a specific type of fuel for electricity. To fund this transition, customers are going to have to pay for the accelerated costs associated with moving out of a coal plant early to ensure that utilities are allowed to recover prudently incurred costs. CUB asks to Commission to recognize the price impact of accelerated depreciation from transitioning away from coal plants, and to not enable rates that charge customers for closed coal plants. This transition is once in a generation, and customers are doing their part to fund this transition.

Q. PGE is opposing CUB and AWEC's proposal to amortize the Boardman deferral. What is CUB's response?

A. CUB is concerned that PGE's view of generation rate base is entirely one-sided with no regulatory lag when investments are made, and a great deal of regulatory lag when investments no longer provide service to customers. To the best of our knowledge, PGE has not taken regulatory lag on a major generating asset since Mr. Jenks has been working for CUB. Going back to Coyote Springs in 1995, PGE has avoided regulatory lag on Coyote Springs,[22] Carty,[23] Tucanon,[24] and Port Westward 1[25] and 2.[26] Because the Renewable Adjustment Clause AAC allows cost recovery of renewable resources without any regulatory lag, this pattern will continue into the foreseeable future.

PGE, however, does not believe that regulatory lag should be avoided on the back end for customers, after an asset has been fully recovered. Its advocacy in this proceeding demonstrates this.

Mathematically, if no regulatory lag is allowed on the front end, and regulatory lag is allowed on the back end, then customers will overpay a utility for the return of and return on generation investment. We are not lawyers, but we understand that Oregon law prohibits charging customers for utility investments that are "not presently used to serve customers." It seems like requiring customers to systematically overpay may run afoul of Oregon's requirement that customers

[22] OPUC Order No 95-322.
[23] OPUC Order No. 15-356.
[24] OPUC Order No. 14-422.
[25] OPUC Order No. 07-015
[26] OPUC Order No. 15-356.

cannot be charged for rate base that is not currently providing service to customers. In addition, our understanding of the Trojan litigation was that it established that utilities cannot earn a return on capital investments that are no longer providing service. CUB will address these issues later in its brief.

Q. PGE's claims that once an earning test is applied, amortization of the deferral will not be warranted. How do you respond?

A. Our understanding is that the deferral statue requires "a review of the utility's earnings," but that there is a great deal of discretion in applying an earning review. Rather than a narrow look at whether overall earnings were below or above authorized earnings, the required earnings review is meant to consider the circumstances of the deferral. In UM 995, the Commission found that while the utility was underearning, it was reasonable in the circumstances to recognize that a 250-basis point deviation from forecasted earnings still reflected earnings that were within the reasonable range. In addition, the Commission adopted sharing percentages for earnings outside that range, concluding that even a deviation of 400 basis points does not rise to the level of confiscatory ratemaking.[27]

While the circumstances of that case were different than this one – it dealt with replacement power costs during the Western Energy Crisis – the recognition that the Commission has wide discretion when appling an earnings review, that an earnings test reflecting authorized rate of return is not required, and that the

[27] OPUC Order No 01-420.

circumstances that led to the deferral are important factors that need to be considered in that earnings review.

Q. What are the circumstances of this case that should be considered?

A. When it comes to the application of an earnings review, CUB recommends that the Commission recognize this systematic overcollection built into Oregon ratemaking and recognize Oregon rates are unbundled: separated into generation, transmission, distribution, and customer related costs. PGE has eliminated regulatory lag for major new generating investments and the Commission should consider whether an earnings review should be limited to generation, whether allowing amortization is necessary to ensure that ratemaking is fair and balanced and what is the reasonable range of generation earnings that would prevent a balanced treatment of regulatory lag of major plant investments. CUB will address this issue further in briefing.

Q. Does CUB accept PGE's revised revenue requirement calculation for Boardman?

A. Yes. PGE noted that the revenue requirement associated with Boardman is 66.5 million. After reviewing the workpapers provided by PGE, CUB finds the number to be reasonable. However, the Boardman application is a joint application with CUB and AWEC; CUB may revise this position after to reviewing intervenors testimony on this issue.

Q. PGE claims that it has had to absorb $157 million in plant related regulatory lag between 2019 and 2021. Does this change your view?

A. No, it does not. First, it is important to recognize that PGE is discussing all regulatory lag, not generation regulatory lag. Second, PGE is simply showing that rate base is increasing, but does not recognize that there is also load growth and revenue growth. In fact, some of this additional ratebase is directly related to load growth that produced additional revenue. Third, PGE is including 2019 and 2020, where the earning review should be limited to the deferral period which does not include 2019 and only includes a few months of 2020.

Q. What impact does including all regulatory lag, not just generation have?

A. CUB Exhibit 405 shows that PGE's $157 million in plant-related regulatory lag is calculated by comparing rate base in 2019, 2020 and 2021 to 2018 and totaling the numbers for three years. This total figure for rate base includes all capital investments, from an office computer to a distribution pole. CUB has never argued that PGE does not need to make on-going investments in its system and that those investments have some level of regulatory lag on both the front and the back end of their useful lives. However, the Company has eliminated regulatory lag from major generating investments but wants to subject those facilities to regulatory lag after they no longer provide service. This is patently unfair. The fact that there is regulatory lag for line transformers and other portions of the distribution system is not a significant reason to have generation rate base treated unfairly.

Q. What is the impact of load and revenue growth?

A. Simply looking at the growth in rate base and claiming it demonstrates regulatory lag is misleading. Much of this additional capital investment was offset by load growth. In 2018 PGE's load was 19,221,496.[28] PGE is projecting its 2022 load at 20,497042,[29] an increase of 6.6%. In 2018, PGE had 881,766 customers.[30] PGE is projecting 922,096 customers in 2022,[31] an increase of 4.57%. In 2018, PGE's revenue from retail energy customers was $1,789,303,774.[32] PGE is projecting 2022 retail revenue of $2,042,134,129[33] at current rates, an increase of 16%. In fact, this load growth means that customers who came on the system after it closed in 2019 are paying Boardman-related rates without ever having received a benefit from the plant. In addition, some of this increase in rate base is directly offset by revenue. When a new customer is added to the system, PGE's line extension policies guide how much rate base investment is associated with that customer. Because the investment is capitalized and spread over decades and the new revenue is immediate with service to the customers, it is expected that the new customer will more than offset the revenue requirement impact of the capital investment associated with its line extension allowance even in its first year.

Q. PGE claims that what CUB and AWEC propose is a change in Commission policy and should not be done without advanced notice to the utility. How do you respond?

A. It is a bit of a stretch to label our proposal as a change in policy. Major generating assets are not retired frequently. The last major generating asset of PGE's that was retired was the Trojan nuclear plant in 1993. In that docket, the

[28] OPUC 2018 Utility Statistics.
[29] UE 394 – PGE Exhibit 1202.
[30] OPUC 2018 Utility Statistics.
[31] UE 394 – PGE Exhibit 1202.
[32] OPUC 2018 Utility Statistics
[33] UE 394 -- PGE Exhibit 1202

Commission subjected the retirement to a net benefits test and the result of that decision led to litigation that lasted longer than the plant had been in service. In addition, CUB and AWEC are arguing for similar treatment to how retired coal plants are treated for Idaho Power and PacifiCorp. Finally, PGE's suggestion that the Commission has to give a utility advanced notice to change policy seems bizarre, when PGE always asks for policy changes when it has a general rate case without notifying stakeholders. In this case, PGE addressed policy changes related to its decoupling mechanism and to the Level III storm mechanism without any prior notice. Indeed, Idaho Power unilaterally proposed similar ratemaking treatment for its share of Boardman well before AWEC and CUB filed the deferral. PGE cannot reasonably say it was not noticed.

CUB would also like note that there is considerable gap in rate case planning information and expertise between intervenors and PGE. PGE's regulatory affairs department has access to subject matter experts (engineering, accounting, legal and corporate employees) to enable it to maximize its ROE in the ratemaking process. CUB has limited access to the Company's books between general rate cases and lacks the resources to look at every single issue presented in a general rate case. The Commission should not consider the Boardman deferral to be bad regulatory policy because CUB failed to foresee a ratemaking problem several years into the future. When CUB realized the ratemaking implications of accelerated depreciation and the closure of Boardman on PGE's customers, CUB's only option was to file a deferral to track these expenses for customers.

Q. What is CUB recommendation around Boardman?

A. CUB recommends that the Commission approve and amortize the Boardman deferral over three years. CUB believes that failure to pass back the costs contained in the Boardman deferral is likely illegal and will address this issue further in briefing.

IV. FARADAY REPOWERING TARIFF RIDER

Q. PGE is proposing that it be allowed to use a tariff rider to bring its Faraday into rates at the end of the test year. Does CUB support their proposal?

A. No. PGE consistently wants to bring new generating investment into rates without regulatory lag. PGE consistently files a general rate case to conclude before a major generating asset come on line and proposes allowing the new investments to be tracked into rates when they come on line. It has been true for Port Westward 1,[34] Tucannon,[35] Port Westward 2,[36] and Carty.[37] Faraday was supposed to be an exception for PGE. According to PGE's Opening testimony, the investment was supposed to in service March 2022.[38] This project has been delayed numerous times. Today, PGE hopes to complete the plant by the end of the year. This means that the plant will hardly operate within the test year, which is the basis for our analysis of costs and revenues in this case.

Q. Please explain.

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[34] OPUC Order No 07-015.
[35] OPUC Order No. 14-422.
[36] OPUC Order No. 15-356.
[37] OPUC Order No. 15-356.
[38] UE 394 - PGE/700/Jenkins – Cristea/5.

A. The rate setting process in Oregon is based on examining a future test year. Utility costs and revenues are forecast for that test year and that forecast of costs and revenues is the basis for the rates that are set. This rate case did not examine 2023, which now represents most of Faraday's first year of operation. Rate recovery for Faraday should now be based on a 2023 test year.

Q. Why is examining the proper test year important.

A. In a general rate case, rates are established based on a forecast of overall costs and revenues associated with a specific test year. But like all forecasts, the estimates for both costs and revenues are wrong. Because ratemaking is about setting a rate that allows for overall costs to be recovered, not individual costs, as the forecasts from the rate case get stale, it is difficult to identify how much rates should change to allow recovery of an individual element of revenue requirement. It is not wise to assume that the forecast of 2022 costs and revenues reasonably represents costs and revenues for 2023. In addition to forecast error, the 2022 test year does not account for load in 2023. PGE could have new customers of sufficient size expected to be added in 2023 that are not accounted for in the 2022 test year.

For example, let's assume a new capital investment has a first-year revenue requirement of $30 million. The last rate case was 11 months ago, and it is clear that the load forecast underestimated weather normalized load by 1%, or more than 200,000 MWh. Recognizing that the average price across all customer classes is more than 10 cents per kWh[39] means that PGE has more than $20 million in additional revenue. While this additional load would likely produce additional power costs, much of it would represent an over collection of fixed costs, recovery of which was based the underestimated load forecast. The issue is not whether the utility should be able to seek recovery of the $30 million revenue requirement associated with the investment, but how much do rates need to change in order to allow the utility the opportunity to recover the cost.

Q. What conditions does the Commission place on trackers?

A. The Commission has generally put time limits which require that they come online by the middle of the test year. In addition, the Commission has required that there be some level of review to ensure that the test year forecast is still reasonably accurate.

Q. Please explain the conditions that were placed on Port Westward's tariff rider.

In the case of Port Westward, the plant was originally scheduled to become operational on March 1, 2007. The Commission allowed an unconditional tariff rider if the plant was operational by April 30 but required the opportunity for parties to requests a re-examination of costs if the plant came online after April 30 but before September 1. If the plant came online after September 1, the company would have to file "an entirely new rate case."[40] The plant came online on June 11, 2007,[41] midway through the 2007 test year.[42]

[39] OPUC, 2020 Oregon Utility Statistics.
[40] OPUC Order No 07-015.
[41] OPUC Order No 07-273.
[42] UE 184, PGE/100/Lesh/2.

Q. Please explain the conditions placed on a tariff rider for Port Westward 2 and Tucannon.

A. With Port Westward 2 and Tucannon, an unconditional tariff rider was limited to 3 months[43] after the January 1 rate effective date. If the plants came online within 60 days after that period (5 months into the test year), it was subject to conditions that allowed Staff and intervenors a period time to establish sufficient cause to warrant the reopening of the rate case to determine whether there are cost reductions that should offset costs associated with the plant.[44] If the plant came online more than 5 months after the rate effective date, PGE was required to make a new filing. Port Westward was placed in service on January 26, 2015, within the first month of the test year[45] and Tucannon came online in December 2014, before the test year.

Q. Please explain the ratemaking treatment of Carty.

A. With the Carty plant PGE was again allowed a tariff rider with an explicit expiration date which corresponded to 7 months into the test year.[46]

Q. How do these compare to what PGE is asking for with Faraday?

A. Faraday won't be placed into service until, at best, the 4th quarter of the test year.[47] PGE is asking for an unconditional tariff rider based on a 2022 test year for a plant whose first year of operation will in large part be in 2023. This is inconsistent with previous orders, where the Commission has allowed tariff riders

[43] OPUC Order No. 14-422.
[44] UE 283 – Staff Exhibit 902.
[45] OPUC Order No. 15-077.
[46] OPUC Order No. 15-356
[47] UE 394 – PGE/1900 Bekkedahl – Cristea / 27.

with a deadline that was in the middle of the test year. While PGE would like to keep this rate case open and be able to fold Faraday into this case, the history of tariff riders suggests that Faraday should not be provided a tariff rider. The costs associated with the Faraday project should more appropriately be evaluated with a 2023 test year that examines 2023 costs, 2023 loads, and 2023 revenues.

Q. Does CUB support PGE's proposal for a tariff rider for Faraday?

A. No. The Commission has placed limits on previous tariff riders that if applied to Faraday would preclude it from being eligible for such treatment. Faraday's revenue requirement impact should be measured based on a 2023 test year. The Commission should reject PGE's request for a tariff rider.

V. RATE SPREAD

Q. What is CUB's position on rate spread?

A. In Opening Testimony, Staff recommend that no rate schedule receive a rate decrease. Staff also stated, "[i]n past rate cases, the Commission has supported no rate decreases for some schedules while rate increase for other schedules."[48] This is in line with well-established Commission precedent in which the "Commission has adopted a policy that precludes any customer class from receiving a rate reduction in the face of an overall increase in revenue requirement."[49] CUB agrees with this policy and proposes that rates be subject to 0% floor. Since parties have agreed to an overall revenue requirement in a joint stipulation, CUB recommends that revenue from the CIO be used to establish a 7% rate cap[50] to

[48] UE 394 – Staff /1400/St. Brown/18.
[49] OPUC Order No. 96-175 at 5-6.

mitigate general rate case increases in this case. CUB's proposal makes movement towards the cost of service, has large customers experience no increase in this proceeding, and mitigates price increases for several customers classes, particularly small commercial and residential customers.

Q. Please summarize the projected 2022 Cost of Service rate impacts of CUB's proposal.

A. Table 1, below, summarizes the base rate impact of CUB's proposed rate spread.

Table 1

Estimated Cost of Service Base Rate Impacts inclusive of Schedules 122, 125, 131, and 146[51]

Schedule	Base Rates
Residential (Schedule 7)	7%
Small Nonresidential (Schedule 32)	7%
31-200 kW (Schedule 83)	3.3%
201-4,000 kW (Schedule 85)	0%
Over 4,000 kW (Schedule 89)	0%
100 MWa (Schedule 90)	0%

Q. Why is CUB's recommendation reasonable?

[51] Schedule 131 – Oregon Corporate Activity Tax is included. With the recent stipulation, CUB considers state taxes to be a component of base rates.

A. CUB believes that the Commission should continue its policy of not having rates for customer classes moving in opposite directions. Marginal cost studies are theoretical and vary in results based on the assumptions established in the study. Marginal cost studies should be used to inform and guide rate spread decisions; this means that marginal cost study should not be used to dictate rate spread decisions.

Q. What complicates CUB's testimony on this subject?

A. Many of the parties to this case have agreed to a specific revenue requirement under the terms of a joint stipulation. However, intervenor testimony evaluated rate spread on a different rate increase amount.

Q. What is PGE's current position on rate spread?

A. PGE believes it is appropriate for one schedule to receive a rate decrease while the overall case presents a rate increase. The Company also states that Schedule 90 customers have experienced higher than average price increase from the past few Annual Update Tariff (AUT) proceedings.[52] Therefore, PGE finds it reasonable to decrease rates for Schedule 90.

Q. What is CUB's reaction to PGE's testimony on this subject?

A. In a recent contested general rate case around rate spread, the Commission stated, "we have a longstanding policy of not reducing rates for some customers where rates are increased for other customers… we would apply this policy '[a]bsent compelling evidence that warrants more immediate action.'"[53] In that case, the marginal cost of service study supported a rate decrease for large customers.

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[52] UE 394 – PGE / 2200 Macfarlane – Tang / 27
[53] OPUC Order No. 16-109.

Separate from the marginal cost study, PGE has presented evidence that increases over the past three years from the AUT. In CUB's judgement, is not insufficient evidence to decrease rates for one customer class while increasing it for others. The Commission should require a compelling reason to depart from such well-established precedent.

Q. What evidence contradicts the level of rate changes between 2019-2021?

A. PGE has been subject to several emergencies. In 2020, the Company experienced a historic wildfire. In 2021, the Company experience a historic ice storm event. The incremental costs associated with these events are significant, and PGE sought deferred accounting for these expenses. As explained earlier in our testimony, this means that these deferrals tracked, and PGE plans to recover, expenses from 2020-2021 from customers at a later date. Greater than 90% of the expense related to the deferral are subject to the distribution function. Distribution system costs are allocated primarily to smaller customers. CUB expects that residential customers are going to be charged millions for expenses for emergency restoration costs. Therefore, residential customers facing a significant rate increase in this proceeding will also see rates increased once those deferrals are eligible for amortization.

Q. What else did PGE state about Schedule 90?

A. PGE stated that "Schedule 90 loads are stable, with long term growth and a high load factor energy consumption pattern, which provides a unique contribution to the entire system. All customers benefit from Schedule 90 customers remaining on COS as it provides the additional kWh over which PGE spreads its costs, resulting in lower prices for all customers."[54]

Q. What is CUB's response to PGE's statement?

A. CUB would like to highlight that the Company said, "remain on COS." CUB fails to see a link between the rates established in this general rate case, and Schedule 90 customers receiving service through direct access. CUB does not dispute that Schedule 90 customers remaining on the system is beneficial to all customers because of Schedule 90's load factor. However, Schedule 90 remaining on the system is also good for Portland General Electric's business model. If industrial growth continues on PGE's generation system, all things equal, this will increase PGE's energy and capacity need, which provides PGE with an opportunity to increase profits for shareholders by acquiring additional capital. CUB urges the Commission to follow its established precedent. There is not sufficient justification to depart from established Commission precedent—no rate schedule should receive a decrease in the face of an overall increase.

Q. When calculating the floor/ceiling for customers, did CUB make any adjustments for direct access customers?

A. Yes. CUB excluded the costs associated with long-term transition cost adjustments when calculating the CIO. When a customer opts to participate in direct access service, these customers are subject to 5-year transition cost adjustments. CUB does not consider the costs of transition adjustments to be base

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[54] UE 394 – PGE/2200/Macfarlane – Tang/13.

rates and excluded these revenues from CUB's rate spread proposal because these costs are unrelated to the general rate case.

Q. What is your recommendation?

A. CUB respectfully urges the Commission to adopt its rate spread proposal, detailed in Table 1 above.

Q Does this finish your testimony?

A. Yes.

Portland General Electric

Environmental Quality Commission Gives Final Approval to DEQ Recommendation for Boardman Power Plant

2020 framework allows time to develop replacement resources

PORTLAND, Ore.--(BUSINESS WIRE)-- The Oregon Environmental Quality Commission today approved new rules that allow the Boardman Power Plant, southwest of Boardman, Ore. to meet state and federal environmental requirements with emission control retrofits for sulfur dioxide and oxides of nitrogen over the next ten years and the cessation of coal-fired operations no later than December 31, 2020. The Boardman Plant is operated by Portland General Electric (NYSE: POR).

"These are tough new rules that put Oregon at the forefront of national efforts to reduce emissions from coal-fired power generation," said Jim Piro, PGE president and CEO. "We've worked hard with a broad coalition of Oregon citizens and organizations to gain public support and regulatory approval for an environmentally responsible, workable, cost-effective emissions control strategy and timeline for the Boardman Plant. Implementing these rules won't be easy or inexpensive, but it strikes a good balance of costs and benefits for our state and our customers."

The new controls are expected to reduce NO_X emissions by about 50 percent and permitted levels of SO_2 emissions by 75 percent. A separate set of rules also requires controls to reduce the plant's mercury emissions by 90 percent. All coal-related emissions from the Boardman facility will be reduced to zero with the end of coal-fired operations in 2020. The combined capital cost of the required controls is currently estimated at about $60 million.

The new rules were recommended by staff at the Oregon Department of Environmental Quality, following an extensive public process with two formal comment periods and seven public hearings. The agency also convened a fiscal advisory committee last summer to review the economic impact of various control options. The new rules will be implemented with the following measures:

- Installation of new low-NO_X burners and modified overfire air ports in July 2011 to comply with Best Available Retrofit Technology (BART) standards for oxides of nitrogen.
- Installation of a dry sorbent injection system in July 2014 to comply with BART standards for sulfur dioxide.
- Pilot studies for the DSI system to verify that set SO_2 limits for 2014 and 2018 are achievable.
- Repeal of DEQ's 2009 BART rule, which would have allowed continued operation of the Boardman Plant through at least 2040 with installation of a much more expensive suite of emissions controls.
- Permanent cessation of coal-fired operation no later than December 31, 2020.

DEQ will now incorporate the EQC decision into its state implementation plan for regional haze, which will be forwarded to the federal Environmental Protection Agency for approval.

As operator and majority owner of the plant, PGE will proceed with acquisition and installation of the necessary controls, beginning with the low-NOx burners and mercury controls in July 2011. The company will also engage stakeholders in a comprehensive analysis of potential options to replace the power from the Boardman Plant — or convert the existing plant to a different fuel — as part of its next integrated resource planning cycle.

Adoption of the new rules completes a process that began when PGE volunteered in 2006 to have the Boardman Plant to be the first Oregon facility evaluated under BART guidelines. The utility then submitted an initial analysis and control plan to DEQ in 2007. After DEQ adopted its first BART rule in 2009, PGE incorporated the rule's emissions control requirements into the company's long-term resource plan, but also responded to stakeholder requests for further analysis of an alternative strategy based on a 2020 timeline.

In January 2010, PGE announced that it would pursue a 2020 alternative and then in April submitted an initial 2020 plan to DEQ. The company also modified its integrated resource plan as submitted to the Oregon Public Utility Commission. PGE then updated and strengthened the 2020 plan in August and October, incorporating new technologies and further tightening proposed emissions and operational restrictions to address concerns of regulators and stakeholders.

The OPUC acknowledged the revised 2020 plan in November, noting that earlier closure dates would not allow enough time for the company to secure reliable replacement power.

PGE owns 65 percent of the Boardman Plant. Co-owners include Bank of America Leasing LLC, with 15 percent, Idaho Power, with 10 percent, and Power Resources Cooperative, with 10 percent.

About Portland General Electric Company

Portland General Electric Company is a vertically integrated electric utility that serves approximately 822,000 residential, commercial and industrial customers in the Portland/Salem metropolitan area of Oregon. The Company's headquarters are located at 121 SW Salmon Street, Portland, Oregon 97204. Visit our website at www.PortlandGeneral.com.

Safe Harbor Statement

Statements in this news release that relate to future plans, objectives, expectations, performance, events and the like may constitute "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995, Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements include statements regarding the future operation of the Boardman Power Plant, statements regarding expected emissions reductions in the future, statements regarding estimated costs of emissions controls, as well as other statements containing words such as "anticipates," "believes," "intends," "estimates," "will," "promises," "expects," "should," "conditioned upon," and similar expressions. Investors are cautioned that any such forward-looking statements are subject to risks and uncertainties, including those relating to final regulatory review by the Environmental Protection Agency and the installation, cost and effectiveness of future emissions controls. As a result, actual results may differ materially from those projected in the forward-looking statements. All forward-looking statements included in this news release are based on information available to the Company on the date hereof and such statements speak only as of the date hereof. The Company assumes no obligation to update any such forward-looking statement. Prospective investors should also review the risks and uncertainties listed in the Company's most recent Annual Report on Form 10-K and the Company's reports on Forms 8-K and 10-Q filed with the United States Securities and Exchange Commission, including Management's Discussion and Analysis of Financial Condition and Results of Operations and the risks described therein from time to time.

POR-F

Source: Portland General Electric Company

PGE
Steve Corson, 503-464-8444
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www.twitter.com/pgemedia

Source: Portland General Electric Company

News Provided by Acquire Media

Portland General Electric

Oregon Public Utility Commission Acknowledges PGE Resource Plan

Energy efficiency to meet nearly half of new demand for electricity to 2020

PORTLAND, Ore.--(BUSINESS WIRE)-- The Oregon Public Utility Commission today granted final acknowledgement to Portland General Electric Company's (NYSE: POR) 2009 integrated resource plan. The plan outlines strategies to meet PGE customers' electricity needs over the next 20 years, with a four-year action plan for acquisition of new resources to begin implementing those strategies. The plan is the result of two years of analysis, research and public debate, including extensive input from customer advocates, regulators, energy experts, and other key stakeholders.

"This represents a major milestone for PGE, our customers and Oregon's energy future," said Jim Piro, president and CEO. "This plan responsibly addresses the future energy needs of our customers and strikes a sensible balance between customer costs and risks and environmental impacts and sustainability. It also provides a reasonable transition time for moving away from coal to other sources of energy supply."

The four-year resource acquisition plan targets:

- All energy efficiency measures identified as achievable by the Energy Trust of Oregon — 214 average megawatts — which PGE expects will meet nearly half of PGE's load growth through 2020.
- 122 average megawatts of additional renewable resources to meet Oregon's renewable energy standard requirements on or ahead of schedule.
- Demand-side resources — measures customers can take that can reliably deliver short-term reductions in customer demand to help reduce capacity needs and manage loads during peak periods.
- Additional natural gas-fired generation with state-of-the-art turbines and pollution controls to serve existing demand, meet additional load growth and maintain reliability standards. This would include 300 to 500 megawatts of baseload capacity and 100 to 200 megawatts of flexible peak load resources.
- Short-term and mid-term market purchases.
- Installation of emissions control retrofits on PGE's coal-fired generating plant near Boardman, Oregon, to comply with Regional Haze rules under the Clean Air Act. The commission acknowledged PGE's 2020 plan for the plant, which calls for the initial control retrofits followed by an end to coal-burning at the plant by December 31, 2020. This action is contingent on approval of the 2020 plan by the EQC, which is slated to act on the proposal later this year.
- New transmission capacity to help meet growing energy needs, allow for development of more renewable power projects, and enhance reliability of the electrical grid. PGE has proposed development of a new transmission line called Cascade Crossing, which would bring power generated east of the Cascade Mountains to the Willamette Valley near Salem, Oregon.

The integrated resource planning process, which follows guidelines established by the OPUC, is designed to identify a future portfolio of resources that offers the best combination of cost and risk, taking into account factors such as environmental impacts, fuel supply availability, price volatility, resource diversity, and the ability of available resources to reliably meet demand. Utilities issue integrated resource plans roughly every two years to reflect new technologies, market conditions, and regulatory requirements.

PGE filed its 2009 integrated resource plan with the OPUC in November 2009 and then filed an addendum in April 2010 updating its plans for the Boardman plant. The company will now develop requests for proposals, under the OPUC's competitive bidding guidelines, to seek additional renewable and natural gas-fired generating resources called for in the four-year action plan.

About Portland General Electric Company

Portland General Electric, headquartered in Portland, Ore., is a vertically-integrated electric utility that serves more than 822,000 residential, commercial and industrial customers in Oregon. Visit our Web site at www.PortlandGeneral.com.

Safe Harbor Statement

All statements contained in this press release that are not historical facts are forward-looking statements that are made pursuant to the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. They are not guarantees of future events. Rather, they are based on current expectations, estimates, beliefs and assumptions and are subject to uncertainties that are difficult to predict. As a result, actual events or results may differ materially from the statements made. Forward-looking statements made in this press release include statements regarding the company's energy strategy for future periods, the effectiveness of energy efficiency initiatives in decreasing energy consumption, the anticipated increase in demand for electricity in the Company's service territory, the implementation and outcome of requests for proposals, and the acquisition of additional capacity to meet such demand. These forward-looking statements are based upon our assumptions about and assessment of the future, which may or may not prove true, and involve a number of risks and uncertainties including, but not limited to, risk factors detailed in the Company's most recent Annual Report on Form 10-K, the Company's reports on Form 10-Q and other filings with the United States Securities and Exchange Commission.

POR-F
Source: Portland General Electric Company

Steve Corson, PGE, 503-464-8444

Source: Portland General Electric Company

Portland General Electric announces end to coal-fired power generation in Oregon

Portland, Ore.– Portland General Electric Company (NYSE: POR) today announced it has permanently shuttered its Boardman Generating Station in Eastern Oregon's Morrow County. The closure fulfills a groundbreaking agreement PGE reached with stakeholders, customer groups and regulators in 2010 to significantly reduce air emissions from power production in Oregon by ending operations at Boardman 20 years ahead of schedule and transitioning to cleaner energy resources. Boardman is the only coal-fired power plant in Oregon. PGE has a 90 percent ownership share of the plant. Idaho Power owns the remaining 10 percent.

"Our customers are counting on us to deliver a clean energy future," PGE President and CEO Maria Pope said. "PGE's Boardman closure is a major step on our path to meeting Oregon's greenhouse gas emissions reduction goals and transforming our system to reliably serve our customers with a cleaner, more sustainable energy mix."

Boardman's closure has been factored into PGE's resource plans since 2010, so the company could take steps to ensure there'll be enough electricity to continue reliable electric service to customers after the plant's shutdown. No single generator will replace the facility. Instead, a mix of resources including five-year contracts with the Bonneville Power Administration, Washington's Douglas County PUD, and other independent suppliers has been added to PGE's energy portfolio to meet near-term needs; a request for proposals for additional long term, non-emitting capacity resources is in the planning stages and is expected to be conducted next year.

The company is also bringing online energy storage, new renewable resources, and new distributed resources like demand response (when customers help balance the grid by volunteering to shift energy use during peak times) to create a cleaner, more resilient power system for the future.

One notable new renewable power resource that will help serve PGE customers and contribute to a healthy economy in the Morrow County community going forward is Wheatridge – a facility PGE is building with NextEra Energy Resources just south and east of Boardman, with 300 megawatts of wind and 50 megawatts of solar, augmented by 30 megawatts of battery storage. PGE will own part of the wind resource and purchase the rest of Wheatridge's output on a long-term contract with NextEra. The Wheatridge wind farm is currently in the final stages of construction and will be online this year. The solar and storage resources will be constructed in 2021 and are expected to be online before the end of next year

Some Boardman employees will continue with the plant during 2021 to conduct environmental cleanup and ready the facility for demolition and removal beginning in 2022, while others will retire, move to other positions with PGE, or leave the company. The company provided a comprehensive retention and severance plan as well as education and job-training benefits to help employees fulfill their personal goals after the closure.

About Portland General Electric Company

Portland General Electric (NYSE: POR) is a fully integrated energy company based in Portland, Oregon, with operations across the state. The company serves approximately 900,000 customers with a service area population of 2 million Oregonians in 51 cities. PGE owns 16 generation plants across Oregon and other Northwestern states and maintains and operates 14 public parks and recreation areas. For over 130 years, PGE has delivered safe, affordable and reliable energy to Oregonians. Together with its customers, PGE has the No. 1 voluntary renewable energy program in the U.S. PGE and its 3,000 employees are working with customers to build a clean energy future. In 2020, PGE, employees, retirees and the PGE Foundation donated $5.6 million and

volunteered 18,200 hours with more than 400 nonprofits across Oregon. For more information visit portlandgeneral.com/news.

Safe Harbor Statement

Statements in this news release that relate to future plans, objectives, expectations, performance, events and the like may constitute "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995, Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements include statements regarding the company's future energy mix; statements concerning the company's integration of smart-grid technologies and renewable energy into the grid; statements regarding acquisition, construction, completion, and operation of generating and battery storage facilities; as well as other statements containing words such as "anticipates," "believes," "intends," "estimates," "promises," "expects," "should," "conditioned upon," "will," "would," "could" and similar expressions. Investors are cautioned that any such forward-looking statements are subject to risks and uncertainties, including construction and operational risks relating to the generation and battery storage facilities, including wind conditions and unscheduled delays or plant outages, which may result in unanticipated operating, maintenance and repair costs, as well as replacement power costs; the costs of compliance with environmental laws and regulations, including changes in weather, hydroelectric and energy markets conditions, which could affect the availability and cost of purchased power and fuel; changes in capital market conditions, which could affect the availability and cost of capital and result in delay or cancellation of capital projects; failure to complete capital projects on schedule or within budget, failure of the counterparty to perform under the agreements, or the abandonment of capital projects, which could result in the company's inability to recover project costs; the outcome of various legal and regulatory proceedings; and general economic and financial market conditions. As a result, actual results may differ materially from those projected in the forward-looking statements. All forward-looking statements included in this news release are based on information available to the company on the date hereof and such statements speak only as of the date hereof. The company assumes no obligation to update any such forward-looking statement. Prospective investors should also review the risks and uncertainties listed in the company's most recent annual report on form 10-K and the company's reports on forms 8-K and 10-Q filed with the United States Securities and Exchange Commission, including management's discussion and analysis of financial condition and results of operations and the risks described therein from time to time.

Boardman Asset Balancing Account
As of June 30, 2020

	Sch. 145 Collection-ARO*	Sch. 145 Collection-Salvage (In 108)	Sch. 145 Collection - Severence	Sch. 145 Collection - Retention**	Other - Storeroom Decommissioning	PRC ARO Funds Received	PRC Retention Funds Received	Total
Collections to Date	58,290,825	(15,030,647)	7,420,809	7,333,327	-	3,601,038	1,024,800	62,640,153
Expenses Incurred	(57,938,362)	-	-	(6,632,635)	-	-	-	(64,570,997)
Net Reg Liability (Asset)	352,463	(15,030,647)	7,420,809	700,692	-	3,601,038	1,024,800	(1,930,844)

*ARO Expenses incurred represent GAAP expenses associated with an Asset Retirment Obligation (ARO accretion and Asset Retirement Cost amortization). Actual cash settlements of the associated ARO were $3.6M as of June 30, 2020. See detail below.
**Retention Expenses represent GAAP expense accrual as of June 2020. Actual payments are $6.631M through March 2020. The remainder are accrued amounts not yet paid out.

Boardman ARO Settlements - As of June 2020.

Work Order Description	**Amount**	
Brdm Decom - Coal Storage	$ 1,541,929	Primarily Coal Reclamation costs
Boardman Decom Plan	357,993	
Brdm Decom - Brdm-Carty Separation	234,182	
Bdm Decom - Site Cert Planning	266,344	
Brdm Decom - Admin/Wrhse/Shop	4,983	
Brdm Decom - Environmental Cleanup	6,943	
Brdm Decom - ERM Abatement	105,279	
Brdm Decom - Ash Landfill	92,189	
Brdm Decom - Demolition	47,190	
Brdm Decom - Decommissioning	303,011	
Brdm Decom - Proj Management	641,168	
	$ 3,601,212	

December 16, 2021

To: Will Gehrke
Citizens Utility Board

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to CUB Data Request 059
Dated December 9, 2021

Request:

Refer to UE 394 / PGE / 2300 / Tooman – Batzler / 14 / Table 1,

a. Please provide an itemized list of investments used to create the information identified as "incremental plant related revenue requirement" in Table 1.

Response:

PGE objects to this request on the basis that it is unduly burdensome. Without waiving its objection, PGE responds as follows:

PGE's incremental plant-related revenue requirement is calculated by the following method:

2019 Lag - the difference between PGE's actual year end 2018 rate base and PGE's actual average Regulated Adjusted Rate Base as reported in PGE's 2018 and 2019 Results of Operations Reports.

2020 Lag - the difference between PGE's actual year end 2018 rate base and PGE's actual average Regulated Adjusted Rate Base as reported in PGE's 2018 and 2020 Results of Operations Reports.

2021 Lag - the difference between PGE's actual year end 2018 rate base as reported in PGE's 2018 Results of Operations Report and PGE's UE 394 rate base request plus adjustments from the UE 394 second partial stipulation.

PGE has provided numerous data responses within this docket detailing plant additions forecast to close from 12/31/2020 to April 30, 2021, including but not limited to PGE's response to OPUC Data Request No. 186, Attachment 186-A, PGE's response to OPUC Data Request No. 199, Attachment 199-A, and PGE's response to OPUC Data Request No. 256.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 394

REBUTTAL TESTIMONY OF THE

OREGON CITIZENS' UTILITY BOARD

EXHIBIT 500

I. INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is William Gehrke. I am an Economist employed by Oregon Citizens' Utility Board (CUB). My business address is 610 SW Broadway, Ste. 400 Portland, Oregon 97205.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is provided in UE 394 – Stipulating Parties/100/7.

Q. What is the purpose of your testimony?

A. I respond to issues raised by Portland General Electric in its Reply Testimony in this proceeding. In addition, I respond to several issues raised by other parties, including the Alliance of Western Energy Consumers (AWEC). Specifically, my testimony addresses:

II. Ice Storm and Wildfire Deferral Proposals;
III. Fee-free Bank Card Cost Allocation;
IV. Customer Charge – Multi-Family and Single Family Residential;
V. Residential Line Extension Policy;
VI. Habitat Restoration; and
VII. HB 2193 – Energy Storage

II. ICE STORM AND WILDFIRE DEFERRALS

Q. Please summarize your testimony on this subject.

A. CUB recommends that the Commission take not action on the Ice Storm and Wildfire deferrals in this case.

Q. Does the Company have outstanding deferrals on wildfire and ice storms?

A. Yes. The Company has filed for deferred accounting for the 2020 Oregon wildfires (Wildfire Deferral) and the 2021 ice storm restoration costs (Ice Storm Deferral).

Q. Did AWEC make a proposal on the Ice Storm and Wildfire deferrals?

A. Yes. AWEC proposed to offset the revenue associated with the Boardman Deferral with the Ice Storm and Wildfire Deferrals. AWEC argues that costs for the UM 2156 Ice Storm deferral and UM 2115 Wildfire deferrals are known and can be handled in the general rate case.[1] AWEC argues that PGE had the opportunity to amortize the balances associated with the two emergency deferrals (Ice Storm and Wildfire Deferral) and should not earn additional financing charges associated with the delay in amortization.

CUB responds to Boardman issues in CUB/400 and will address AWEC's points on the Storm/Wildfire deferrals below.

Q. What is PGE's reaction to AWEC's testimony on the Ice Storm / Wildfire deferrals?

A. PGE believes that it premature to begin amortizing the ice storm and wildfire deferrals.[2] PGE asserts that the amortization phase is not yet appropriate for both the ice storm / wildfire deferrals.

Q. What is Staff's position on the Ice Storm / Wildfire deferrals?

[1] UE 394 – AWEC/100/Mullins/46,lines 16- 17.
[2] UE 394 – PGE/2300/Tooman – Batzler /8.

A. At the time of this testimony, Staff does not have a formal position on the Ice Storm / Wildfire deferrals. However, Staff indicated that it would like for the Company to discuss options to mitigate the price impact of the deferrals on ratepayers' prices.

Q. Does PGE have a significant amount of money due to be collected from customers in differed accounts?

A. Yes. PGE expects collect millions of dollars from 2020 to 2022 from PGE's customers from the COVID-19 Emergency, 2020 Wildfires, 2021 Ice Storm, and the 2021 power costs. While a prudence review has not been conducted for these incremental costs, CUB expects that collecting these costs from customers will have a significant impact on rates, and this general rate case does not represent the full of extent of rate increases customers will incur, as several deferrals remain outstanding.

Q. How did PGE respond to Staff's testimony around price mitigation and emergency deferrals?

A. In response testimony, PGE stated that it plans on proposing a multi-year amortization schedule to reduce rate impacts associated with the deferrals.

Q. Does CUB have a recommendation to help mitigate the prices increases associated with these deferrals?

A. Yes. CUB asks PGE to support state legislation that would enable it to securitize these emergency costs. While I am not an attorney, it is my understanding that legislation would be needed authorize the securitization of outstanding costs. This would enable PGE to recover these costs over an extended period, at the interest rate of a corporate bond. It is CUB's understanding that PGE is considering proposing legislation that would enable securitization of these costs, which would be benefital to residential customers.

Q. How do interest rates work for a deferral, and what are the implications of that interest rate?

A. Deferred accounting allows the utilities to track revenues and expenses outside of those collected through base rates and amortize those costs and revenues to a later date. In the UM 1147 deferral investigation, the Commission established that prior to amortization, deferrals earn interest at the Company's most recently approved authorized rate of return. After amortization, funds in the deferral accrue at the modified blended treasury rate.

In general, PGE has used a deferral mechanism to track incremental expenses/revenues incurred outside of a general rate case. Not only does deferred accounting allow PGE to track expenses outside of a general rate case, but it also is an earnings opportunity for the Company prior to amortization. Once a deferral is amortized, it has been CUB's experience that Oregon utilities want to amortize the balance over as short a window as possible in order to maximize value for shareholders. However, CUB does want to note the Company's willingness to amortize the emergency deferrals over several years.

Q. Has PGE presented opening testimony on the Ice Storm Deferral and the Wildfire Deferral?

A. No. The Company has not made a case before the Commission that the Ice Storm Deferral and the Wildfire Deferral are appropriate for amortization in this proceeding.

Q. In Opening Testimony, AWEC-CUB proposed to amortize the Boardman Deferral. How do you think it is reasonable for AWEC-CUB to propose amortizing the Boardman deferral in Opening Testimony, while you recommend that amortization of the Ice Storm and Wildfire deferrals should occur at a later date?

A. The Boardman Deferral is an AWEC and CUB application. AWEC-CUB are the parties that bear the burden of proof that the cost is reasonable. The Commission has explicitly enabled issues related to the Boardman deferral—and other deferrals—to be addressed in this proceeding. AWEC and CUB have built an evidentiary record in this proceeding that is sufficiently robust to enable a Commission decision on the Boardman deferral. However, the Wildfire and Ice Storm deferrals have not been sufficiently addressed in this proceeding. The Wildfire and Ice Storm deferrals are Portland General Electric's application, and the Company has not put on a case on the reasonableness of the costs, nor has a prudence review occurred. Further, it may be in the public interest to wait until after the legislative session to see whether legislation is passed that may alleviate the burden of these deferrals on customers.

Q. What is CUB's recommendation?

A. CUB is recommending that the Commission not rule on the Ice Storm and Wildfire deferrals in this proceeding. It is CUB's understanding that PGE may be proposing legislation in the forthcoming short session that would enable the Company to securitize its numerous emergency deferral costs and spread the cost over an extended period (10+ years) to smooth price volatility to customers. CUB would be supportive of such legislation.[3]

CUB appreciates AWEC's proposal to amortize the Boardman deferral at the same time as the Wildfire and Ice Storm emergency deferral and understands that AWEC is trying to minimize the impact of waiting for the deferral to be amortized. However, CUB would like for customers to pay for prudently incurred costs over an extended period to mitigate price concerns. CUB asks the Commission to wait on amortizing the costs associated with the Ice Storm and Wildfire deferrals to potentially enable the costs to be spread over an extended period. Since the Ice Storm and Wildfire deferrals have their own proceedings, a prudence review and examination of potential amortization can occur in those venues.

III. FEE-FREE BANK CARD COST ALLOCATION

Q. Please summarize your testimony on this subject.

A. The Company's Direct Testimony proposed to allocate the costs of fee-free bank cards based on the number of customers enrolled in paperless billing. In April 2020, PGE began to offer fee-free bank card usage to larger customers classes. Due to this change, CUB proposed an alternative cost allocation method, which separates costs between residential and non-residential based upon ratemaking

[3] CUB is supportive of the securitization concept generally, but reserves the right to rescind its recommendation once the language of the bill is available.

principles of cost causation. In its Opening Testimony, Staff proposed to allocate fee-free bank card costs on an equal percent of revenue basis.[4] In Reply Testimony, PGE recommended that these costs be allocated based on direct cost assignment. That is, based upon cost causation principles that assign costs to customer classes to the extent costs are driven by each class. CUB is supportive of PGE's proposed cost allocation and hereby formally withdraws our initial recommendation in this case.

Q. What was the initial cost allocation proposal proposed by PGE?

A. PGE proposed to allocate fee-free bank card payments based on the number of paperless customers under 200 kW. This cost allocation method allocated 93% of the cost of the fee-free program to residential customers. As mentioned, in April 2020, PGE began to offer fee-free bank card programs to non-residential customers. Unlike residential customers, non-residential customers' bank card usage is charged based on a percentage of the bill. This means that there are significantly higher fee-free bank card costs associated with non-residential fee-free bank card usage. The Company's opening cost allocation method for fee-free bank cards was unacceptable to CUB for this reason.

Q. What is CUB's position on the Company's proposal to allocate the cost of the fee-free bank card program?

A. CUB prefers the Company's cost allocation methodology over Staff's proposal to allocate costs on an equal percent of revenue basis because it aligns with cost causation principles and directly assigns costs to each customer class. CUB also

[4] UE 394 – Staff/400/Scala/39, lines 3-4.

prefers the Company's cost allocation because it means residential customers will not be unnecessarily subsidizing the higher costs associated with the fee-free bank card program for non-residential customers.

IV. LEVEL III STORM OUTAGE RESTORATION MECHANISM

Q. Please summarize your testimony on this subject.

A. In order to better capture the dynamic nature of storms affecting the Company's system, CUB asks the Commission to make incremental changes to the Level III Storm Outage Restoration Mechanism. CUB recommends that the Commission adopt CUB's recommended changes to the Level III Outage Restoration Mechanism. That is, the account should be allowed to go negative, subject to a hard cap.[5] As an alternative, CUB does not oppose Staff's proposed changes to the Level III Outage Mechanism, with a minor change to the timing of the annual rate change.[6] CUB asks the Commission to make incremental changes to the Level III. CUB recommends that the Commission reject PGE's proposed Level III Outage Mechanism.

Q. What is the current Level III Outage Restoration Mechanism?

A. PGE has a storm reserve account that accrues funding based on the ten-year rolling average of costs of restoring its system after level III storms. The ten-year rolling average is inflated to present money with an inflation index. Annually, net annual storm savings are placed in the storm reserve account.

Q. Is this mechanism a departure from normal ratemaking?

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[5] UE 394 – CUB/200/Gehrke/19.
[6] CUB suggests moving the date of the rate change from May to January 1st of each year.

A. Yes. Normally, a specific cost for something like storm restoration is forecasted in a GRC. Forecasted costs are baked into rates and are set to include revenue sufficient to cover a prudently incurred cost. However, major storm restoration costs vary from year to year. Some years, the Company experiences no level III storm costs. In other years, the Company experiences high level III storm costs. Therefore, storm costs are forecasted based on historical averages to address annual fluctuation in costs and PGE is allowed to save storm cost funding from one year to the next to cover fluctuations in costs. By removing level III storm costs from base rates and putting them into a mechanism that includes updates from historical averages, the Company is already receiving a benefit. The mechanism should be structured in a manner that fairly shares risk between the Company and its customers.

Q. Why was this mechanism established?

A. Until 2010, Portland General Electric held insurance for physical loss and damage to transmission and distribution property.[7] After the 2008 December Oregon Storm, the Company exhausted the maximum amount of insurance recovery under its insurance policy. After using its T&D insurance in 2008, PGE was unable to economically acquire replacement insurance coverage when its insurance expired in 2010.

In response to this risk in 2010, PGE proposed a balancing account to track the difference between actual cost and amounts collected in rates. In response to

[7] UE 215 – PGE/1000/Pope -Tooman/9, lines 8-13.

PGE's proposal, Staff proposed the current storm reserve mechanism, which was accepted by PGE and parties in 2010. While CUB's witness was not a participant to the general rate case that led to the current mechanism, based on CUB's review of the record, the Level III Storm balancing account did not consider climate change's impact on storms when it was established. Instead, the mechanism was designed to allow PGE a smooth recovery of Level III outage events that impacted the Company's T&D system after losing the ability to economically purchase T&D damage insurance on behalf of customers.

Q. What is PGE's proposal for the Level III Outage Restoration Mechanism?

A. PGE has proposed to modify the current mechanism into one that allows negative balances but would be subject to some cost sharing.[8]

Q. How would you describe PGE's proposed mechanism for Level III costs?

A. PGE's proposed level III storm mechanism is too favorable for the company and is a major departure from the current level III cost recovery mechanism. PGE's proposed 90/10 (customers/shareholders) sharing is a minimal amount of sharing for shareholders. It is CUB's view that the mechanism should focus on being fair to customers while incrementally minimizing cost recovery risk moving forward.

Q. What is Staff's position on the Level III Storm Outage Restoration Mechanism?

A. Staff recommends rejecting PGE's proposal. In support of its recommendation, Staff applied a Mann-Kendall Test to determine whether PGE's experience with Level III events has a monotonic trend and was unable to reject the null

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[8] UE 394 – PGE/1400/Tooman-Batzler/39.

hypothesis that there is no trend in Level III events.[9] In summary, Staff provided that there is insufficient statistical evidence of a trend for Level III storm events. Staff recommend that PGE be allowed to update the 10-year average annually in May of each year. Staff makes this proposal to help the Company with prudently incurred cost recovery associated with Level III events.

Q. What is CUB's response to Staff's proposal?

A. In developing opening testimony, CUB considered proposing to annually update the Level III storm mechanism and thinks that this approach fairly compensates the Company while taking into account climate change's impact on the severity of storms. If the Commission accepts Staff's recommendation for annual rate changes, CUB recommends that the rate change for the rolling ten-year average of level III events occur on January 1st of each year. CUB believes the Commission to endeavor to reduce the frequency of rate changes for customers. One Oregon utility, NW Natural, conducts many of its tariff changes (commodity cost, decoupling, base rate changes) to occur on November 1st of each year. CUB thinks this makes rates easier to understand and provides price clarity to consumers of electricity and natural gas. CUB's proposal would not be burdensome on PGE; the Company already updates several supplemental schedules on January 1st of each year. Instead of changing the supplemental schedule associated Level III every May, CUB recommends that the Staff's proposal occur on January 1st of each year to minimize the frequency of rate changes.

[9] UE 394 – Staff/1400/St. Brown/7.

Q. What was PGE's reaction to Staff and CUB's proposal?

A. PGE maintained that its proposal detailed in PGE/800 is its preferred method, but noted "that CUB's proposal of a balancing account and specified hard caps coupled with Staff's proposal of annual updates represents a reasonable alternative."[10]

Q. Does CUB support combining Staff and CUB's proposal for Level III events?

A. No. Such a proposal would be too favorable to the Company. Staff and CUB determined their testimony independently. In determining CUB's position on Level III Storm costs, we considered proposing annual updates to Level III storm costs or the negative balancing account with a hard cap.

CUB preferred the hard cap approach, because cost recovery will continue to be evaluated in a general rate case proceeding. PGE has numerous cost trackers, which make it difficult to track the price impact associated with PGE's rate requests. The hard cap approach does not put the burden of auditing and micromanaging the Company's efforts to restore service on Staff and Intervenors. At this time, CUB prefers having rate changes associated with Level III outage events occurring in a general rate case, rather than occurring annually in an abbreviated proceeding with limited opportunity for review.

Q. What was CUB's rationale for imposing a hard cap on the balancing account?

[10] UE 394 – PGE/1400/Tooman-Batzler/43, lines 10-16.

A. PGE initially proposed the Level III outage mechanism due to its exhausting its insurance coverage, and the Company being unable to economically obtain T&D property insurance. The current Level III outage mechanism is a self-insurance mechanism, where ratepayers pool money each year into a reserve account, and PGE can use that fund to restore service to customers. In the current configuration, PGE's customers fund a normal level of spending annually for minor to moderate Level III storm costs. CUB's proposal to establish a hard cap based on twice the rolling average is based on the claim limits from insurance companies. When an insurer takes on risk for a third party, it is typical for the policy to include risk mitigation clauses for the insurer, such as a policy limit. I n recognition of the potential volatility of storm costs for PGE, and its effect on costs recovery, CUB proposed an incremental change to the mechanism to better enable PGE to recover costs, while sharing cost risk with customers and the Company.

Q. Do you consider PGE's proposal around Level III storm costs to be an incremental change to the risk allocation between customers and the Company?

A. No. Currently, the risk of increased Level III restoration costs between general rate cases lies with PGE, who manages its wires system and is therefore best equipped to manage this risk. PGE's proposal places a significant portion of the cost risk on the customers, and significantly limits incentive for PGE to control costs comprehensively.

Q. What is the CUB's position on the application of the Wildfire costs to the Level III outage mechanism?

A. CUB is concerned that PGE is under the impression that the Level III outage mechanism is designed to recover costs associated with wildfire restoration costs.[11] It is CUB's position that that PGE has not justified expanding this mechanism to cover wildfire costs. While PGE's service territory was subject to historic wildfires in the last two years, wildfire restoration costs were not considered by the Company when the Level III mechanism was established. Staff also questioned the applicability of the Level III storm mechanism to recover wildfire related costs.[12] Further, the Commission has adopted rules to ease the timing issues related to filing emergency deferrals. There are alternate, more appropriate venues to address the recovery of wildfire-related costs.

Q. What was PGE's response to CUB and Staff's concern?

A. PGE states that CUB and Staff's concern is made in error. PGE points to the UE 215 stipulation and claims that nothing in the stipulation or Commission Order No. 10-478 excludes Level III events caused by wildfires.[13]

Q. What is your response to PGE's testimony?

A. While CUB's witness was not a participant in UE 215, CUB finds no reference to wildfires in UE 215 when the Company proposed to move away from traditional ratemaking for Level III storm costs. Staff's proposal from opening testimony was adopted in joint stipulation in UE 215. Staff witness Dustin Ball's testimony titled

[11] *See* UE 394 – PGE/1400/Tooman-Batzler/44-45.
[12] UE 394 – Staff / 1400 / St. Brown / 5.
[13] UE 394 – PGE/1400/Tooman – Batzler/44.

the Level III mechanism as the "Proposed Storm Damage Balancing Account".[14] There is no evidence that wildfire was contemplated when this mechanism was established in 2010. The Company appears to be parsing the language in a way it was not intended, and its proposal to include wildfire-related costs in the Level III outage restoration mechanism should be denied.

V. CUSTOMER CHARGE – MULTI-FAMILY AND SINGLE FAMILY

Q. Please summarize your testimony on this subject.

A. CUB supports separate pricing for multi-family basic charge but opposes the increase of the single-family basic charge.

Q. Did PGE respond to CUB testimony on the multi-family and single-family customer charge?

A. No.

Q. Does CUB still have concerns that PGE's proposed single family charge would be the highest Investor Owned Utility customer charge in the region?

A. Yes.

Q. PGE made a claim that its last material increases to the residential basic charge was in 2001. Would you like to respond to this portion of their testimony?

[14] UE 215 – Staff/400/Ball/1 .

A. Yes. PGE implies that it has not had a basic charge increase since 2001. However, this is not the case. In UE 297, the residential customer charge was increased.[15] In UE 319, the residential customer charge was increased.[16]

Q. Did PGE make a statement around how the basic charge will affect low-income residential customers?

A. Yes. PGE stated that it plans on proposing a low-income rebate program before the effective date of this general rate case, and that the rebate is expected to cover any increase to the basic charge for single family residential customers.[17]

Q. What is CUB's response to PGE's statement?

A. While CUB is supportive of interim rates for low-income customers to address energy burden for residential customers, CUB is concerned that it will take time for customers to sign up for low-income discounts and it may not reach all low-income customers when rates are changed later this year.

Q. Does CUB have a response to Staff's testimony?

A. Yes. CUB is willing to explore minimum bills in an upcoming general rate case and appreciates Staff's creative recommendation. However, CUB would like to be clear that it would like to see grandfathering in effect for incumbent net metering or community solar customers if minimum bills are going to be considered. PGE's customers have invested significant amount of capital in order to generate electricity at their home. A minimum bill proposal could lengthen the payback period associated with these contracts or capital investments.

[15] OPUC Order No. 15-356.
[16] OPUC Order No. 17-511.
[17] UE 394 – PGE/2200/Macfarlane – Tang/16, lines 7-9.

VI. RESIDENTIAL LINE EXTENSION

Q. Please summarize your testimony on this subject.

A. CUB supports Staff's position to reject PGE's proposed residential line extension allowance (RLEA). CUB agrees with Staff's position that the Company's residential line allowance was recently reviewed by parties and should not be updated at this time. Instead of requiring PGE to update the RLEA in 2024, CUB recommends that the Commission order PGE to keep its RLEA in place until its next general rate case, where the Company can propose changes to the RLEA.

Q. Why does CUB recommend reject the proposed residential line extension allowance?

A. PGE recently got approval for a new line extension policy for residential customers outside of a general rate case. PGE's proposed line extension policy was the first in the country to differentiate between all-electric homes and non-electric homes when establishing the line extension amounts. Broadly, CUB was supportive of the revised LEA. But, this was a significant policy proceeding for residential customers in Oregon.

Q. What was CUB's recollection of the residential line extension proceeding?

A. CUB recalls that there was concern over data used to estimated forecasted revenue from all electric customers and non-electric customers. PGE's current RLEA amounts were established based on a compromise between Staff and PGE. There has been limited experience with the new RLEA, and CUB prefers to keep the RLEA in place to be conservative with the allowance, and to match the spirit of the agreement around the bifurcated RLEA. CUB recommends that the

Commission order PGE to retain the incumbent RLEA amount and allow PGE to update its RLEA in its next rate case.

VI. HABITAT RESTORATION

Q. Please summarize your testimony on this subject.

A. Residential and Small Commercial customers are allowed to participate in the Green Future Portfolio program, which enables these customers to purchase renewable portfolio certificates. Customers who subscribe to the Green Future Portfolio program have the option to pay a surcharge to support habitat restoration. In order to support additional options for residential and small commercial customers, CUB recommends that Schedule 7 and 32 customers should be allowed to subscribe to habitat restoration without being enrolled in green future portfolio program.

Q. Did PGE respond to CUB's testimony on Habitat Restoration?

A. Yes. PGE stated that the issue should be addressed in Docket No. UM 1020 and that its is inappropriately being addressed in the general rate case.

Q. What is CUB's response to PGE's testimony?

A. PGE raises no substantive arguments with CUB's proposal. This is an appropriate proceeding to evaluate this issue. In April 2021, in preparation for this general rate case, CUB informally asked the Oregon Department of Justice on the appropriate venue to raise this tariff change. The Oregon Department of Justice advised CUB that the portfolio option committee (which reviews PGE's green future portfolio program) has been suspended, and that a general rate case could be an appropriate venue to make CUB's proposal. All types of tariff and pricing changes are regularly reviewed in a general rate case, and the Company has made no compelling argument regarding why this should not be addressed here. Further, CUB's proposal would provide PGE customers with additional options, in the spirit of portfolio options requirements.

VII. HB 2193 – SCHEDULE 138 – ENERGY STORAGE

Q. Please summarize your testimony on this subject.

A. The Company's proposed Schedule 138 language enables the Company to recover "expenses associated with energy storage pilots not otherwise included in rates."[18] Because of this language is too broad, CUB proposes to the change the language to "expenses associated with HB 2193 energy storage pilots." In UE 370, AWEC, CUB, Staff, and Portland General Electric agreed to allow PGE to seek cost recovery for battery storage cost associated with HB 2193. PGE's proposed language is too broad and should be refined to comply with the UE 370 stipulation.

Q. Is CUB still seeking its alternative tariff language be reflected in Schedule 138?

A. Yes.[19]

Q. Does this conclude your testimony?

A. Yes.

[18] UE 394 – PGE/1204/Macfarlane – Tang/74.
[19] CUB Exhibit 200.