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August 22, 2023

Via Electronic Filing

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

Re: In the Matter of PORTLAND GENERAL ELECTRIC CO.
Request for a General Rate Revision.
Docket No. UE 416

Dear Filing Center:

Please find enclosed the redacted version of the General Rate Case ("GRC") Rebuttal Testimony of Bradley G. Mullins (AWEC/600) and Lance D. Kaufman (AWEC/700-701) on behalf of the Alliance of Western Energy Consumers ("AWEC") in the above-referenced docket.

Please note that AWEC's GRC Rebuttal Testimony contains Protected Information Subject to Modified General Protective Order No. 23-039. The confidential portions of AWEC's filing have been encrypted with 7-zip software and are being transmitted electronically to the Commission and qualified persons.

Thank you for your assistance. If you have any questions, please do not hesitate to call.

Sincerely,

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

Enclosures

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the **Confidential GRC Rebuttal Testimony of the Alliance of Western Energy Consumers** upon the parties shown below via electronic mail.

Dated at Portland, Oregon, this 22nd day of August, 2023.

Sincerely,

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 416

In the Matter of	)
	)
Portland General Electric Company,	)
	)
Request For a General Rate Revision.	)
	)

REBUTTAL GENERAL RATE CASE TESTIMONY

OF

BRADLEY G. MULLINS

ON BEHALF OF

THE ALLIANCE OF WESTERN ENERGY CONSUMERS

(REDACTED)

August 22, 2023

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I. INTRODUCTION AND SUMMARY

Q. ARE YOU THE SAME WITNESS THAT FILED DIRECT TESTIMONY IN THIS MATTER?

A. Yes. I previously filed Opening Net Variable Power Cost ("NVPC") testimony in Exhibit AWEC/100, as well as Opening General Rate Case ("GRC") testimony in Exhibit AWEC/200 and Rebuttal NVPC Testimony in Exhibit AWEC/400, all of which were submitted on behalf of the Alliance of Western Energy Consumers ("AWEC").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I respond to the GRC Reply Testimony of Portland General Electric Company ("PGE") witnesses Bekkedahl-Putnam regarding distribution forestry expenses; Loos-Cristea regarding generation operations and maintenance ("O&M") expenses; Batzler-Agnesse regarding insurance expenses; Baltzer – Ferchland regarding state income taxes and working capital; and Sims-Outama regarding proposed changes to the Power Cost Adjustment Mechanism ("PCAM").

Q. HAVE THE PARTIES REACHED A SETTLEMENT ON ANY OF THE ISSUES YOU RAISED IN OPENING GRC TESTIMONY?

A. Yes. Since filing Opening GRC Testimony, parties have convened several settlement conferences. In those settlement conferences, an agreement in principle has been reached on several issues, including a number of issues I raised in my Opening GRC Testimony. Accordingly, I have not discussed those issues in this Rebuttal GRC Testimony

Q. PLEASE SUMMARIZE YOUR REBUTTAL GRC TESTIMONY.

A. My recommendations on outstanding revenue requirement issues are detailed below.

1. *Average Rate Base:* I support Staff's recommendation to calculate revenue requirement using an average rate base because it results in a more consistent revenue

requirement calculation than the method PGE used. Notwithstanding, to fully be consistent, I recommend that year-end 2023 depreciation expenses be used, which in addition to Staff's rate base adjustment, reduces operating expenses by $11,632,259.

2. *Distribution Forestry Expenses:* I recommend the Commission reject PGE's budgeted 90% increase to distribution forestry expenses, and at a maximum, limit PGE's budget to two times the annual rate of inflation, an approach that otherwise results in a $20,636,497 reduction to PGE's budgeted operating expenses.

3. *Generation Outside Service:* I continue recommending an adjustment for generation outside services, limiting the increase, at a maximum, to annual inflation rates, which produces a $2,255,670 reduction to PGE's budgeted operating expenses.

4. *Property Insurance Expense:* I recommend property insurance expenses be set at the effective premiums for the period July 2023 through June 2024. This change results in a $1,788,313 reduction to PGE's budgeted operating expenses. Given the nature of these expenses, which cover acts of negligence, it is reasonable to subject them to modest regulatory lag.

5. *Wind Outside Services:* I accept PGE's explanation related to wind outside services.

6. *State Income Tax Flow-Through Method:* I believe that using the flow-through method for state taxes is consistent with good regulatory policy, and continue to recommend an adjustment to transition to that method.

7. *Working Capital:* I accept PGE's explanation with respect to working capital, though I continue to have concerns with the way that the working cash factor is calculated.

8. *PCAM Changes:* I continue to recommend that the existing design elements of the PCAM be retained. The PCAM has been the subject of over a decade of litigation, in which it has been repeatedly reaffirmed by the Commission, and PGE offers no valid reason to depart from past precedent.

II. AVERAGE RATE BASE

Q. WHAT DID STAFF RECOMMEND WITH RESPECT TO AVERAGE RATE BASE?

A. In Exhibit Staff/800, Staff witnesses Stevens and Young "recommend the Commission reject the pre-test period snapshot (PTPSS) method used by PGE to calculate rate base for purposes of establishing the return component of PGE's revenue requirement." Instead, Staff recommended the Commission adopt an average rate base value, which considered incremental accumulated depreciation in the year ending December 31, 2024 (the "Test Period").

Q. DOES AWEC SUPPORT STAFF'S RECOMMENDATION?

A. Yes. Use of an average rate base values better aligns with expenses and revenues, which occur ratably over the course of the Test Period.

Q. HOW DID PGE RESPOND?

A. PGE states that its calculation of rate base using the PTPSS method is reasonable because it is consistent with past practice.[1]

Q. DO YOU AGREE?

A. No. Just because a method is consistent with past practice does not mean that its continued use is reasonable.

Q. DOES THE PTPSS METHOD RESULT IN INCONSISTENCIES IN REVENUE REQUIREMENT?

A. Yes. For example, PGE's revenue requirement uses expenses that are escalated at high rates into the 2024 Test Period. Notwithstanding, the corresponding benefit of incremental accumulated depreciation that will accrue over the same time period is not being considered in PGE's revenue requirement. The accumulated depreciation would otherwise offset the impact of these escalating expense levels. Therefore, PGE's approach results in an inconsistent revenue requirement because it is capturing escalated expenses but not the corresponding accumulated depreciation in the Test Period.

1 PGE/1700, Batzler – Ferchland /13:1-16:16.

Q. ARE DEPRECIATION EXPENSES IN PGE'S REVENUE REQUIREMENT CONSISTENT WITH RATE BASE?

A. No. Under PGE's PTPSS method, depreciation expenses are effectively calculated on a forward-looking basis over calendar year 2024. Notwithstanding, the incremental accumulated depreciation reserves associated with those depreciation expenses over the same period are not being considered in revenue requirement. Under PGE's approach, ratepayers would be paying for depreciation expenses in calendar year 2024, but not getting the associated benefit of those depreciation expenses through an increase in accumulated depreciation. This approach is both inconsistent and unfair to ratepayers.

Q. HOW DOES PGE CALCULATE TEST PERIOD DEPRECIATION EXPENSES?

A. The workpapers that calculated depreciation expenses were provided in response to AWEC Data Request 39. In the response, PGE labeled the depreciation expenses as 2023 values. Notwithstanding, PGE added in the plant additions through the end of 2023 assuming they were in service on January 1, 2023, even though the plant was placed in service at various times throughout 2023. This was done with the apparent objective of calculating a forward looking, 2024 depreciation expense.

Q. IS PGE'S APPROACH REASONABLE?

A. No. PGE's approach is a mismatch of 2024 and 2023 depreciation expenses, which, due to the unique way PGE calculates depreciation expenses, results in an unreasonable level of depreciation expenses relative to the plant balances included in rate base. PGE calculates depreciation expense in a manner different from other utilities, based on net plant balances, in contrast to gross plant balances. By adding in the 2023 plant additions at the beginning of 2023, however, PGE introduced a gross inconsistency between the depreciation expense calculations and the plant balances used for rate base. Because net plant balances decline as depreciation accrues, PGE's depreciation expenses calculated based on those net plant balances also decline over the measurement period. PGE, however, did not consider that reduction in depreciation expense in its revenue requirement calculation.

Q. HOW SIGNIFICANT ARE THE DECLINING DEPRECIATION EXPENSES?

A. The December 2023 depreciation and amortization expense that PGE calculated in its depreciation model was $38,091,645.[2] This value contrasts average depreciation expenses of $39,061,000 per month over the 12-month period ending December 2023. Thus, PGE's rate base, which establishes plant based on end of period 2023 levels, is inconsistent because it does not consider the impact of declining net plant balances on deprecation expenses that will otherwise decline over 2023. Based on the difference between the monthly average, and the December 2023 depreciation expense level, PGE effectively overstated year-end depreciation expense by $969,355 per month, or $11,632,259 over the 2024 Test Period.

Q. ARE YOU RECOMMENDING A DEPRECIATION EXPENSE ADJUSTMENT IN CONJUNCTION WITH STAFF'S AVERAGE RATE BASE ADJUSTMENT?

A. Yes. If the Commission accepts Staff's adjustment to accumulated depreciation, it is also necessary to consider the unique way that PGE calculates depreciation expenses and adjust for the annualized, Test Period depreciation expenses, rather than the 2023 average. As noted, this results in a further $11,632,259 reduction to PGE operating expenses.

Q. DOES STAFF'S APPROACH VIOLATE NORMALIZATION REQUIREMENTS?

A. No. To be clear, if the Commission accepts Staff's recommendation, it will be necessary to update accumulated deferred income taxes to be based on the same period as accumulated

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[2] *See* PGE's response to AWEC Data Request 39, Attachment A Tab "Depr Query - GRC Depr."

depreciation. This is a calculation PGE would otherwise have to perform with its tax software, which the Commission would need to require of PGE as a condition in its final order. Parties have no way to perform this calculation in an accurate manner absent having access to PGE's tax software. Notwithstanding, assuming the Commission were to condition its acceptance of Staff's recommendation on PGE recalculating the 2024 accumulated deferred income taxes associated with the 2024 depreciation expense, there would be no risk of a consistency violation under the IRS normalization rules. This step could also occur in a bench request. If this were done, the net plant balances, depreciation expenses, and accumulated deferred income taxes would all be based on the same average of averages value for 2024. On the contrary, PGE's method, which uses December 31, 2023 accumulated depreciation and depreciation expenses which are a mishmash of 2023 and 2024 levels, would likely be viewed as less consistent by the IRS.

Q. WHAT DO YOU RECOMMEND?

A. I recommend the Commission adopt Staff's recommendation, subject to PGE recalculating accumulated deferred income taxes based on the accumulated depreciation reflected in the final revenue requirement. In conjunction with Staff's recommendation, I also recommend a further $11,632,259 reduction to PGE's depreciation expenses to reflect Test Period levels.

III. OPERATING EXPENSES

a. <u>Distribution Forestry Expense</u>

Q. WHAT DID YOU RECOMMEND WITH RESPECT TO FORESTRY EXPENSES IN DIRECT TESTIMONY?

A. I noted that in FERC Account 593, PGE included budgeted outside services expenses of $53,096,279 in department "341: Forestry," which consists generally of routine vegetation management expenses.[3] This value compared to $27,886,411 of actual forestry expenses incurred in 2022.[4] Thus, PGE is requesting a $25,209,867, or 90%, increase to forestry expenses in this docket.[5] Lacking a compelling justification for the increase, I recommended in Opening Testimony setting revenue requirement based on the known and measurable distribution forestry expense from 2022 of $27,886,411.

Q. HOW DID PGE RESPOND?

A. PGE responds by stating that "[w]e wrote lengthy testimony on the cost drivers and support of the 2024 test year increase to the RVM budget in PGE Exhibit 700 and responded to numerous data requests, including providing the workpaper used to develop the 2024 RVM budget."[6]

Q. DID THIS INFORMATION JUSTIFY A 90% INCREASE TO 2022 ACTUAL SPENDING?

A. No. In Direct Testimony, PGE stated that the large increase was "driven primarily by increased cost of outside services (e.g., tree trimming services)."[7] PGE stated, for example, that [redacted][8] While these statements may be sufficient to justify some budgetary increase relative to 2022 levels, if appropriately quantified, they are not sufficient to justify nearly doubling distribution forestry expense.

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3 AWEC/200, Mullins/13:11-13.
4 *Id.* at 13:14-17
5 Ibid.
6 PGE/2200, Bekkedahl-Putnam/21:18-22:2.
7 PGE/700, Bekkedahl-Jenkins/11:1-3.
8 PGE/700, Bekkedahl-Jenkins/13:2-4.

Q. DID YOU FURTHER REVIEW THE WORKPAPERS PGE PROVIDED TO STAFF?

A. Yes. The values in workpapers PGE did provide match the actual distribution forestry expense included in revenue requirement and were based on a number of unsupported assumptions. PGE, for example, calculated a 2023 routine vegetation management expense of $[redacted], even though its budgeted expenditures for 2023 were $[redacted] PGE calculated this value by adding approximately $[redacted] to the 2023 budget for "specialized crews", including a note stating "[redacted]"[9] To the extent this was true, the specialized crews would have already been considered in the budget for 2023, and were therefore unnecessary to add to the total in the manner calculated by PGE. Further, PGE's formula was mathematically incorrect because it applied the stated percentage to the total expense, rather than as a component part of the total expense. After recalculating the heightened 2023 value, PGE then further escalated its calculation by [redacted]% to arrive at an expense level of $[redacted] for the test period. No mathematical support was provided for this assumed escalation rate. Following that calculation PGE added on an additional $[redacted] for "[redacted]."[10] From this PGE calculated a total budget of $[redacted], which still does not add up to the $53,096,279 that PGE included in its filing. These significant layering on of incremental costs do not have basis in the actual costs that PGE incurred in 2022 or 2023, and therefore, are not a reasonable estimate of 2024 expenses.

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9 *See* PGE's Response to Staff Data Request 496, Attachment A.

10 *Id.*

Q. DOES PGE HAVE AN INCENTIVE TO OVERSTATE ITS ROUTINE VEGETATION MANAGEMENT EXPENSES?

A. Yes. PGE has a balancing account for its wildfire mitigation expenses. PGE has no incentive to over-estimate costs for wildfire mitigation. In contrast, there is no balancing account for routine vegetation management expenses. Accordingly, PGE has an incentive to over-estimate baseline vegetation management costs, and even to push some wildfire management costs into the routine vegetation management budget, because it will not have to return this money to ratepayers if it underspends.

Q. WHAT DO YOU RECOMMEND?

A. I continue to have concerns with the magnitude of the increase being proposed for distribution forestry expenses. To the extent that unusual inflationary factors are driving up the cost of this expense, I recommend that PGE be provided an inflationary allowance of no more than 2 times the annual inflation rate. The Core CPE for June 2023 was 4.1 %.[11] Therefore, this approach would limit the increase to distribution forestry expense to 8.2% per year, or 16.4% over two years. Such an approach would yield an inflationary allowance of $4,573,371 or a total distribution forestry expense of $32,459,782.

Q. HOW DOES THAT AMOUNT COMPARE TO THE AMOUNT PGE PROPOSES?

A. Relative to the $53,096,279 of distribution forestry expenses that PGE included in its filing, escalation of double the inflation rate would still produce a $20,636,497 reduction to operating expenses. Even inflationary allowance rates as high as four or five times the average would still result in distribution forestry levels that are materially below what PGE proposed.

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[11] *See* https://www.bea.gov/data/personal-consumption-expenditures-price-index-excluding-food-and-energy

Therefore, I continue to support a downward adjustment to PGE's distribution forestry expense.

b. <u>Generation Outside Services</u>

Q. WHAT WAS YOUR RECOMMENDATION RELATED TO GENERATION OUTSIDE SERVICES?

A. I recommended using 2022 actuals as the basis for generation outside services expenses included in revenue requirement. This resulted in an approximate $2,674,806 reduction to operating expenses. I noted that, in 2022, PGE spent $5,111,417 in 2022 on generation outside services.[12] In contrast, PGE was requesting $7,786,223 in generation outside services in the Test Period.[13] This represented a 52% increase in generation outside services, which was not justified based on the explanations PGE offered in Direct Testimony or discovery.

Q. HOW DID PGE RESPOND?

A. PGE disagreed with my recommendation, stating, "it is not reasonable to simply assume that the budget for 2022 will suffice for 2024."[14] PGE also states that its gas plants are running more, and therefore need more maintenance.

Q. DO YOU CONTINUE TO RECOMMEND A REDUCTION TO REVENUE REQUIREMENT FOR GENERATION OUTSIDE SERVICES EXPENSES?

A. Yes. Gas plants were operating at high capacity factors in 2022; therefore, PGE's expectations that the plants will run more is not a valid reason for the increase. Maintenance expenses associated with the operating frequency of a gas plant are also typically covered under the long-term service agreements, and are not necessarily a driver of the routine maintenance

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12 AWEC/200, Mullins/18, Table 5.
13 Ibid.
14 PGE/2000, Loos-Cristea/11:4-5.

expenses identified in my Opening Testimony. Further, it is common ratemaking practice to rely on actual cost data for the purposes of setting revenue requirement since the actual cost is known, whereas a budget is not. While PGE states that it is unreasonable to assume that it will incur similar costs in 2024 that it incurred in 2022, this is effectively shifting the burden to demonstrate the reasonableness of these costs to AWEC since PGE's only evidence supporting its requested increase is its budget, which is supported by nothing other than an escalation of previous budgets. In the absence of actual evidence demonstrating an increase in Generation Outside Services costs, using the 2022 actual expense as the Test Period expense level is a reasonable and acceptable approach.

Q. IS A 52% INCREASE TO THESE EXPENSES REASONABLE?

A. No. Even considering high levels of expected inflation, such a major increase to Generation Outside Service expense is not reasonable. If two years of inflation were applied at the 4.1% core CPE rate identified above, for example, it would result in a budget of just $5,530,553. Therefore, if the Commission is to apply any escalation to the Generation Outside Services account, I recommend it be limited to that level, which would still produce a $2,255,670 reduction to operating expenses.

c. <u>Property Insurance</u>

Q. WHAT WAS YOUR RECOMMENDATION RELATED TO PROPERTY INSURANCE EXPENSES?

A. I recommended that property insurance expense be set at the known and measurable levels based on PGE's most recent insurance premiums.

Q. HOW DID PGE RESPOND?

A. PGE stated that I used the 2022 premiums, not the 2023 premiums, and that therefore my analysis was inaccurate.[15]

Q. DID YOU USE THE CURRENTLY EFFECTIVE PREMIUMS?

A. That was my understanding. In AWEC Data Request 131, PGE was requested to provide the "details of the currently effective premiums, the policy coverages, policy limits, policy deductibles, and any other relevant information necessary to demine the base period expense levels." In response, PGE referred to OPUC Data Request No. 69, which is what I had used to perform my analysis. To the extent the data I used was not the currently effective data, it was due to PGE's failure to respond accurately to the data request.

Q. GIVEN PGE'S RESPONSE, WHAT IS YOUR RECOMMENDATION?

A. Because of uncertainty with the policy premiums and the nature of these costs, I continue to recommend that the currently effective policy premiums be included in revenue requirement. Given PGE's response, however, it is reasonable to use the premiums for the 2023 insurance year instead of the premiums that were in effect for the 2022 insurance year.

Q. WHAT PERIOD DO THE INSURANCE POLICIES COVER?

A. Historically, PGE's insurance policies have not been based on a calendar year, but have corresponded to the [redacted][16] This results in a mismatch between the Test Period and the insurance year since the 2023 policies will cover the period [redacted]. Thus, using the known 2023 policies encompasses [redacted] of the 2024 test period. PGE's method, on the other hand, overstates the cost of property insurance since the

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15 PGE/1900, Batzler-Agnesse/4:1-7.

16 *See, e.g.,* PGE's Response to Staff Data Request 069_Attach H_CONF, 2022 "[redacted]."

2024 policy rate increases it has included in revenue requirement for the 2024 insurance year would only apply to part of the Test Period.

Q. IS IT REASONABLE TO USE THE 2023 INSURANCE YEAR POLICY PREMIUMS IN THIS CASE?

A. Yes. Foremost, property insurance is a complicated issue, particularly in the current environment. Much of the policy cost is being driven by increased wildfire risks, and in particular events of utility negligence which have resulted in large legal settlements. Since these insurance policies cover acts of utility negligence, it is appropriate for the utility to bear a modest amount of regulatory lag with respect to its future policies. The policies, and the increasing premiums that might occur in a renewal, benefit shareholders as much as they do ratepayers.

Q. WHAT IS THE IMPACT IF YOU USE THE 2023 PREMIUM LEVELS?

A. Based on my review of PGE's response to AWEC Data Request 132, Confidential Attachment A, I was able to calculate that reverting to the 2023 policy levels would result in an approximate [redacted]3 reduction to operating expenses.

d. <u>Wind Outside Services</u>

Q. WHAT WAS YOUR RECOMMENDATION RELATED TO WIND OUTSIDE SERVICES?

A. In Opening Testimony, I recommended an adjustment to Non-Labor wind O&M of $3,063,931.

Q. HOW DID PGE RESPOND TO YOUR RECOMMENDATION?

A. PGE noted that it recorded wind O&M expenses to multiple accounts in the historical period, and that when both accounts are considered, its forecast is more in line with historical actual expense levels.

Q. DO YOU ACCEPT THIS RESPONSE?

A. Yes. Since the expenses were recorded in multiple accounts and the forecast expense aligns generally with the actual expense, I accept PGE's explanation and am withdrawing this recommendation.

IV. STATE INCOME TAX FLOW-THROUGH

Q. WHAT DID YOU RECOMMEND FOR STATE INCOME TAXES IN OPENING TESTIMONY?

A. In my Opening Testimony, I demonstrated that the IRS normalization requirements do not apply to state taxes and that it would be beneficial to ratepayers to transition to a flow-through method of accounting for state taxes in this docket.[17] Such an approach is widely used in the West. States such as California, Idaho, and Montana exclusively use a flow-through method for state taxes, and other many other states, including Utah and Oregon, use a flow-through method of accounting for some but not all jurisdictional utilities. The flow-through method is the most accurate way to set a revenue requirement because it is based on the current taxes, i.e., the actual taxes payable. The flow-through method also promotes inter-generational equity because it offsets slightly more of the cost of a new resource addition in the early years of the resource's life, which tend to be the most expensive. Therefore, I continue recommend that the flow-through method for state taxes be adopted in this docket as consistent with sound regulatory policy.

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[17] AWEC/200, Mullins/3:3-12.

Q. HOW DID PGE RESPOND?

A. PGE Witnesses Batzler and Ferchland summarize their opposition to my recommendation by stating that "AWEC's proposal is inequitable, unbalanced, opportunistic, and would result in an immediate and detrimental impact to PGE's cash flow potentially resulting in numerous other impacts, such as a material change to PGE's stock price, reduced liquidity, increased debt, and higher borrowing costs."[18]

Q. DO YOU AGREE WITH THAT STATEMENT?

A. No. To the contrary, the flow-through method captures <u>only</u> the cash flow impacts of state taxes, since it calculates state tax expense based on the actual taxes payable. In fact, PGE's statement regarding the detrimental cashflow impacts to shareholders is telling as to why it is a good policy for state income taxes to follow the flow-through method. PGE acknowledges that such a change will, from the perspective of its stockholders, produce a negative cash flow impact. Transitioning to a flow-through method, however, establishes revenue requirement based on actual cash flows associated with state income taxes. To the extent shareholders view transitioning to the actual cashflows as producing a negative impact, it means that shareholders are receiving an unjustified cashflow benefit through the application of normalization requirements. Therefore, in making that statement, PGE is effectively acknowledging that the normalization method provides a cashflow windfall to shareholders. This is an inequity that, in my view, is important to eliminate.

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[18] PGE/1700, Batzler–Ferchland/4:9-12

Q. IS THE FERC PRECEDENT ON THIS MATTER COMPELLING?

A. No. The precedent at FERC is not relevant because FERC is concerned primarily with setting wholesale transmission rates under utilities' open access transmission tariffs, not setting retail rates. Individual state public utility commissions and the FERC frequently adopt different assumptions for purposes of setting revenue requirement. Approved return on equities at the FERC, for example, are often several basis points higher than those approved by state regulators. Contrary to the email survey conducted by the Edison Institute, most states in the Intermountain West with an income tax use flow-through assumptions for state taxes for some or all their jurisdictional utilities, including Oregon. The more reasonable policy consideration from Oregon's perspective is whether it is reasonable to set state tax expenses in revenue requirement on the actual taxes payable or the theoretical tax expense calculated using the normalization method. Either approach is acceptable, although I continue to recommend using the flow-through method as the more reasonable approach.

Q. DOES THE FLOW-THROUGH METHOD RESULT IN INTERGENERATIONAL INEQUITY?

A. No. The revenue requirement of a new utility plant addition is usually highest in the first years of service and declines over time. This aspect of revenue requirement itself, presents generational inequity because the ratepayers who happen to be taking service from the utility plant when it is first placed into service will pay higher rates than ratepayers that take service later in the resource's life. By using the flow-through method, more tax benefits are recognized in the early years of a resource's life, offsetting some of the higher revenue requirement in those years. This results in a somewhat more level revenue requirement profile for the investment, promoting intergenerational equity, although the overall impacts on revenue requirement are marginal.

Q. DOES THE FLOW-THROUGH METHOD RESULT IN LARGE SWINGS YEAR TO YEAR?

A. No. Regardless of whether the normalization method or flow-through method is used, operating expenses will continue to be based on normalized assumptions. While it is true that PGE's actual tax expenses may vary year to year depending on its operating income, from a revenue requirement perspective, the year-to-year impacts are not so significant.

Q. CONSIDERING THIS INFORMATION, WHAT DO YOU RECOMMEND?

A. The flow-through method for state taxes is consistent with good regulatory policy and I continue to recommend it be adopted in this case.

V. WORKING CAPITAL

Q. WHAT DID YOU RECOMMEND WITH RESPECT TO WORKING CAPITAL?

A. I recommended that the working capital lead-lag percentage not be applied to depreciation expenses, because depreciation expenses were not included in the calculation and PGE does not incur any working capital requirements with respect to depreciation expenses.

Q. HOW DID PGE RESPOND?

A. PGE responded that including the depreciation expenses in the lead lag factor is consistent with past practice.[19] PGE also responded that "investors are not fully compensated for their expenditures until customers pay for the depreciation and amortization expense through their bills."[20]

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19 PGE/1700, Baltzer – Ferchland /70:17-71:4.

20 PGE/1700, Baltzer – Ferchland /70:21-23.

Q. DO YOU AGREE?

A. No. Depreciation expenses are not considered in the lead lag study. If they were, they would be included as an expense with no net lead or lag. Based on the way the lead lag factor is applied, however, including depreciation expenses would otherwise increase the factor because it would reduce the net lag days for operating expense. Therefore, I accept PGE's explanation and withdraw this recommendation.

VI. POWER COST ADJUSTMENT MECHANISM

q. HOW DID PARTIES RESPOND TO PGE'S RECOMMENDATIONS TO MODIFY THE PCAM?

A. Intervening parties uniformly opposed making changes to the design elements of the PCAM as PGE proposed in Direct Testimony. Staff, for example states that PGE's "proposed changes to the PCAM are entirely out of step with current principles governing the PCAM."[21] Similarly, CUB laid out the extensive history behind the current PCAM design elements and noted that "[d]espite PGE's arguments to the contrary, there is no evidence that there is a problem with PGE's PCAM, and it has been operating as the Commission intended since its inception."[22] Likewise, in my Opening Testimony, I recommended the Commission reject PGE's proposed modifications to the PCAM principles and the fundamental structure of the mechanism. Specifically, I noted that the PCAM is operating as the Commission intended and that eliminating the ratepayer protections included within the current PCAM structure was not in the public interest.[23] Moreover, I recounted the Commission's repeated rejections of efforts by

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21 Staff/2300, Ahmed–Dlouhy–Jent–Pileggi/10:11-12.
22 CUB/200, Jenks/7.
23 *See* AWEC Exhibit 200, pp. 24-25.

PGE and other Oregon utilities to modify the PCAM framework and dilute the Commission-approved ratepayer protections in favor of increased shareholder protection.[24]

Q. HOW DID PGE RESPOND TO THIS UNIFORM OPPOSITION?

A. PGE asserted that AWEC's and other intervenor parties' support for the current PCAM structure and principles did "not hold up to scrutiny" and is "antithetical to [PGE's] current and future operating environment…."[25]

Q. DO YOU AGREE WITH THE COMPANY'S CRITIQUES?

A. No. PGE has not presented anything novel in its Reply Testimony; rather, PGE has merely repeated its complaints presented in Opening Testimony. For example, with respect to the PCAM's deadbands that the Company proposes to eliminate, PGE admits that "[t]he deadband was designed to account for the normal business risk which PGE is expected to absorb as part of its return on equity"[26], but merely asserts that because utilities in its "peer group"[27] operate under a different structure, the PCAM imposes risks that are not normal.[28] However, PGE's assertion fails to capture the breadth and scope of the Commission's rationale in establishing the deadband element of the PCAM. When the Commission established the PCAM, it specifically noted that the deadband was set "so that PGE will absorb some normal variation of power costs" and that "an asymmetric deadband is necessary to ensure that the PCAM is revenue neutral."[29] PGE has not provided evidence to demonstrate that the proposed

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24 *See* AWEC Exhibit 200, pp. 29-31.
25 PGE Exhibit 2800, pp, 1-2.
26 PGE Exhibit 2800, p. 9, ll. 7-8.
27 PGE Exhibit 2800, p. 9, l. 8.
28 *See* PGE Exhibit 2800, pp. 8-9.
29 Order 07-015.

elimination of the deadband will continue to accomplish the Commission's goal of revenue neutrality.

Likewise, in Reply Testimony, PGE continued to assert that the business environment today is "profound[ly]" different than that which existed at the time the PCAM was initially approved. However, PGE did not respond substantively to my discussion in Opening Testimony where I detailed that "the current PCAM structure is operating as intended", nor where I specially discussed that "[t]he Commission has stated that 'any adjustment under a PCAM should be limited to unusual events and capture power cost variances that exceed those considered normal business risk for the utility…'"[30]

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE PROPOSED CHANGES TO THE PCAM?

A. I maintain my recommendation that the Commission deny PGE's proposal to modify the PCAM Principles and the PCAM framework structure. PGE has not provided compelling evidence that the PCAM as repeatedly reaffirmed by the Commission is not reasonable. Specifically, PGE has failed to demonstrate that any proposed changes to the PCAM will maintain the integrity of the mechanism, including, but not limited to, the revenue neutrality. I continue to recommend the Commission maintain the PCAM as currently designed and reject PGE's requests to modify it.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

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[30] AWEC/200, p. 28, ll. 10-13.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 416

In the Matter of	)
	)
Portland General Electric Company,	)
	)
Request For a General Rate Revision.	)
	)

REBUTTAL GENERAL RATE CASE TESTIMONY

OF

LANCE D. KAUFMAN

ON BEHALF OF

THE ALLIANCE OF WESTERN ENERGY CONSUMERS

(REDACTED)

August 22, 2023

TABLE OF CONTENTS

EXHIBIT LIST

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Lance D. Kaufman. I am a consultant representing utility customers before state public utility commissions in the Northwest and Intermountain West. My witness qualification statement can be found at Exhibit AWEC/301.

Q. PLEASE IDENTIFY THE PARTY ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am testifying on behalf of the Alliance of Western Energy Consumers ("AWEC"). AWEC is a non-profit trade association whose members are large energy users in the Western United States, including customers receiving electric services from Portland General Electric ("PGE").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. In this testimony I respond to rate spread, rate design, low income, and rent issues raised by other parties.

II. GENERATION MARGINAL COST

Q. PLEASE SUMMARIZE YOUR OPENING TESTIMONY RECOMMENDATIONS REGARDING GENERATION MARGINAL COST.

A. In opening testimony I proposed a number of changes to PGE's generation marginal cost study, including correcting a calculation error regarding the inclusion of wheeling costs in the CEP/IRP valuation of batteries, adjusting the salvage value of batteries from -5% to -0.5%, adjusting the overnight capital costs of batteries from $1,195 to $1,214, lowering the Effective Load Carrying Contribution ("ELCC") of batteries to 57% and removing capacity value from the cost of wind energy.

Q. HAVE OTHER PARTIES MADE GENERATION MARGINAL COST RECOMMENDATIONS?

A. In my review I did not identify any other parties recommending changes to PGE's filed generation marginal cost model. PGE's Reply Testimony of Robert Macfarlane and Ashleigh Keene makes the following response to my recommendations:

- Agree with AWEC's recommendation to adjust battery salvage cost to -0.5%.
- Agree with AWEC's recommendation to increase the overnight capital cost for batteries from $1,195 per kW to $1,214 per kW.
- Agree with AWEC's recommendation to remove wheeling costs from battery calculations.

Q. HOW DOES PGE RESPOND TO YOUR RECOMMENDATION TO REDUCE THE ELCC OF BATTERIES FROM 83% TO 57%, THE VALUE USED IN PGE'S IRP?

A. PGE notes that it made a model change and proposed changing ELCC from 83 to 80 percent. PGE argues against using the IRP's ELCC value of 57 percent for two reasons:

- PGE argues that the marginal cost model should reflect the ELCC of batteries in 2024 to be in alignment with the commercial operation date ("COD") date of the model of wind costs.
- PGE argues that the use of a 57 percent ELCC will result in dramatic swings in the marginal cost study.

Q. IS AN ELCC OF 57 PERCENT INCONSISTENT WITH A COD OF 2024?

A. No, it is not inconsistent to use an ELCC of 57% for a COD of 2024. First, it is incorrect to presume that assuming a COD date of 2024 also necessitates assuming the capacity deficit in 2024. Under this logic, in years where PGE has no capacity deficit PGE could model the ELCC using a de minimis amount of incremental resources. Second, the resources selected in

PGE's 2021 RFP include 331 MW of battery capacity with COD of 2024.[1] The 2021 RFP evaluated the capacity factor of these resources as 62.5 percent, which is more consistent with an ELCC of 57% than 80%.[2]

Q. WHAT IS THE BASIS FOR PGE'S PROPOSED ELCC OF 80%?

A. It is not clear what this ELCC is based on. PGE declined to provide the Sequoia models underlying the revised 80 percent figure.[3] PGE represented that the 83 percent figure was based on an assumed incremental addition of 50 MW.[4] PGE later clarified that the 83% figure resulted from the draft IRP and the 80% figure resulted from the revised IRP.[5] When asked what the ELCC of near-term battery additions is however, PGE noted that the 2023 IRP has not been acknowledged and provided the ELCC values used in the 2021 RFP docket, summarized in the table below.[6]

Table LK-9: 2021 RFP ELCC Values

	Capactiy Contribution in MW Bin			
Resource	**100**	**200**	**300**	**400**
Li-Ion Storage: 2-hr	63.0%	54.3%	45.7%	37.0%
Li-Ion Storage: 4-hr	84.0%	68.0%	62.5%	62.5%
Li-Ion Storage: 6-hr	92.0%	83.0%	76.0%	76.0%

1 PGE's 2023 IRP addendum, page 25, Table 8.
2 AWEC/701 (PGE Response to AWEC Data Request 296).
3 AWEC/701 (PGE Response to AWEC Data Request 297, 298, 300). PGE also declined to provide the ROSE-E model necessary to evaluate a more complex mix of incremental resources in response to AWEC DR 299.
4 AWEC/701 (PGE Response to AWEC Data Request 249).
5 AWEC/701 (PGE Response to AWEC Data Request 300).
6 AWEC/701 (PGE Response to AWEC Data Request 296).

Q. HOW DOES THE 2023 IRP ELCC VALUES COMPARE TO THE 2021 RFP ELCC VALUES?

A. In the 2023 IRP, PGE separately evaluated ELCC in summer and winter months. PGE evaluated 100 MW contribution bins from 100 MW to 2000 MW. The summer and winter contributions are summarized in the figures below.

Figure LK-2: PGE 2023 IRP Figure 147 Summer Storage ELCC

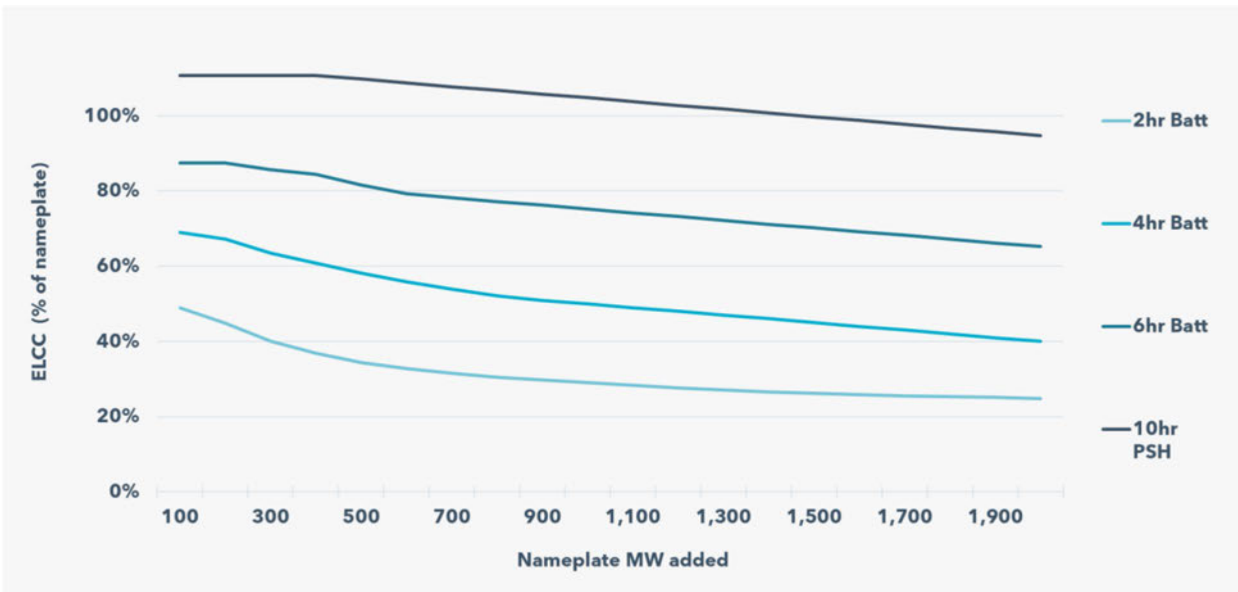
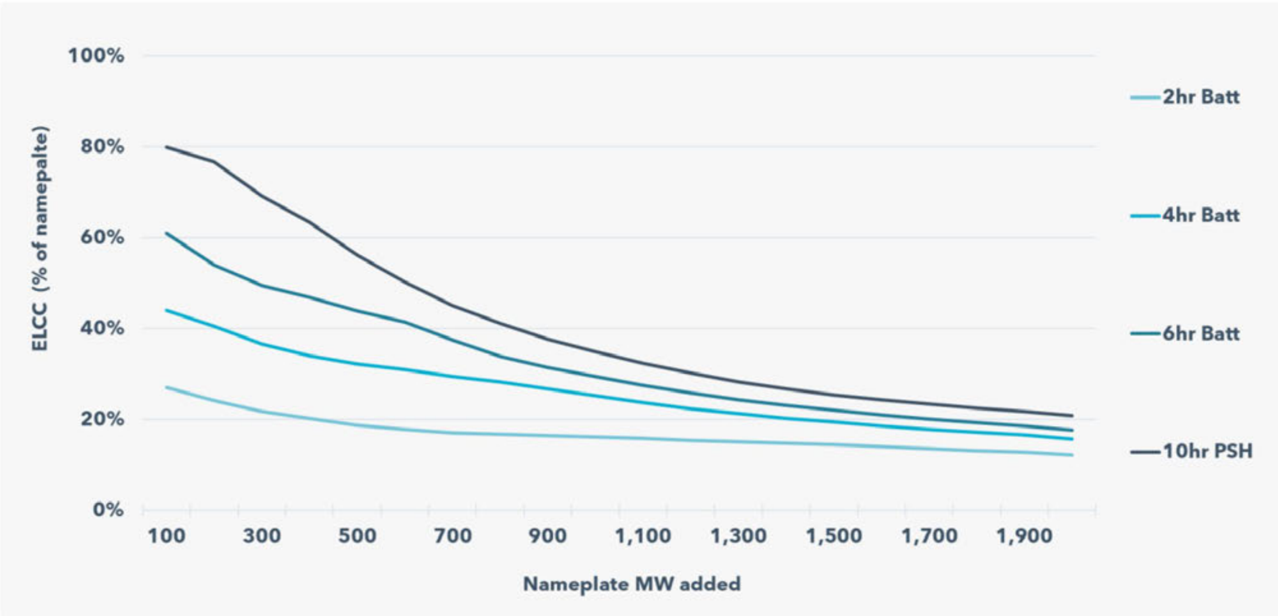


Figure LK-3: PGE 2023 IRP Figure 148 Winter Storage ELCC



Q. THE 2023 IRP ELCC FIGURES DO NOT INDICATE AN ELCC OF 80 PERCENT. CAN YOU EXPLAIN THIS?

A. Without access to the models underlying PGE's calculations it is not clear where PGE's 80 figure comes from. Table 50 of the 2023 IRP shows that 100 MW of incremental batteries for portfolio creation in year 2026 is 69 percent in the summer and 44 percent in the winter. PGE appears to use the average summer and winter values to represent overall ELCC, with 100 MW of batteries having an ELCC of 57% in the 2023 IRP.[7] PGE's 2023 IRP ELCC analysis appears to assume that 2024 and 2025 capacity needs are met through the 2021 RFP.[8] PGE appears to base its ELCC on the Sequoia model used in the 2023 IRP, with unspecified

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[7] PGE represents that the 57% value from the 2023 IRP is the average of the PGE Response to AWEC Data Request 249 (AWEC 302).
[8] PGE's 2023 IRP addendum, page 25, Table 8.

modifications to change the deficiency year from 2026 to 2024. It is not clear how the model was modified to achieve this deficiency.

Q. IS EITHER THE 80% OR 83 % ELCC A QUANTITY THAT HAS BEEN VALIDATED IN ANY OTHER PROCEEDING?

A. No. It appears these numbers were fabricated only for this rate case and are not consistent with either the 2021 RFP, the 2019 IRP, or the 2023 IRP.

Q. DOES USING A COD OF 2024 FOR THE BATTERY RESOURCE REQUIRE USING A 2024 DEFICIENCY YEAR?

A. No. There is no reason to link the COD to a deficiency year. This becomes obvious when considering a COD year where there is no deficiency. If there is no deficiency, there is no basis to specify a MW of incremental battery additions, and no basis to calculate capacity contribution for any level of incremental additions. Furthermore, long-term marginal cost studies typically presume that all resources are incremental resources. If all resources are treated as incremental resources, the MW of resource additions needs to be sufficient to meet all demand, not the 50 MW modeled by PGE.[9] Because the long-term marginal cost model treats all resources as incremental resources, there is no basis for limiting the ELCC to one based on a deficiency year in which there is no capacity shortfall.

Q. WHAT IS THE ELCC OF BATTERIES IF PGE'S 2021 RFP RESULTS AND 2021 RFP EVALUATION FRAMEWORK ARE USED?

A. PGE's 2021 RFP selects 311 MW of batteries in 2024, and 275 MW of batteries in 2025, a total of 586 MW.[10] Table LK-9 above shows that the ELCC for 300 MW of 4-hour batteries is

[9] PGE based its 83 percent (and presumably the subsequent 80 percent) ELCC on the assumption of 50 MW of incremental battery additions. PGE Response to AWEC Data Request 249.

[10] PGE Declined to provide the bids, bid evaluations, and contracts for these resources. AWEC/701 (PGE Response to AWEC Data Request 302).

62.5 percent. The 2021 RFP evaluation framework does not appear to have contemplated 586 MW of additions.

Q. WHAT IS THE ELCC OF BATTERIES IF PGE'S 2021 RFP RESULTS AND 2023 IRP ELCC SCHEDULES ARE USED?

A. Figure LK-2 shows the summer ELCC of 586 MW of 4-hour batteries to be approximately 58 percent and Figure LK-3 shows the winter ELCC of 586 MW of 4-hour batteries to be approximately 32 percent. This results in an average ELCC of 45 percent.

Q. WILL THE USE OF A 57 PERCENT ELCC RESULT IN DRAMATIC SWINGS IN THE MARGINAL COST STUDY?

A. No. Using an ELCC of 57% will provide a smooth transition to future cost models that are expected to have even higher costs of capacity and lower ELCCs for batteries. As shown above, the 2021 RFP resources alone result in an ELCC of 45 percent. On top of these resources, PGE's 2023 IRP addendum selects 1010 MW of "hybrid" solar plus battery storage and 400 MW of battery backed transmission by 2030.[11] This is a total of 1,996 MW of storage. PGE does not model the combined ELCC impacts of mixing standalone batteries with hybrid batteries and transmission batteries, however assuming these various storage resources follow the same curve as the 4-hour standalone curve, this results in a summer ELCC of 40% and a winter ELCC of 16%, or an annual average of 28%.

Q. SHOULD SUMMER, WINTER, OR AVERAGE ELCC BE USED?

A. PGE should use the ELCC that is binding on the system. This means that if PGE is adding resources to meet the winter peak, it is reasonable to use the winter ELCC. If PGE is adding resources to meet the summer peak, it is reasonable to use the summer ELCC. PGE is currently

[11] PGE's 2023 IRP addendum, page 25, Table 8.

a dual peaking utility. Furthermore, most of PGE's resources offer lower winter ELCC than summer ELCC. This means that winter capacity constraints are binding, and it is reasonable to use winter ELCC when evaluating costs. However, for this rate case AWEC recommends using the weighted summer and winter ELCC average because PGE's demand allocators include the summer and winter coincident peaks.

Q. DOES THE USE OF A 57% ELCC RESULT IN AN UNREASONABLE COST OF CAPACITY?

A. No. In UE 394 PGE's filed cost study allocated 31 percent of generation costs to demand.[12] PGE's filed cost study in this case allocates 30 percent of generation costs to demand. When PGE's filed study is modified to use an ELCC of 57 percent, it allocates 39 percent of generation costs to demand. This is far less than Washington's method of allocating 74 percent of costs to demand.[13]

Q. HOW DOES PGE RESPOND TO YOUR RECOMMENDATION TO REMOVE THE CAPACITY VALUE OF WIND FROM THE COST OF ENERGY?

A. PGE offers two concerns with removing capacity value from wind:

- PGE claims using the full cost of a wind resource aligns with the treatment given to the wind resource incorporated into the generation marginal cost study in UE 394.
- PGE argues that removing capacity value from wind may cause swings as PGE moves to an emissions free resource future.

[12] UE 394 / PGE / 1204 Macfarlane - Tang / 3
[13] Washington UTC Docket No. UE 230172 Exhibit No. RMM-1T Page 5 Line 20.

Q. HOW DO YOU RESPOND TO PGE'S CONCERN THAT THE UE 394 COST MODEL DID NOT REMOVE CAPACITY VALUE FROM WIND?

A. AWEC disputed the generation cost model in UE 394. Parties settled rate spread in UE 394 without stipulating to an agreed cost model. Therefore, UE 394 offers no precedent for this case. Furthermore, it is reasonable to make changes to cost of service models from year to year. In fact, PGE has proposed its own changes to the cost model in this case, invalidating this concern.

Q. HOW DO YOU RESPOND TO PGE'S CONCERN THAT REMOVING CAPACITY COSTS FROM WIND WILL CAUSE COST ALLOCATION SWINGS?

A. This issue mirrors PGE's concern with ELCC. PGE offers no evidence to support its assertion that accounting for capacity value will introduce cost swings. The most reasonable expectation for cost allocations is that as PGE approaches higher levels of emissions reductions, PGE's costs will be increasingly allocated to demand. Thus, it is incorrect to assert that beginning to account for this shift now will lead to swings. The table below illustrates the impact of accurately modeling costs in each period rather than ignoring cost changes. The table below compares the expected swings in the allocation of generation costs between demand and energy under AWEC's proposal, and PGE's proposal, assuming PGE maintains its model until 2030. The 2023 demand allocation reflects marginal costs modeled in UE 394.[14] The 2024 demand allocation reflects AWEC and PGE's respective proposals. The 2030 values reflect demand allocations using the expected ELCC values for incremental resources through 2030.[15] For interim years AWEC's values follow a linear path, reflecting linear incremental resource

[14] AWEC/200 Kaufman/49 line 3.

[15] Earlier in this testimony I demonstrate that the ELCC of the 2023 IRP preferred portfolio resource additions through 2030 have an ELCC of 28 percent. This ELCC leads to a demand allocation of generation costs of 68 percent.

additions. The PGE values represent no model changes until 2030 to represent PGE's preference for "minimizing allocation swings" by not reflecting actual costs in the cost model. PGE's approach results in a 38 percent allocation swing, while AWEC's proposal results in at most a 7 percent allocation change. Furthermore, PGE's proposal results in movements in opposite directions, while all of AWEC's movement is in the same direction. Thus, AWEC's proposal is more likely to reflect gradual cost allocation transitions than PGE's proposal.

Table LK-10: Allocation of Generation Costs to Demand

	AWEC		PGE	
Year	Demand Allocation	Change in Demand Allocation	Demand Allocation	Change in Demand Allocation
2023	43%		43%	
2024	50%	7%	30%	-13%
2025	53%	3%	30%	0%
2026	56%	3%	30%	0%
2027	59%	3%	30%	0%
2028	62%	3%	30%	0%
2029	65%	3%	30%	0%
2030	68%	3%	68%	38%

Q. HAS PGE CHALLENGED THE THEORETICAL BASIS FOR REMOVING CAPACITY VALUE FROM ENERGY COSTS?

A. No, PGE does not appear to dispute that energy costs are more accurately modeled by excluding capacity value. In fact, PGE admits that wind has capacity value and that removing the capacity value of wind results in a more accurate cost model.[16]

[16] AWEC/302 (PGE Response to AWEC Data Request 288).

III. DIRECT ASSIGNMENT OF SYSTEM DISTRIBUTION AND TRANSMISSION COSTS

Q. WHAT ISSUE DOES STAFF RAISE REGARDING DIRECT ASSIGNMENT OF DISTRIBUTION AND TRANSMISSION COSTS?

A. Staff notes that a large share of load growth in Hillsboro is associated with Schedules 89 and 90. Staff proposes directly assigning the costs associated with two projects, the Hillsboro Reliability Project and Horizon-Keeler #2 230kV line be directly assigned to Schedules 89 and 90.[17] PGE is requesting approval of $89.8 million in plant for two components of the Hillsboro Reliability Project is not requesting recovery of the Horizon-Keeler #2 230 kV line.

Q. WHAT IS YOUR RESPONSE TO STAFF'S RECOMMENDATION?

A. Staff's proposal results in double assignment of costs and is inconsistent with Oregon's use of marginal cost pricing, therefore the recommendation should not be accepted.

Q. ARE YOU AWARE OF ANY JURISDICTIONS THAT DIRECTLY ASSIGN SUBSTATION COSTS?

A. In Washington, PacifiCorp directly assigns substation costs to a schedule that is only available to customers with dedicated substations. Unlike Staff's proposal, dedicated substations are excluded from the secondary allocation any residual non-directly assigned substation rate base. Direct assignment of distribution and transmission costs is only tractable if these costs can be reasonably assigned without risk of double counting.

Q. ARE THERE DIFFERENCES BETWEEN WASHINGTON AND OREGON THAT MAKE DIRECT ASSIGNMENT IN OREGON IMPRACTICAL?

A. Washington allocates costs on an imbedded cost basis. Direct assignment is feasible when allocating based on embedded costs. However, when costs are modeled based on marginal

[17] Staff/2000 Stevens/40.

costs rather than embedded costs, it is not possible to directly assign costs. This is because the cost study evaluates the cost of building new facilities, while direct assignment assigns the cost of existing facilities.

Q. DOES STAFF'S PROPOSAL HAVE A REASONABLE COST BASIS?

A. No, Staff's proposal is not cost based because Staff's methodology will double charge large schedules for transmission and distribution expenses. As an example, suppose Staff's proposal is limited to Sch 90 and all of Sch 90's load is assumed to be served by the Hillsboro Reliability Project. Under Staff's proposal, PGE's filed marginal cost model is retained, and the full marginal cost of serving Sch 90 customers is used to allocate transmission and distribution costs to these customers. In addition to the full marginal cost allocation, Sch 90 would also be directly assigned the cost of the Hillsboro Reliability Project. Under this scenario, Sch 90 effectively pays 200 percent of substation costs, 100 percent by way of the allocated marginal cost and 100 percent by way of the embedded cost of service.

Q. IF THE COMMISSION ESTABLISHES A PRECEDENT BY APPROVING STAFF'S PROPOSAL, WHAT OTHER COSTS COULD EXPERIENCE SIMILAR HYBRID TREATMENT?

A. If the Commission approves direct assignment of specific projects, customers could request direct assignment of any projects that can reasonably be shown to serve only a subgroup of customers. For example, out of $1.6 billion in mainline distribution plant, there are 122 projects with a total of $323 million plant that could be directly assigned to customers under 200 kW. Similarly, substations that serve no large customer load could be directly assigned to smaller schedules.[18]

[18] Calculated from PGE workpaper "2024 Distribution Marginal Cost.xlsx".

Staff's proposal could also allow new customers to avoid certain historical costs. For example, the cost of uneconomic coal assets could be allocated based on historic load, so that new Schedule 90 customers would not pay for historically uneconomic investments. Alternatively, this precedent could allow customers to argue that new customer load be responsible to pay for new generation plus 100 percent of their allocated amount of existing generation costs.

Q. HOW DO THE MARGINAL TRANSMISSION AND DISTRIBUTION COSTS FOR SCHEDULE 89 AND 90 COMPARE TO THE DIRECTLY ASSIGNED COSTS THAT STAFF PROPOSES?

A. Under PGE's filed model, Schedules 89 and 90 rates are expected to collect $47 million per year in transmission and distribution revenue. Thus, in two years of service PGE will collect as much revenue as the cost of the Hillsboro Reliability Project included in rates.

Q. IF THE COMMISSION DECIDES TO APPROVE STAFF'S PROPOSAL, WHAT OTHER CHANGES SHOULD THE COMMISSION MAKE?

A. If the Commission approves Staff's proposal, it is critical to ensure no double counting of costs by excluding Schedule 89 and 90 from the marginal cost allocation of substation and sub-transmission costs.

IV. ENERGY AFFORDABILITY

Q. PLEASE SUMMARIZE THE ARGUMENTS MADE BY PARTIES REGARDING ENERGY AFFORDABILITY.

A. Parties make a number of recommendations with respect to energy affordability. AWEC addresses the following in this testimony:

- CUB's and CAPO's recommendation to eliminate the cap on contributions to Schedule 118 charges;

- CAPO's and CEP's recommendation to limit energy burden to 6% and increase the discounts available in the Income-Qualified Bill Discount ("IQBD") program;
- CAPO's recommendation to limit disconnections for non-payment; and
- CAPO's recommendation to implement "progressive" rates with "richer" customers paying higher rates.

AWEC will address some of the other procedural arguments these parties make in briefing as necessary.

Q. DO YOU HAVE ANY PRELIMINARY COMMENTS BEFORE ADDRESSING THE SUBSTANCE OF THESE ISSUES?

A. Yes. In general, the parties' proposals, particularly CAPO's and CEP's, would result in substantial additional costs borne by customers that do not qualify as "energy burdened" or "low-income" as the parties use these terms. AWEC understands and is sympathetic to the positions of these parties, but the fact is that it costs money to produce and deliver electricity and those costs have to be borne by someone. Effectively exempting certain customers from these costs – which is what some of the proposals would do, as discussed in more detail below – is unjust, unreasonable, and unsustainable.

The policies the parties promote would have material real-world impacts on other customers. For example, Puget Sound Energy ("Puget") recently requested that the Washington Utilities and Transportation Commission grant it relief from a requirement that prevents it from disconnecting customers with arrearage balances less than $1,000 as well as all known and estimated low-income customers.[19] As a consequence of this proposal, Puget is now facing "staggering and growing arrearage balances" that are "unprecedented."[20]

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[19] WUTC Docket Nos. UE-220066/UG-220067, Puget Sound Energy's Petition to Amend Final Order ¶ 10 (Aug. 10, 2023).

[20] *Id.* ¶ 9.

Specifically, Puget's arrearages have grown by 127% to $161 million.[21] If not recovered from the customers that owe these balances, they will need to be recovered from all other customers, resulting in an approximate 4.8% electric rate increase, assuming these balance do not grow.[22] This level of impact must be considered in the context of other rate increases customers are facing due both to market conditions and state policies.

These increasing costs are having an impact. Earlier this month, WestRock announced it was closing its Tacoma paper mill, resulting in the loss of 400 jobs. Other recent closures in the Northwest include Aloca's Intalco Works aluminum smelter,[23] Columbia Steel Casting Company's facility in Portland,[24] and SP Fiber Technologies' paper mill in Newberg.[25] While many forces are at play in these closures, increased operating costs is one of them, and electricity is a major operating cost for these types of energy-intensive businesses. I would note that, while Staff testifies that it "represents the interests of all customer classes,"[26] its testimony does not address the potential impacts of requiring Oregon's businesses to assume substantially greater than their share of costs.

In addition to the cost impacts, these proposals inherently rely on a premise that, at least today, is not state policy. Specifically, they are supported by an assumption that electricity is a "basic necessit[y]" that must be "available to all humans without financial stress."[27] AWEC is not taking a position on that premise here. Whatever the merits of this position are, it is not the

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21 *Id.*
22 *Id.* ¶ 12.
23 Alcoa Announces Closure of Intalco Smelter and Prepares Site for Redevelopment | Alcoa Corporation
24 121-year-old Portland business to close, lay off workers - oregonlive.com
25 Newberg pulp, paper mill to close 'indefinitely;' more than 200 jobs affected - oregonlive.com
26 Staff/600, Scala/23:12.
27 CAPO/100, Springer/3:15-16.

premise that governs the provision of electricity in Oregon. If it were, this service would not be provided by private companies with shareholders entitled to the opportunity to earn a return; it would be provided by the government and funded through taxation rather than utility rates. Moreover, even when electricity is provided by the government – through a municipality or People's Utility District, for instance – I am not aware of a single such entity that has the types of energy burden and disconnection restrictions the parties advocate for here. The Portland Water Bureau, for example, a government-run entity that provides a commodity at least as much of a "basic necessit[y]" as electricity, does not guarantee uninterrupted service regardless of non-payment or provide the level of rate discount being advocated for here. Indeed, it recognizes the same need to balance conflicting obligations and goals that the Commission has in crafting just and reasonable rates:

> We want community members to be able to pay their bills without sacrificing other essentials such as food, housing, heat, medical services, childcare, and transportation. At the same time, we must maintain levels of service that comply with federal, state, and local regulations. Our goal in navigating these two commitments is to provide safe and reliable drinking water to all Portlanders without creating an unsustainable economic burden for the communities, households, and businesses we serve.[28]

To be sure, the State has recently emphasized the need for energy affordability and environmental justice through legislation and policy guidance,[29] which are being implemented through programs such as the IQBD, but it has so far resisted the extreme proposals being advocated for here.[30] That is because these proposals may lead to severe negative unintended

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28 RAMP: Regulated Affordable Multifamily Assistance Program | Portland.gov; *see also*, FAQs: Financial assistance for your sewer, stormwater, and water bill | Portland.gov

29 *See* Staff/600, Scala/10:3-12:21.

30 *See infra*, n. 40

consequences, including "unprecedented" arrearage balances for PGE and the closure of major employers in the region. The Commission should reject these proposals.

a. <u>Schedule 118 Cap</u>

Q. PLEASE DESCRIBE PGE'S SCHEDULE 118.

A. Schedule 118 is PGE's tariff that recovers the costs of its Income-Qualified Bill Discount Program. This program provides graduated bill discounts to low-income customers. Because these customers pay less for their electricity than PGE's cost of service, these costs are recovered from other customers through Schedule 118. These costs are recovered through a flat rate to residential customers and per kWh charge to non-residential customers, with charges capped at $1,000 per month per site. While this means that no customer pays more than $12,000 per year per site, some customers have multiple sites, meaning they pay substantially more in the aggregate.

Q. WHAT DO PARTIES RECOMMEND WITH RESPECT TO THE PER-SITE CAP ON SCHEDULE 118?

A. CUB recommends that it be eliminated entirely. CAPO recommends that "mega customers … contribute more" under this tariff, but is not more specific.[31] Staff also recommends that the cap "be revisited at such time that enrollment, costs, or other relevant metrics or design elements of the IQBD have changed to warrant an adjustment to this feature."[32]

Q. DOES AWEC AGREE WITH THESE PROPOSALS?

A. No. CUB's proposal to eliminate the cap would have a disproportionate effect on PGE's largest customers – customers that, as a class, have no opportunity to benefit from this

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[31] CAPO/100, Springer/35:7-8.
[32] Staff/600, Scala/44:10-12.

program. Residential customers currently pay $1.14 per month under Schedule 118, equivalent to $13.68 per year. While PGE projects this amount to increase to $2.30 per month in its Reply Testimony,[33] that still amounts to only $27.60 per year. Meanwhile, eliminating the cap would reduce residential customer payments by $0.63 per month, or $7.56 per year but would result in monthly payments of as much as $93,000 for PGE's largest customers.[34] Again, because this charge is per site, any customer that has multiple sites would have an exponentially higher cost under this program. Some customers will pay well over $1 million per year for PGE's IQBD program. In other words, eliminating the cap will impose substantial incremental costs on PGE's large customers while doing very little to mitigate the cost for residential customers.

Q. DOES PGE SUPPORT REMOVING THE CAP?

A. No, PGE continues to support a cap on these costs for large customers. PGE notes that removing the cap would result in energy-intensive customers experiencing bill impacts "that are not indicative of their size."[35] In other words, while CUB argues that the current cap disproportionately impacts residential customers, removing the cap would disproportionately impact large customers.

Q. IS AWEC OPEN TO AN ALTERNATIVE TO THE CURRENT CAP?

A. Yes. CUB's position is valid that, if the costs of PGE's IQBD program increase, none of those costs will be borne by customers subject to the current $1,000 cap. AWEC does not believe that an increase to the costs of the IQBD program is necessary or justified; however, if the Commission does determine to expand this program such that its costs rise, AWEC would be

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[33] PGE Exh. 2600 Work Paper Sch 118 Impacts
[34] *Id.*
[35] PGE/2600, Macfarlane-Pleasant/39:2-3.

open to increasing the cap by the percentage increase in the overall costs of the program. In other words, if the Commission approves a change to the IQBD program that increases the costs of that program by 20%, the $1,000 cap in Schedule 118 would also increase by 20%. This will ensure that large customers pay their proportional share of any increase.

Q. WHAT OTHER ALTERNATIVES TO THE CURRENT CAP COULD THE COMMISSION CONSIDER?

A. Schedule 118 and the IQBD program were implemented under HB 2475, passed in the 2021 Legislative Session. That bill allows the Commission, as part of "a comprehensive classification of service for each public utility," to consider "differential energy burdens on low-income customers" and related factors.[36] As a replacement to Schedule 118 and the IQBD program, PGE could consider proposing a low-income rate class in its next general rate case. To be clear, however, because Schedule 118 currently implements the provisions of HB 2475, it should be eliminated if a low-income rate class is created. Having both Schedule 118 and a low-income rate class would be duplicative and would lead to unacceptable cost impacts on other customers, as discussed above.

b. <u>Limit Energy Burden to 6% and Increase Funding Under the IQBD Program</u>

Q. WHAT DO CAPO AND CEP RECOMMEND WITH RESPECT TO ENERGY BURDEN?

A. Both parties recommend that the energy burden of residential households be limited to six percent.[37] In other words, residential customers should not pay more than six percent of their

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[36] HB 2475 § 2(1).

[37] CAPO/100, Springer/5:17-18; CEP/100, Fain/2:11-14.

income on energy. CEP further recommends that the discount levels in the IQBD program be increased to absorb the rate increase from this case for eligible customers.[38]

Q. WHAT IS AWEC'S POSITION ON THESE RECOMMENDATIONS?

A. AWEC does not support these parties' proposals for the reasons discussed at the beginning of my testimony. As energy is a major cost for many industrial customers, AWEC understands the goal and desire to reduce energy burden, but the proposal to limit energy burden to six percent effectively caps a residential customer's electricity bill, which will exacerbate cost shifting to other customers. Moreover, this proposal is not fully developed and it is unclear how it would be implemented. Many residential customers have both electricity and natural gas. If the overall energy burden is to be capped at 6%, it is unclear how PGE would limit the cost of electricity to these customers so that their aggregate cost of electricity and natural gas does not exceed 6%.

Furthermore, enforcing a 6% cap would require a level of information precision that likely does not exist. Even if PGE had access to a customer's income through tax returns or other means, that income fluctuates year-to-year, as does energy consumption. The administrative burden necessary to ensure energy costs do not exceed 6% of household income would be daunting and would likely further increase costs to other customers, just to implement this cap.

With respect to increasing assistance under the IQBD program to eliminate any cost increase from this case, the result is that all other customers will pay these increased costs. While AWEC believes PGE's rate increase should be substantially lower than it requests, PGE

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[38] CEP/100, Fain/3:2-5.

frames the cost increase as necessary to "respond to the rapidly changing environment" and due to the "extraordinary transformation of our operating environment and region – including policy requirements, resource mix, market structures, customer demand and end-uses, and power flows across the system."[39] Much of this transformation stems from the transition from dispatchable fossil-fueled resources to variable renewable energy resources. CEP's position is effectively that certain customers should be exempt from paying the costs of this transition, which is neither reasonable nor equitable.

Q. ARE THERE OTHER REASONS THE COMMISSION SHOULD NOT ADOPT A 6% ENERGY BURDEN CAP?

A. Yes. This year, the Legislature considered a bill to limit collections from utility customers that have energy burdens greater than six percent.[40] This bill failed to pass. If the Legislature did not act on this proposal, the Commission should not take a contrary action, particularly in the same year.

c. <u>Limit Disconnections for Non-Payment</u>

Q. WHAT DOES CAPO PROPOSE WITH RESPECT TO DISCONNECTIONS FOR NON-PAYMENT?

A. CAPO recommends that PGE "reduce the number of disconnections for non-payment."[41] This would be accomplished by PGE adopting "a maximum disconnection rate performance metric" and if "disconnections rise above that rate, disconnections should be halted until new approaches can be put into place to prevent excessive disconnections."[42] CAPO does not propose a specific "disconnection rate performance metric," but does state its position that

[39] PGE/1600, Pope-Sims/4:1-5.
[40] HB 3459 (Introduced)
[41] CAPO/100, Springer/5:18-19.
[42] *Id.* at 36:1-3.

"any electricity rate that disconnects households, who cannot afford to pay, is neither just nor reasonable."[43] Thus, while the specifics of CAPO's position do not appear to be fully developed, it appears that CAPO is advocating for eliminating PGE's ability to disconnect at least some customers for non-payment.

Q. WHAT IS AWEC'S POSITION ON THIS PROPOSAL?

A. Again, as with many other proposals put forward by the parties on these issues, CAPO's position is understandable in a vacuum, but it would be highly problematic if were actually implemented. Puget's quickly growing arrearage balance amply demonstrates this.[44] Simply put, a customer that cannot be disconnected for non-payment is a customer that has no incentive ever to pay their bill and, again because of Puget's circumstance, there is clear evidence that this is exactly what would happen if a similar restriction were to be imposed on PGE. That is an unfair burden to put on other customers.

d. <u>"Progressive" Rates</u>

Q. WHAT IS CAPO'S RECOMMENDATION ON THIS ISSUE?

A. CAPO states that "[r]ates should be generally progressive, analogous to taxations, reflecting households varying ability to contribute to the public good."[45] Thus, according to CAPO, "richer residential customers, commercial and industrial customers, as well as executives and shareholders" should pay higher rates relative to lower income residential customers.[46]

Q. WHAT IS AWEC'S POSITION ON CAPO'S PROPOSAL?

A. Once again, AWEC opposes this proposal on policy, economic, and practical grounds.

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43 *Id.* at 15:16-17.
44 *Supra* n. 19
45 CAPO/100, Springer/36:10-11.
46 *Id.* at 5:21-23.

Q. WHAT ARE AWEC'S POLICY CONCERNS WITH THIS PROPOSAL?

A. As discussed above, CAPO's position on this issue is based on the premise that electricity is a "public good."[47] That premise, however, is at this time only aspirational. At least for customers in PGE's service territory, electricity is a commodity provided by a private corporation with an obligation to maximize profits for its shareholders. CAPO is free to push for a state-wide policy change in which the obligation to provide electricity is assumed by the government and is paid for through a progressive tax, but until that time, the Commission's obligation is to ensure that PGE's rates are just and reasonable, which has traditionally been interpreted to mean the lowest possible rates that provide PGE shareholders with an opportunity to earn a reasonable return.

Q. WHAT ARE AWEC'S ECONOMIC AND PRACTICAL CONCERNS WITH THIS PROPOSAL?

A. Primarily, the proposal does not provide a solid theoretical basis for designing rates and that can actually be implemented. Rates are typically established based on the cost to serve a class of customers. While no customer ever pays precisely its cost of service, this theoretical construct provides a framework on which an evidentiary basis for a utility's rates can be established. As Staff notes, abandoning cost-causation principles "would risk compromising the economic viability and stability of the energy sector."[48] The type of "progressive" rates CAPO envisions, by contrast, do not have the same theoretical foundation, at least as proposed, and therefore are likely to increase controversy and reduce transparency when setting rates.

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47 *Id.* at 36:11.

48 Staff/600, Scala/16:16-18.

For instance, CAPO does not explain what it means for certain customers to be "richer" than others. Industrial customers certainly have a higher gross income than residential customers, but that does not necessarily mean that they also have a high profit. Indeed, in some years businesses may operate at a loss. Under CAPO's proposal, would this mean that such a customer would receive free electricity for that year? Moreover, when would a determination of the proper rate a customer pays be made, given that total income is not known until at least the end of a year? And would income be measured based on the specific facility served by PGE, or if that facility is owned by a larger company, would the company's consolidated income be the measuring standard? Further complicating all of these issues would be the need for PGE to have access to the financial information of all of its customers.

Finally, while I am not a lawyer, I understand that PGE's rates cannot be discriminatory, which generally means that it cannot charge different rates to customers within the same rate class. Thus, PGE would seemingly need to entirely redesign its rate schedules to implement CAPO's recommendation.

V. WORLD TRADE CENTER

Q. PLEASE SUMMARIZE YOUR OPENING TESTIMONY RECOMMENDATIONS REGARDING THE WORLD TRADE CENTER.

A. In Opening Testimony, I recommended reducing the cost of the World Trade Center ("WTC") rent expense to reflect the lower of cost or market standard, as calculated by AWEC in UE 394.

Q. WHAT WAS PGE'S RESPONSE TO YOUR RECOMMENDATION?

A. PGE makes three arguments against AWEC's proposed affiliated interest transfer price. First, PGE argues that the WTC has never been paid for through rate base or other means. Second, PGE argues that it has rented the WTC from its affiliate, 121 SW Salmon since 1978 at below market rates. Third, PGE argues that the equity value of the WTC continues to be encumbered.[49]

Q. WHAT IS YOUR RESPONSE TO PGE'S ARGUMENTS?

A. While I have specific responses to each point, none of PGE's arguments invalidate the application of the lower of cost or market standard for affiliated interest transactions. The lower of cost or market standard is a regulatory standard that goods and services provided by an affiliate or the non-utility operations of a regulated company should be transferred at the lower of the cost of providing the service or the prevailing market rate. This standard is established in OAR 860-027-0048(3)(e):

> When services or supplies (except for generation) are transferred or provided to a regulated activity by a nonregulated activity, transfers shall be recorded in regulated accounts at the nonregulated activity's cost or the market rate, whichever is lower. The nonregulated activity's cost shall be calculated using the energy utility's most recently authorized rate of return.

There are no clauses in OAR 860-027-0048 that revoke or otherwise invalidate this rule for the three reasons identified by PGE. The lower of cost or market standard applies to the provision of services from assets that have never been paid by customers, to the provision of services that have previously been provided at the lower of cost or standard, and to the provision of services that involve encumbered assets.

[49] PGE / 1700 Batzler- Ferchland / 57

Q. IS THE APPLICATION OF THE LOWER OF COST OR MARKET STANDARD RELEVANT TO THE WTC?

A. Yes, in fact, the nature of this particular relationship makes strict adherence to the lower of cost or market standard more relevant than most transactions. This is because PGE has relied on the financial benefits its rental decisions have on the profitability of 121 SW Salmon to justify regulated investments. This entanglement of decision-making processes and financial outcomes across PGE and its affiliate can only be reconciled through strict application of the lower of cost or market standard.

In 2018, concurrent with 121 SW Salmon's purchase of the WTC, PGE evaluated whether to invest $215 million in its integrated operations center,[50] which would relocate PGE office space from the WTC to an alternate location. The funding request for this project states that a benefit justifying this $215 million dollar investment to be the [redacted].[51] PGE's intention to monetize the vacated space through its unregulated affiliate is confirmed by PGE's forecasted lease square footage. In 2021, PGE intended to reduce its square footage rented from the WTC from 317,778 to 232,636, a reduction of 120,000 from its pre-purchase square footage rent.[52]

This means that PGE is unable to operationally segregate 121 SW Salmon financial decisions from regulated utility decisions. In this situation, it is the Commission's role to protect ratepayers by upholding the lower of cost or market standard.

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[50] UE 394 / PGE / 800 Bekkedahl – Jenkins / 4.
[51] AWEC/701 (UE 394 PGE First Supplemental Response to OPUC DR 657 Confidential Attachment).
[52] AWE/701 (UE 394 PGE Response to AWEC Data Request 080).

Q. IS PGE CORRECT THAT OWNERSHIP OF THE WTC COMPLEX HAS NEVER BEEN PAID FOR BY CUSTOMERS THROUGH RATE BASE OR ANY OTHER MEANS?

A. No, this is not accurate. As the anchor tenant, the ownership cost of the WTC has been in customer rates since Docket No. UE 394, which was the first rate case after 121 SW Salmon's purchase of the WTC. Furthermore, PGE misrepresents the nature of risk involving 121 SW Salmon. As the anchor tenant, PGE rents more than 50% of the floor space of 121 SW Salmon. As the largest tenant of the WTC, and an affiliated interest, PGE greatly reduces the risk to 121 SW Salmon for the purchase and ownership of the building.

Q. IS THE TRANSFER PRICE FOR THE WTC RELEVANT TO THE APPROPRIATE TRANSFER PRICE AFTER 121 SW SALMON'S PURCHASE OF THE WTC?

A. No, consideration of prior year transfer prices would constitute retroactive rate making. PGE would have to have filed a deferral for prior year rents for any shortfall in prior year rents to be included in today's rates. PGE has not indicated that it currently has such a deferral.

The nature of PGE's affiliated interest transaction changed materially when PGE purchased the WTC. This is evident by the fact that PGE filed for a new affiliated interest transaction in Docket No. UI 405 as part of its purchase of the WTC. The purchase of the WTC materially reduced 121 SW Salmon's cost of renting to PGE, and this reduced cost should be reflected in rates regardless of the cost to offer rent to PGE prior to the purchase.

Q. HOW IS THE ENCUMBERANCE OF THE WTC RELEVANT TO PGE'S AFFILIATED INTEREST RENTAL PRICE?

A. PGE recognizes that the lease encumbrance on the WTC reduced its cost to purchase the WTC through 121 SW Salmon. PGE also admits that PGE could have purchased 121 SW Salmon as a utility asset.[53] PGE's admission of the presence of an encumbrance, combined with PGE's

[53] AWEC/701 (PGE Response to AWEC Data Request 314).

failure to dispute AWEC's calculation of the carrying costs of the WTC, support a finding that the cost of renting space to PGE is lower than PGE's proposed transfer price.

Q. PGE DOES AGRUE THAT AWEC'S PROPOSED TRANSFER PRICE IS BASED ON A 25-YEAR ANALYSIS AND RELIES ON AN ASSUMED SALE OF THE PROPERTY. IS THIS CORRECT?

A. My model calculates the long-term cost of owning the WTC but it does not assume a sale of the property. Instead, the model calculates the terminal value of the property at the end of 25 years. This is appropriate and standard for evaluating investments in real estate. PGE incorrectly concludes that a sale must occur for my model to be valid, and PGE incorrectly concludes that return on investment cannot be calculated without knowing the exact future outcomes. Investment decisions in real estate considers both cash flow from operations and expected appreciation of property.

Q. COULD YOU HAVE PERFORMED A SHORTER-TERM ANALYSIS AND ARRIVED AT A SIMILAR RESULT?

A. Yes. PGE states that its equity in the WTC cannot be realized for 25 years.[54] The encumbrance on the WTC decreases each year as the number of years of the WTC lease decreases. The encumbrance also decreases as PGE's square footage rental of the WTC decreases, such as the 25% reduction in leased square footage that occurred with the completion of the IOC.[55] I could have calculated a lease price based on a shorter lease period, such as 5 or 10 years. However, this introduces complexities associated with recalculating the interim amount of the encumbrance. It also introduces the need to periodically revisit the appropriate transfer price.

[54] PGE / 1700 Batzler - Ferchland / 62 line 7.
[55] AWEC/701 (PGE Response to AWEC Data Request 207).

Furthermore, PGE offers no indication that it expects to vacate the WTC in less than 25 years. Thus, a longer-term analysis is appropriate.

Q. CAN YOU PROVIDE THE CONFIDENTIAL DISCOVERY WHICH ARE REFERENCED IN AWEC EXHIBIT 307?

A. Yes, these exhibits are included in Exhibit AWEC 701.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 416

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

CONFIDENTIAL EXHIBIT AWEC/701

(REDACTED VERSION)

May 9, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 207
Dated April 25, 2023

Request:

Please provide the total square feet leased by PGE for the WTC from 2015 to present.

Response:

The following table provides the requested information.

Year	2015	2016	2017	2018	2019	2020	2021	2022	2023B	2024F
PGE Leased SqFt	352,388	333,436	336,896	336,891	336,151	331,363	317,778	256,433	256,433	256,433

August 7, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 296
Dated July 31, 2023

Request:

Please refer to PGE/2500, Macfarlane – Keene / 3 lines 9 and 10.

a. Is it PGE's position that the cost of demand will increase or decrease relative to energy in the future?
b. If PGE believes the cost of demand will decrease relative to energy in the future, please explain why.
c. Please refer to PGE's 2023 IRP addendum, page 25, Table 8, which shows 475 MW of batteries added in 2025 and 2026. What is PGE's understanding of the combined ELCC for these additions? If PGE calculated ELCC as part of the selection of these RFP resources, please provide the supporting workpapers.
d. Does PGE agree that as PGE adds more storage to its system, the ELCC of storage will decline? If no, why not?

Response:

a. PGE objects to this request in that it is vague and calls for speculation.

b. PGE objects to this request as it is vague and calls for speculation.

c. PGE objects to this request in that it calls for new analysis. Without waiving said objection, PGE states as follows:

As of the writing of this response, PGE's 2023 IRP has not been acknowledged by the Commission. Attachment 296-A provides the ELCC calculator values publicly provided in the 2021 RFP docket.

d. All other modeling assumptions constant, yes, as additional storage resources are added to a system, the ELCC values of the additional resources would decline.

Resource	Li-Ion Storage: 4-hr
Size	200 MW
Approximate Capacity Contribution	152 MW

Marginal MW	100	200	300	400	500	600	700	800
MW Bins	100	100	0	0	0	0	0	0
Bin Contribution	84	68	0	0	0	0	0	0
	2	3	4	5	6	7	8	9

	Capactiy Contribution in MW Bin							
Resource	**100**	**200**	**300**	**400**	**500**	**600**	**700**	**800**
Solar	5.5%	5.0%	4.5%	4.0%	4.0%	2.7%	2.7%	2.7%
Solar plus Storage: 4-hour Duration, 25% Battery:Solar MW	21.3%	20.9%	20.6%	20.3%	20.0%	19.6%	19.3%	19.0%
Solar plus Storage: 6-hour Duration, 50% Battery:Solar MW	51.3%	48.4%	45.5%	42.6%	39.7%	36.8%	33.9%	31.0%
Wind: Gorge	25.0%	24.0%	20.0%	17.0%	12.0%	10.0%	10.0%	8.0%
Wind: Ione	12.0%	10.5%	9.0%	7.5%	6.0%	4.0%	4.0%	4.0%
Wind: SE WA	26.0%	22.0%	14.0%	10.0%	9.0%	7.0%	5.0%	3.0%
Wind: MT	43.0%	40.0%	24.0%	16.0%	11.0%	11.0%	7.0%	6.0%
Li-Ion Storage: 2-hr	63.0%	54.3%	45.7%	37.0%				
Li-Ion Storage: 4-hr	84.0%	68.0%	62.5%	62.5%				
Li-Ion Storage: 6-hr	92.0%	83.0%	76.0%	76.0%				
Pumped Hydro Storage: 8-hr	94.0%	93.0%	88.5%	88.5%				

These results are for informational purposes only to aid in Bidder self-scoring. Estimates based on PGE's 2019 IRP update and subject to change. Estimated results are as of December 2021.

Results are based on proxy resources.

August 7, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 297
Dated July 31, 2023

Request:

Please refer to PGE/2500, Macfarlane – Keene / 3.

a. Please provide access to a functional version of ROSE-E with all reference case inputs, parameters, and constraints used in PGE's 2023 IRP and PGE's Addendum Filing filed on July 7, 2023 in Docket LC 80.
b. Please provide access to a functional version of Sequoia and all associated workpapers supporting PGE's 2023 IRP and PGE's Addendum Filing filed on July 7, 2023 in Docket LC 80.
c. Please provide all documentation related to setting up and running the ROSE-E model and Sequoia model.

Response:

a. PGE objects to this request on the basis that it seeks proprietary modeling information, is not relevant and is not likely to lead to the discovery of relevant information in this general rate case.

b. PGE objects to this request on the basis that it seeks proprietary modeling information, is not relevant and is not likely to lead to the discovery of relevant information in this general rate case.

c. PGE objects to this request on the basis that it seeks proprietary modeling information, is not relevant and is not likely to lead to the discovery of relevant information in this general rate case.

August 7, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 298
Dated July 31, 2023

Request:

Please refer to PGE/2500, Macfarlane – Keene / 5 lines 7 to 18.

a. Please provide all workpapers used to calculate the tuned ELCC in the referenced lines.
b. Could the cost of wind be calculated with a COD of 2026 to be in alignment with a battery COD of 2026? If no, why not? If yes, please provide such calculations or explain what changes PGE would find necessary and acceptable to calculate a wind COD of 2026.
c. What level of deficiency was assumed for 2024 and 2026? Please provide this information as used in the cost-of-service study, the 2023 IRP, and the 2023 IRP addendum.

Response:

a. In PGE/2500, Macfarlane – Keene/5 line 8, PGE states that the ELCC used in the marginal cost of capacity calculation was developed in a tuned system. This was not accurate and the ELCC values used original cost study (confidential workpaper in Exhibit 1200, 2024 Generation Marginal Cost_CONF.xlsx) and the revised cost study (confidential workpaper in Exhibit 2500, 2024 Generation Marginal Cost Work Papers Revised_CONF.xlsx) are both reflective of an untuned system.

b. Given that the 2023 IRP was not yet filed at the time PGE was conducting its generation marginal cost study for this general rate case, we attempted using selected bids from PGE's 2021 All Source RFP as proxy resource inputs. This approach worked for the energy resource (Clearwater wind facility) but a capacity resource bid had not been awarded at that time. For this reason, PGE pulled inputs from our draft 2023 IRP for a battery resource and adjusted them to better align with the proxy energy resource (COD 2024).

It would be possible to instead conduct a generation marginal cost study using only draft IRP inputs with COD 2026, but PGE recommends the approach we have taken because COD 2024 aligns with the GRC target year and the 2023 IRP is still undergoing the regulatory review process and has not been acknowledged by the Commission.

PGE objects to the final request in part (b) on the basis that it is unduly burdensome to essentially conduct a third marginal cost of energy analysis. PGE has already provided a similar analysis based on a solar resource in AWEC DR 250 (a).

c. The capacity needs modeled for 2024 are 248 MW in the annual base scenario. For 2026, they were 506 MW in the summer base scenario and 430 MW in the winter (draft 2023 IRP). In the model refresh used for 2023 IRP addendum, the 2026 capacity needs are 718 MW in the summer base scenario and 522 MW in the winter base scenario.

August 7, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 299
Dated July 31, 2023

Request:

Please refer to PGE/2500, Macfarlane – Keene / 6 lines 3 to 11. Please also refer to the response to AWEC DR 297.

a. Please identify each ROSE-E input file that needs to be modified to increase the capacity need in each year and season for every price, technology, and hydro by 200 MW. If making such changes requires access to additional models, such as Aurora, please provide such access or provide such updated inputs.
b. Please identify each ROSE-E input file that needs to be modified to increase the capacity and energy need in each year and season for every price, technology, and hydro by 200 MW. If making such changes requires access to additional models, such as Aurora, please provide such access or provide such updated inputs.
c. Please confirm that the ROSE-E output file “annual_costs.txt” reflects the annual revenue requirement in $1000 for the associated portfolio. If not confirmed, please explain what this file represents.
d. Please confirm that the ROSE-E output file “annual_cost.txt” field “New Resource Revenues” reflects revenues in $1000 from selling excess generation. If not confirmed, please explain what this field represents.

Response:

PGE objects to requests (a) – (d) on the basis that they are overly broad, unduly burdensome, require new analysis and are not relevant nor likely to lead to the discovery of relevant information in this general rate case.

August 7, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 300
Dated July 31, 2023

Request:

Please refer to PGE/2500, Macfarlane – Keene / 6, lines 12 to 14. Please provide the Sequoia files associated with the referenced text and explain the change.

Response:

PGE objects to this request on the basis that it seeks proprietary modeling information and calls for speculation. Without waiving its objection, PGE responds as follows:

As indicated in PGE's opening testimony Exhibit 1200/4,14-5,5, PGE uses a generic 4-hour utility-scale battery as a proxy capacity resource. The change from 83% to 80% is the result of going from the draft to the final IRP model, which was finalized after PGE's opening testimony was filed.

August 7, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 302
Dated July 31, 2023

Request:

Please refer to PGE's 2023 IRP addendum, page 25, Table 8. Please provide the bids, bid evaluations, and contracts or draft contracts with four 2021 RFP resources in this table.

Response:

PGE objects to this request as overly broad, unduly burdensome, seeking information subject to confidentiality agreements, irrelevant, and unlikely to lead to the discovery of relevant information in PGE's general rate case.

August 7, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 314
Dated July 31, 2023

Request:

Please refer to PGE/1700, Batzler – Ferchland / 56.

a. Is 121 SW Salmon a wholly owned subsidiary of PGE?
b. Could PGE have purchased the WTC as utility property? If no, why not?

Response:

a. Yes. 121 SW Salmon is a wholly owned, non-utility subsidiary of PGE.

b. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 394

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

CONFIDENTIAL EXHIBIT AWEC/202

PGE RESPONSES TO DATA REQUESTS

PROTECTED INFORMATION
SUBJECT TO GENERAL PROTECTIVE ORDER

August 24, 2021

To: Jesse O. Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to AWEC Data Request 016
Dated August 10, 2021

Request:

Please refer to PGE's initial application for affiliated interest transaction in Docket No. UI 405.

a. Please provide all filings, workpapers and discovery prepared by PGE as part of Docket No. UI 405.
b. Did PGE or a PGE affiliate complete the purchase described in Docket No. UI 405? If no, why not? If yes, please provide the purchase agreement and other closing documents.
c. Please provide PGE's current lease for the World Trade Center Complex.

Response:

a. PGE objects to this request on the basis that it is unduly burdensome and that some of this information is publicly available. Without waiving its objection, PGE responds as follows:

   Confidential Attachment 016-A provides UI 405 Information Request Nos. 1 – 12.

   For PGE's initial application and reply comments, see:

   https://apps.puc.state.or.us/edockets/docket.asp?DocketID=21450

b. Yes. PGE's affiliate 121 SW Salmon Street Corporation purchased the World Trade Center Complex. See confidential Attachment 016-B for the purchase agreement, the final settlement statement, and the special warranty deed.

c. Confidential Attachment 016-C provides PGE's current lease for the WTC Complex.

Confidential Attachments 016-A, 016-B, and 016-C contain protected information and are subject to General Protective Order No. 21-206.

July 6, 2018

TO: Lance Kaufman
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UI 405
PGE Response to OPUC Information Request No. 003
Dated June 22, 2018

Request:

Please provide all financial analysis of 121 SW Salmon's purchase of the WTC.

Response:

PGE objects to this request as overly broad and unduly burdensome. Subject to and without waiving its objection, PGE responds as follows:

Attachment 003-A provides the financial model for 121 SW Salmon's purchase of the WTC. Attachment 003-A is protected information and subject to Protective Order 18-261.

UI 405

Attachment 003-A

Provided in Electronic Format only

Protected Information Subject to Protective Order 18-261

Pages 15 - 39 of Exhibit/701 contain Protected Information Subject to Modified General Protective Order and have been redacted in their entirety.

July 6, 2018

TO: Lance Kaufman
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UI 405
PGE Response to OPUC Information Request No. 004
Dated June 22, 2018

Request:

Please list all presentations made to Portland General Electric Company (PGE) and PGE affiliate boards related to 121 SW Salmon's purchase of the WTC, including in the list the date of each presentation, and provide copies of all presentation materials for each presentation.

Response:

Presentations made to PGE and PGE affiliate boards related to the purchase of the WTC by 121 SW Salmon are provided in attachments 004-A through 004-D.

Attachments 004-A through 004-D are protected information and subject to Protective Order 18-261.

UI 405

Attachment 004-D

Provided in Electronic Format only

Protected Information Subject to Protective Order 18-261

PGE Finance Committee Presentation and Draft Resolutions
April 24, 2018

Pages 42 - 51 of Exhibit/701 contain Protected Information Subject to Modified General Protective Order and have been redacted in their entirety.

July 6, 2018

TO: Lance Kaufman
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UI 405
PGE Response to OPUC Information Request No. 005
Dated June 22, 2018

Request:

Please provide all due diligence studies related to 121 SW Salmon's purchase of the WTC.

Response:

The due diligence studies and a description of the studies related to 121 SW Salmon's purchase of the WTC are provided in attachments 005-A through 005-F.

Attachments 005-A through 005-F are protected information and subject to Protective Order 18-261.

UI 405

Attachment 005-F

Provided in Electronic Format only

Protected Information Subject to Protective Order 18-261

Value

Pages 54 - 68 of Exhibit/701 contain Protected Information Subject to Modified General Protective Order and have been redacted in their entirety.

July 6, 2018

TO: Lance Kaufman
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UI 405
PGE Response to OPUC Information Request No. 009
Dated June 22, 2018

Request:

Are the cost impacts of 121 SW Salmon's purchase of WTC included in PGE's current rate case Docket No. UE 335? If yes, please explain how. If no, please explain why not.

Response:

No. PGE has not included any cost impacts from 121 Salmon's purchase of the World Trade Center (WTC) in the UE 335 general rate case for two reasons:

- The purchase transaction is not expected to be complete until November 2018, prior to which PGE will require Commission approval of the new lease agreement in this proceeding (UI 405).
- The transaction would have no impact on PGE's 2019 forecasted costs because the new rental agreement would maintain the same rental cost as the prior rental agreement for PGE.

July 6, 2018

TO: Lance Kaufman
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UI 405
PGE Response to OPUC Information Request No. 010
Dated June 22, 2018

Request:

Please provide all analysis performed by PGE to ensure that the rental rate in the lease is at or below the cost of owning and operating the property.

Response:

Attachment 010-A provides the analysis of the rental rates versus the cost of owning the property. The amount in cell D6 represents the levelized cost of owning the property, which is higher than the $2.5 million annual rent for the WTC. Operating costs are not included as part of this analysis because PGE would incur the same operating costs regardless of whether the building is leased or owned.

Attachment 010-A is protected information and subject to Protective Order 18-261.

UI 405

Attachment 010-A

Provided in Electronic Format only

Protected Information Subject to Protective Order 18-261

Theoretical Principal and Interest Payments

Page 72 of Exhibit/701 contains Protected Information Subject to Modified General Protective Order and have been redacted in their entirety.

July 6, 2018

TO: Lance Kaufman
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UI 405
PGE Response to OPUC Information Request No. 011
Dated June 22, 2018

Request:

Please confirm whether PGE has ever previously owned the WTC. If it has not, please explain PGE's understanding of the history of the ownership of the WTC. If it has, please explain the WTC's ownership history and include in your explanation all reasons for PGE's past divestiture of the WTC.

Response:

PGE acquired the property upon which the World Trade Center (WTC) is now located (generally Blocks 5, 6 and 12, CITY OF PORTLAND, Portland, Multnomah County, Oregon) from US National Bank on November 17, 1975. The WTC property was conveyed by PGE to 121 SW Salmon the same day. The three buildings comprising the WTC were constructed by 121 SW Salmon thereafter.

In March 1977, 121 SW Salmon Street Corporation obtained financing from Travelers Insurance Company using the WTC as security. PGE guaranteed the obligations of 121 SW Salmon with respect to the Travelers financing. The proceeds of the loan were used to enable PGE to redeploy capital to its core business functions including the expansion of its generation capacity such as the Trojan Nuclear Facility.

In September 1978, 121 SW Salmon Street Corporation sold WTC to American Leased Premises Investors VIII ("API"), a California Limited Partnership, subject to the existing mortgage in favor of Travelers Insurance Company, which was assumed and eventually satisfied by API and 121 SW Salmon then rented the WTC back from API pursuant to a lease dated September 11, 1978. PGE guaranteed the obligations of 121 SW Salmon to API under the lease. At no time was the WTC included in PGE retail rates.

July 6, 2018

TO: Lance Kaufman
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UI 405
PGE Response to OPUC Information Request No. 012
Dated June 22, 2018

Request:

Please provide the current lease agreement between 121 SW Salmon and the current owner(s) of the WTC.

Response:

Attachment 012-A provides a copy of the current lease agreement between 121 SW Salmon Street Corporation and the owner of the WTC (currently IEH Portland LLC) dated September 11, 1978. Attachment 012-B provides the first amendment to the lease, effective December 5, 1997. Attachment 012-C provides the related sublease agreement 121 Salmon Street Corporation and Portland General Electric Corporation.

Attachments 012-A through Attachment 012-C are protected information and subject to Protective Order 18-261

UI 405

Attachment 012-C

Provided in Electronic Format only

Protected Information Subject to Protective Order 18-261

121 SW Salmon Sublease Agreement

Pages 76 - 78 of Exhibit/701 contain Protected Information Subject to Modified General Protective Order and have been redacted in their entirety.

September 10, 2021

To: Jesse O. Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to AWEC Data Request 076
Dated August 27, 2021

Request:

Please refer to PGE's response to AWEC DR 14. Does PGE agree that if energy efficiency savings are consistent from year to year over the entire period of historic data used to forecast energy, the impact of energy efficiency trends will be embedded within the base forecast model? If no, why not?

Response:

In response to AWEC Data Request No. 014, PGE described its reasoning behind the assumptions made in the load forecast which adjusts for incremental savings associated with SB 838 but not with SB 1149.

There is not a clear line to define what is and what is not embedded within the base forecast model. If energy efficiency savings were consistent year over year in the historic period and the forecast period, it would be reasonable to assume the trend was embedded within the forecast model. However, the forecasted energy efficiency savings associated with SB 838 are not consistent year over year in either period, so PGE has assumed the savings are not embedded.

September 10, 2021

To: Jesse O. Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to AWEC Data Request 079
Dated August 27, 2021

Request:

Please provide the total lease expense included in the test year for the WTC.

Response:

The total World Trade Center (WTC) rent expense included in PGE's 2022 general rate case is \$5,683,069.[1] This does not include amounts allocated to non-utility accounts, construction work in progress (CWIP) accounts, or amounts allocated to non-PGE tenants. The total WTC rent PGE is forecast to incur for 2022 is \$6,164,518.

[1] This amount includes PGE's proportionate share of expenses for operating and maintaining the WTC complex.

September 10, 2021

To: Jesse O. Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to AWEC Data Request 080
Dated August 27, 2021

Request:

Please provide the total square feet leased by PGE for the WTC from 2015 to present.

Response:

The following table provides the requested information.

Year	2015	2016	2017	2018	2019	2020	2021 (Budget)	2022 (Forecast)
PGE Leased Ft^2	352,388	333,436	336,896	336,891	336,151	331,363	317,778	232,636

September 27, 2021

To: Nadine Hanhan
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Confidential Data Request 657
Dated September 13, 2021

Request:

[redacted]

Response:

Confidential Attachment 657-A provides the project justification form P36501. Confidential Attachment 657-B provides change order(s) associated with final purchase order amounts that exceed $750,000.

Attachments 657-A and 657-B contain protected information and are subject to General Protective Order No. 21-206.

Pages 83 - 89 of Exhibit/701 contain Protected Information Subject to Modified General Protective Order and have been redacted in their entirety.