BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PACIFICORP d/b/a PACIFIC POWER & LIGHT COMPANY, Respondent.	Docket No. UE-230172 (Consolidated)
In the Matter of ALLIANCE OF WESTERN ENERGY CONSUMERS' Petition for Order Approving Deferral of Increased Fly Ash Revenues	Docket No. UE-210852 (Consolidated)

PACIFIC POWER'S POST-HEARING BRIEF

January 12, 2024

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I. INTRODUCTION

1. In accordance with the May 24, 2023, Prehearing Conference Order, PacifiCorp dba Pacific Power & Light Company (PacifiCorp or the Company) submits this Post-Hearing Brief to the Washington Utilities and Transportation Commission (Commission). This brief is limited to only the net power cost (NPC) and power cost adjustment mechanism (PCAM) issues that were not resolved by the Settlement Stipulation filed on December 15, 2023.

2. The Company forecasts $2.555 billion for total-company net power costs (NPC) in 2024, with $199 million allocated to Washington.[1] This estimate is based on historical actual NPC, forecasted to calendar year 2024. Consistent with Commission precedent and the Company's 2021 Power Cost Only Rate Case (PCORC), the Company proposes a compliance filing NPC update following the Commission's final order but before the rate effective date for Rate Year 1 of the proposed multi-year rate plan (MYRP).[2] This update will be calculated in the same manner as the baseline that was used to derive the revenue requirement for this case, updated for the most recent Official Forward Price Curve (OFPC) and the Company's electric and gas hedging and contract positions as of the latest OFPC date.[3]

[1] Mitchell, Exh. RJM-1CTr at 6:20-21.
[2] *WUTC v. Pac. Power & Light Co.*, Dockets UE-140762, UE-140617, UE-131384, & UE-140094 (consolidated), Order 07 at ¶ 4 (Dec. 5, 2014) ("the Commission has 'routinely . . . allowed, and even required, power cost updates related to changes in fuel supply costs late in general rate proceedings, *even at the compliance stage*.") (emphasis added).
[3] Mitchell, Exh. RJM-1CTr at 38:2-11. The specific hedging contracts that will be included in the update are wholesale electric sale and purchase contracts that are for long-term firm sales and purchases (including long-term power purchase agreements), short-term firm sales and purchases, and natural gas sales and purchase contracts.

3. The update for Rate Year 1 will also incorporate all the adjustments recommended by Staff in its response testimony.[4] In addition, the Company will remove the impacts of the federal Ozone Transport Rule (OTR).[5] The Company will also incorporate several corrections and updates identified in its rebuttal testimony.[6] Together, the Company's illustrative update including these accepted adjustments, updates, and corrections reduced power costs by $8.8 million Washington-allocated, which amounts to a revenue requirement reduction of approximately $9.2 million.[7]

4. For Rate Year 2, the Company proposes to update NPC on January 31, 2025.[8] The second-year update will be calculated in the same manner as the baseline NPC for Rate Year 1, updated for the most recent OFPC and the Company's electric and gas hedging and contract positions as of the latest OFPC date.

5. There are only six NPC issues that remain in dispute:

- Staff and the Alliance of Western Energy Consumers (AWEC) recommend that the Company use the rate year, as opposed to the calendar year, to forecast NPC.[9] Adopting this adjustment, however, violates the matching principle because all other revenue requirement items are forecast using calendar years. The result is that customers receive NPC benefits without paying the matching costs incurred to produce those benefits. Moreover, while using Rate Year 1 to forecast NPC reduces rates for the first year, that decrease is more than offset in Rate Year 2, creating overall higher rates for Washington customers.

[4] Mitchell, Exh. RJM-3CT at 4:6-5:1.
[5] Rao, Exh. EVRR-1T at 4:6-7.
[6] Mitchell, Exh. RJM-3CT at 14:10-23:9.
[7] Cheung, Exh. SLC-8T at 25:17-19.
[8] Mitchell, Exh. RJM-1CTr at 2:17-18.
[9] Joint Issues Matrix at 7-8.

- AWEC's recommendation to use gas generation to close the open position created by the Washington Interjurisdictional Allocation Methodology (WIJAM) fails to account for reserve and transmission requirements, thereby selectively taking gas generation to serve Washington without accounting for the offsetting costs incurred to take that generation. AWEC's modeling also contains errors that when corrected significantly increase Washington-allocated NPC.
- AWEC recommends removing market capacity limits (market caps) from three hubs in the Aurora model to enable more off-system sales.[10] AWEC's recommendation not only *increases* NPC, but it is also contrary to the undisputed trend in declining off-system sales in recent years.
- AWEC selectively objects to only one NPC correction the Company identified in its rebuttal testimony—the correction to the Day Ahead and Real Time (DA/RT) Volume Component.[11] Without the correction, the DA/RT adjustment imputed revenue that was more than ten times higher than any historical level of arbitrage revenue received by the Company. Correcting the error imputes reasonable arbitrage revenues into the NPC forecast based on historical actual results. To the extent AWEC's objection to the DA/RT correction is based on the fact the Company proposed the correction in rebuttal, all the Company's rebuttal updates and corrections should be removed from the NPC forecast, which increases Washington-allocated NPC.
- AWEC disputes the Company's updated fuel costs for the Jim Bridger coal-fired plant (Bridger), which include Bridger Coal Company (BCC) reclamation and

[10] Joint Issues Matrix at 9.
[11] Joint Issues Matrix at 10.

depreciation expenses that are not otherwise recovered through the balancing account approved by the Commission in the Company's last general rate case, docket UE-191024 (2020 rate case).[12] AWEC supports the Company's proposal to include the Bridger's coal units in Washington rates through 2025,[13] which necessitates the updated reclamation and depreciation costs.

- AWEC raised an entirely new adjustment at hearing, suggesting that the NPC forecast should impute incremental wheeling revenue associated with the Gateway South transmission line.[14] Not only is this adjustment procedurally improper and entirely without evidentiary support, it ignores the fact that (1) wheeling revenue is not included in NPC; (2) the NPC forecast includes the NPC benefits of Gateway South; and (3) the base rates include a pro forma wheeling revenue adjustment for 2024 and 2025, in part, to account for new transmission investments, including Gateway South.

6. The Company also recommends the Commission modify the PCAM to eliminate the deadbands and sharing bands, or, in the alternative, adopt Staff's recommendation to replace the current deadbands and sharing bands with a single 90/10 sharing band.[15] Since the Commission approved the current PCAM in 2015, circumstances have changed. First, increased market volatility and renewable generation make forecasting an accurate NPC baseline more difficult, which increases the likelihood of NPC variances. Second, actual experience with the PCAM has demonstrated that it is inequitable and that customers would have been better off without the deadbands and sharing bands. Third,

[12] Joint Issues Matrix at 13.
[13] Joint Issues Matrix at 7.
[14] Pepple, TR. 89:20-24.
[15] Joint Issues Matrix at 24.

the Company has a strong incentive to control and minimize its actual NPC regardless of the structure of the PCAM, although many NPC drivers, like market prices and weather, are outside the Company's control. Fourth, removing the deadbands and sharing bands, or adopting Staff's recommended 90/10 sharing bands, will align the Company's PCAM with the majority of comparable mechanisms across the country.

7. Staff recommended its 90/10 proposal—which the Company supports—based on its conclusions that the current PCAM is inequitable, not optimal, unnecessarily complicated, and has resulted in customer "losses" when actual power costs were lower than forecast power costs. Staff also concluded that the key drivers of power cost variances, like deviations in load, renewable resource generation, and market prices are outside PacifiCorp's control and that increased renewable generation will increase power cost variability.[16] For these reasons, the Commission should approve a modification to the PCAM in this case to align with either the Company's primary recommendation to eliminate the deadbands and sharing bands or adopt Staff's 90/10 sharing bands.

II. NET POWER COSTS

A. The NPC forecast must be based on calendar years to align with all other revenue requirement items and adhere to the matching principle.

8. The Company's NPC forecast is based on calendar year 2024 for Rate Year 1 and 2025 for Rate Year 2. Using calendar years aligns the NPC forecast with the forecast used for all other revenue requirement items, including the capital costs for generation and transmission resources used to derive the NPC forecast.[17] AWEC recommends moving the NPC forecast period for Rate Year 1 to the twelve months ending February

[16] Wilson, Exh. JDW-1CT at 35:13, 27:1-7, and 24 (Table 3).
[17] Cheung, Exh. SLC-8T at 68:19-21.

2025, and Staff recommends moving the NPC forecast period for Rate Year 1 to the twelve months ending March 2025, both intending to align the NPC forecast with the rate effective period.[18] At hearing, AWEC recommended using calendar year 2025 for Rate Year 2, while Staff appears to support using the same forecast period for Rate Year 2, which would be the twelve months ending March 2026.[19]

9. Moving *only* the NPC forecast forward creates a mismatch with all other revenue requirement elements that will continue to be forecast on a calendar-year basis.[20] This mismatch is contrary to well-established Commission precedent requiring that all "cost of service components—revenue, investment, expenses, and cost of capital—must be considered and evaluated at a similar point in time."[21] Moreover, shifting the NPC test period provides no overall customer benefits—the reduction in Rate Year 1 is entirely offset by the increase in Rate Year 2.[22] Using multiple test periods for NPC and all other revenue requirement items also complicates the MYRP plan process, which will rely on calendar year Commission Basis Reports.[23] The Company's proposed NPC forecast period is therefore reasonable and should be approved.

1. The Company's approach is consistent with the matching principle.

10. "Under the matching principle, all cost of service components—revenue, investment, expenses, and cost of capital—must be considered and evaluated at a similar

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[18] Mullins, Exh. BGM-1CT at 20:22-21:2; Wilson, Exh. JDW-24T 3:23-4:3, 6:9-11.
[19] Pepple, TR. 89:13-16.
[20] Cheung, Exh. SLC-8T at 68:15-21.
[21] *WUTC v. PacifiCorp d/b/a Pacific Power & Light Co.*, Dockets UE-050684 and UE-050412, Order 04/03 at ¶ 194 (Apr. 17, 2006) (quoting *WUTC v. Avista Corp.*, Dockets UE-050482 and UG-050483, Order 05 at ¶ 111 (Dec. 21, 2005); *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-090704 and UG-090705 (consolidated), Order 11 at ¶ 27 (Apr. 2, 2010) ("The matching principle requires that all factors affecting a proposed pro forma change be considered in determining the pro forma level of expense.").
[22] *See* Exh. RJM-8X at 1.
[23] Cheung, Exh. SLC-8T at 69:2-9.

point in time."[24] This matching requires "consideration of offsetting factors" that "may 'cancel out' or at least mitigate the impact of a known and measurable increase in expense."[25] "If offsetting factors are not taken into account, the known and measurable change will result in overstated or understated revenue requirements" because "a mismatch in the relationship of revenues, expenses, and rate base is created."[26] The Commission's Used and Useful Policy Statement affirmed "the Commission's longstanding practice" that "proposed pro forma adjustments to test year amounts . . . adhere to the matching principle (*i.e.*, the principle that costs should be matched to offsetting factors)."[27]

11. When setting baseline NPC, the Commission has emphasized the importance of matching the cost of resources with the NPC benefits produced by those resources.[28] In

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[24] Dockets UE-050684 and UE-050412, Order 04/03 at ¶ 194 (internal quotations omitted).

[25] Dockets UE-090704 and UG-090705 (consolidated), Order 11 at ¶ 27; *see also WUTC v. Avista Corporation d/b/a Avista Utilities*, Dockets UE-090134, UG-090135, UG-060518 (consolidated), Order 10 at ¶ 46 (Dec. 22, 2009) ("Offsetting factors, as the term suggests, diminish the impact of the known and measurable event. A mismatch would be created if offsetting factors are not taken into account. That is, the known and measurable change will be overstated or understated, distorting the test year relationships among revenues, expenses, and rate base.").

[26] Dockets UE-090704 and UG-090705 (consolidated), Order 11 at ¶ 27; *see also In the Matter of the Commission Inquiry into the Valuation of Public Service Company Property that Becomes Used and Useful after Rate Effective Date*, Docket U-190531, Policy Statement on Property That Becomes Used and Useful after Rate Effective Date at ¶ 24 (Jan. 31, 2020) ("The Commission's longstanding practice of using the matching principle continues to require netting of known and measurable changes with any offsetting factors that diminish the impact of the known and measurable event. Including post-test-year plant in rates without considering these offsetting factors creates a mismatch that overstates the effect of the known and measurable event, thus distorting the rate-year relationship among revenues, expenses, and rate base.") (internal footnotes omitted).

[27] Docket U-190531, Policy Statement on Property That Becomes Used and Useful after Rate Effective Date at ¶ 20; *see also id.* at paragraph 22 ("WAC 480-07-510(3)(c)(ii), which defines pro forma adjustments, remains unchanged, applicable, and relevant. In particular, this rule defines the known and measurable standard and the offsetting factors standard, both of which are elements of the matching principle, and both of which are necessary to ensure that costs and offsetting benefits are accounted for during the period in which they occur.").

[28] Dockets UE-090134, UG-090135, UG-060518 (consolidated), Order 10 at ¶ 49 ("Power cost models yield expected net power costs by rigorously matching costs and revenues."); *see also* Dockets UE-090704 and UG-090705 (consolidated), Order 11 at ¶ 153 (when rejecting an NPC adjustment, the Commission noted that the "Company is correct to argue the importance of matching all costs, benefits, and other factors when rates are adjusted.").

the Company's 2015 rate case, "[i]n keeping with the Commission's long-standing principle of benefits following burden," the Commission disallowed recovery of certain costs associated with a transmission asset exchange with Idaho Power because the NPC benefits of the exchanged assets were not included in rates.[29] Similarly, when approving cost recovery for a wind resource coming into service far from the end of the historical test period, the Commission noted it was "less concerned that this might result in a mismatch of costs and revenues because the assets at issue are generation assets, the benefits of which are matched to a significant degree via the power cost and production factor adjustments."[30]

12. Here, the Company's NPC forecast using calendar year 2024 is the same as the forecast period for all other revenue requirement items, consistent with the matching principle.[31] For example, this case includes several significant transmission and wind generation resources that reduce NPC and will be placed in service during 2024, including the Gateway South and Gateway West Segment D.1 transmission projects, and the Rock Creek I wind resource, and Rock River wind repowering project. The capital costs of these resources reflect their in-service dates, i.e., because Rock Creek I and Rock River will be placed in-service in December 2024, customer rates essentially reflect one-twelfth of the capital costs of these wind resources.[32] The NPC benefits produced by these resources should also reflect the same one-twelfth of the annual benefits of the resources to match the capital costs included in the revenue requirement. The Company's

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[29] *WUTC v. Pacific Power & Light Company, a Division of PacifiCorp*, Docket UE-152253, Order 12 at ¶ 216 (Sept. 1, 2016).
[30] Dockets UE-090704 and UG-090705 (consolidated), Order 11 at ¶ 232.
[31] Cheung, Exh. SLC-8T at 68:19-21.
[32] *See* McGraw, Exh. RDM-1CTr at 5:3-4 (Rock Creek I in-service in December 2024); Hemstreet, Exh. TJH-1CTr at 12:21-23 (Rock River repowering in-service in November 2024).

calendar year NPC test period achieves this matching and ensures that customers pay for the NPC benefits they receive.

2. Staff and AWEC take NPC benefits without paying the costs incurred to generate those benefits.

13. While the Commission's application of the matching principle has typically focused on whether to include capital investments in rate base without considering offsetting factors (like lower NPC), the opposite is implicated here. In this case, Staff and AWEC do not dispute the capital investments in transmission and wind resources. However, by seeking to move the NPC forecast period forward to capture several months in 2025—in part to explicitly capture more wind benefits[33]—Staff and AWEC are taking several additional months of NPC benefits without a corresponding increase to the capital costs incurred to generate those additional NPC benefits. Staff and AWEC therefore violate the matching principle by ignoring offsetting factors in the form of higher capital costs incurred to generate the NPC benefits they seek in Rate Year 1.[34]

14. Moreover, the mismatch created by AWEC and Staff is significant. For Rate Year 1, the wind and transmission rate base for calendar year 2024 is *$40 million lower* than the rate base for the same resources if rate base were calculated using the rate year.[35] This means that Staff and AWEC would take the NPC benefits of this $40 million rate base investment without paying for it, in clear violation of the "Commission's long-standing principle of benefits following burden[.]"[36]

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[33] Mullins, Exh. BGM-1CT at 20:15-18; Wilson, Exh. JDW-24T at 5:4-6.
[34] Dockets UE-090704 and UG-090705 (consolidated), Order 11 at ¶ 27; Policy Statement on Property That Becomes Used and Useful after Rate Effective Date at ¶ 24.
[35] Cheung, Exh. SLC-8T at 71 (Table 6). For rate year two, the rate base mismatch is $11 million. *Id.*
[36] Docket UE-152253, Order 12 at ¶ 216.

3. Shifting the NPC forecast does not produce customer benefits.

15. Staff's and AWEC's primary rationale for shifting the NPC forecast is to remove the outage related to the gas conversion of Bridger Units 1 and 2 from the NPC forecast.[37] While it is true that shifting the Rate Year 1 forecast to remove the outage decreases the NPC forecast by roughly $5 million, the same shift in NPC forecast for Rate Year 2 increases the NPC forecast by roughly the same amount due to the removal of coal generation from the rate year months extending into 2026.[38] In total, shifting the NPC forecast period increases Washington-allocated NPC.[39]

16. To avoid the rate increase associated with the removal of coal from Rate Year 2, at hearing AWEC argued that the Rate Year 2 NPC forecast should be based on calendar year 2025, meaning it would overlap with Rate Year 1 and undermine any credible argument that the NPC forecast must align with the rate effective period.[40] Consistency requires that both NPC forecasts use the same test period—either calendar years to match all other revenue requirement items or the rate effective period, in which case a reduction in Rate Year 1 is offset by an increase in Rate Year 2.

4. A calendar year NPC forecast is necessary to implement the MYRP.

17. The Company modeled all revenue requirement, including NPC, on a calendar year basis to better facilitate subsequent filing requirements necessary to implement the MYRP.[41] Specifically, the Company proposes using its Commission Basis Reports as part of the provisional capital review process.[42] Because the Company prepares its

[37] Mullins, Exh. BGM-1CT at 20:4-12; Wilson, Exh. JDW-24T at 4:14-18.
[38] Mitchell, Exh. RJM-3CT at 6:8-7:2.
[39] Exh. RJM-8X at 1-2.
[40] Pepple, TR. 89:13-16.
[41] Cheung, Exh. SLC-8T at 69:2-4; Exh. RJM-8X at 1.
[42] Cheung, Exh. SLC-8T at 69:4-6; Exh. RJM-8X at 1.

Commission Basis Reports on a calendar year basis, synchronizing rates assumptions to a calendar year basis will better support the subsequent reporting processes.[43]

5. The Company's approach is lawful and consistent with the 2021 PCORC.

18. Neither AWEC nor Staff can credibly argue that the Company's recommended NPC test year is contrary to Commission precedent or unlawful. Staff argues that WAC 480-07-510(3)(c)(ii) requires that the NPC forecast must be based on the test year or on the future rate year.[44] However, in the Company's 2021 PCORC, the Company entered into a stipulation, which was joined by Staff, where "NPC baseline [was] based on a 12-month period (January to December 2022) that does not precisely align with the rate year (May 2022 to April 2023)."[45] Over AWEC's objection to the use of a calendar year forecast, rather than the rate effective period, the Commission approved the use of the calendar year forecast after concluding that it was lawful and in the public interest.[46] And at hearing in this docket, AWEC argued that the NPC forecast for Rate Year 2 should be based calendar year 2025, to avoid NPC increase associated with removing coal from rates in 2026.[47] If it is lawful to use a calendar year forecast for Rate Year 2, it is equally lawful to use a calendar year forecast for Rate Year 1. Arguments that the use of a

[43] Cheung, Exh. SLC-8T at 69:6-9; *see also* RCW 80.28.425(6) (requiring use of Commission Basis Reports for MYRP earnings reviews).
[44] Wilson, Exh. JDW-24T at 5:10-13; WAC 480-07-510(3)(c)(ii) ("Pro forma adjustments give effect for the test period to all known and measurable changes that are not offset by other factors. The company and any other party filing testimony and exhibits proposing pro forma adjustments must identify dollar values and underlying reasons for each proposed pro forma adjustment. Pro forma adjustments must be calculated based on the restated operating results. Pro forma fixed and variable power costs, net of power sales, may be calculated directly based either on test year normalized demand and energy load, or on the future rate year demand and energy load factored back to test year loads.")
[45] *WUTC v. PacifiCorp d/b/a Pacific Power & Light Co.*, Docket UE-210402, Order 06 at ¶ 137-38 (Mar. 29, 2022) ("We therefore reject AWEC's arguments that the Settlement's power cost update departs from Commission practice or that the Company's modeling is somehow unreliable.").
[46] Docket UE-210402, Order 06 at ¶ 137.
[47] Pepple, TR. 89:9-19.

calendar year forecast is inconsistent with the Commission's rules or otherwise unlawful are therefore without merit.

6. The Company's NPC forecast will be based on up-to-date information.

19. Staff argues that the NPC forecast should be based on the most up-to-date information, implying that the use of a calendar year forecast does not meet this standard.[48] To the contrary, the Company's proposal would update the NPC after the Commission's final order and before the rate effective date, just like the Staff and AWEC proposal. The only difference is the forecast period, not the vintage of the data.[49]

B. AWEC's Washington Balancing Adjustment is incomplete.

20. The WIJAM was part of a multi-party stipulation submitted in the Company's 2020 rate case.[50] Under the WIJAM, the resources allocated to Washington provide insufficient energy to serve Washington load, which creates an inherent energy deficit. When the WIJAM was approved in the Company's 2020 rate case, the Company explained that the energy deficit is resolved using modeled market transactions—either through a reduction in market sales or an increase in market purchases.[51] The use of market transactions is reasonable notwithstanding the fact that the Company's ability to make off-system sales is declining (as discussed below) because the approved methodology either reduces sales or increases *purchases*, which are not subject to the same liquidity issues discussed below in the context of market caps.[52]

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[48] Joint Issues Matrix at 7.
[49] Docket UE-210402, Order 06 at ¶ 137; *see also id.* at ¶ 106 (agreeing that the NPC baseline "should be set as closely as possible to costs that are reasonably expected to be actually incurred during short and intermediate periods following the conclusion of such proceedings").
[50] *See WUTC v. PacifiCorp, dba Pacific Power & Light Co.*, Docket UE-191024 *et al.*, Settlement Stipulation at ¶ 24 (July 20, 2020).
[51] Mitchell, Exh. RJM-3CT at 8:10-13.
[52] Mitchell, TR 160:16-22.

21. The use of market transactions to close Washington's open position was used without controversy in the 2020 rate case and the 2021 PCORC. In this case, however, AWEC recommends replacing a portion of increased market purchases with modeled gas generation from gas plants allocated to Washington.[53] AWEC's adjustment is flawed, however, because it fails to account for offsetting impacts of modeling increased gas generation for Washington customers.

1. AWEC ignores reserve requirements.

22. The WIJAM recognizes the Company operates its system on an integrated basis and the Company does not dispatch specific resources to serve individual states or hold reserves on specific resources to serve individual states.[54] Based on this fact, the WIJAM allocation starts with a simulation that models total-system dispatch and then allocates costs to Washington based on only those resources included in Washington rates.[55]

23. The WIJAM nearly doubled the nameplate capacity of wind resources allocated to Washington, in order to accommodate Washington's Clean Energy Transformation Act (CETA).[56] The increased allocation of intermittent generation to Washington, however, also increased the reserve requirements necessary to integrate that intermittent generation for Washington customers.[57] Because the WIJAM starts with a total-system model, Washington customers receive the benefit of reserves held on coal and natural gas units that are not allocated to Washington, i.e., Washington NPC modeling does not assume that the limited coal and gas units allocated to Washington are holding reserves for all the

[53] Mullins, Exh. BGM-1CT at 38:20-39:6.
[54] Mitchell, Exh. RJM-3CT at 9:7-16.
[55] Mitchell, Exh. RJM-3CT at 9:13-16.
[56] Mitchell, Exh. RJM-3CT at 10:12-13.
[57] Mitchell, Exh. RJM-3CT at 10:14-15.

intermittent generation allocated to Washington.[58] AWEC's adjustment relies on unused capacity at Washington-allocated gas plants.[59] But that capacity is unused, in part, because the gas generation is not holding Washington-specific reserves. If the reserves necessary to serve Washington with increasing intermittent generation are held only on generation allocated to Washington, then Washington NPC will increase by approximately $20 million.[60]

24. Given these facts, to implement AWEC's recommendation first requires establishing what portion of the Washington-allocated gas generation is unused, which requires the Company to model NPC as if the gas generation allocated to Washington is dispatched uniquely to serve Washington.[61] If gas generation is going to be uniquely dispatched to serve Washington, then the intermittent renewable generation must also be uniquely dispatched to serve Washington to determine if, in fact, there is unused gas capacity available to close the WIJAM's open position after accounting for the reserve requirements of Washington-allocated intermittent generation. Without this step, there is a mismatch where Washington is taking the benefits of gas generation dispatch while shifting reserves onto coal and gas units that are not allocated to Washington. This means that to fairly represent AWEC's adjustment would require a fundamental change to the WIJAM to create a Washington-only dispatch scenario using only those resources allocated to Washington under the WIJAM, which would increase Washington-allocated NPC by $20 million for reserves alone. AWEC, however, ignores the broader complexities created by its recommendation and therefore its proposal is incomplete.

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[58] Mitchell, Exh. RJM-3CT at 10:21-11:6.
[59] Mullins, Exh. BGM-1CT at 39:1-6.
[60] Mitchell, Exh. RJM-3CT at 11:7-13.
[61] Mitchell, Exh. RJM-3CT at 11:21-12:3.

2. AWEC ignores transmission requirements.

25. In addition to ignoring reserve requirements, AWEC's recommendation fails to account for the fact that modeling increased dispatch of gas generation to serve Washington must ensure sufficient transmission capacity to wheel the gas generation to Washington load.[62] AWEC claims its adjustment is focused only on unused gas capacity that is not generating or holding reserves.[63] But unused capacity can also result from lack of transmission capacity.[64] To ensure sufficient transmission to accommodate AWEC's proposal would require the Company to dispatch down resources not allocated to Washington to free up transmission capacity.[65] This means that Washington would now be relying on the dispatch of non-Washington-allocated resources to serve Washington, which is contrary to the principles underlying the WIJAM. Moreover, AWEC failed to provide the necessary evidence in the record to meet the Commission's standard for modifying a cost allocation methodology to include such additional cost from non-Washington-allocated resources.[66]

3. AWEC's adjustment contains errors that, when corrected, increase NPC.

26. Setting aside the conceptual flaws in AWEC's recommendation, AWEC's modeling is erroneous and correcting its methodology produces an *increase* to

[62] Mitchell, Exh. RJM-3CT at 11:15-20.
[63] Mullins, Exh. BGM-1CT at 38:20-39:6.
[64] Mitchell, Exh. RJM-3CT at 11:15-20.
[65] Mitchell, Exh. RJM-3CT at 11:21-12:1.
[66] *See* Docket UE-191024 et al., Final Order 09/07/12 at ¶ 95 (Dec. 14, 2020) ("The Commission has long held that only resources that are used and useful for service to Washington may be included in rates. This standard, which forms the basis for the current WCA methodology, may be met only when a utility demonstrates that its resource provides quantifiable direct or indirect benefits to Washington commensurate with its cost.") (internal quotation marks omitted).

Washington-allocated NPC. First, AWEC claims its adjustment uses hourly loads, but actually relies on monthly average generation to calculate the NPC impact.[67]

27. Second, AWEC calculates the weightings between purchase and sale prices using monthly instead of hourly averages, despite its recommendation to use hourly data.[68]

28. Third, AWEC's monthly generation is taken from the Aurora model that has different purchase and sales prices as a result of implementing the DA/RT adjustment.[69] When calculating its WIJAM adjustment outside of Aurora, however, AWEC valued generation using market prices that are ***not*** an input to the Aurora model to re-dispatch gas generation that is an output of the Aurora model, and then AWEC collapsed purchase and sales prices into one. Taken together, this methodology produces invalid results.

29. Fourth, AWEC ignores fuel startup costs when increasing gas dispatch, which produced lower-than-forecast costs to calculate the NPC impact.[70]

30. Fifth, AWEC mixed and matched inputs come from at least two different modeling sensitivities, making the results unreliable.[71]

31. Sixth, AWEC incorrectly ignores the fact that Climate Commitment Act allowance costs are modeled as part of the Chehalis dispatch cost and then the Company offsets the allowance costs with no-cost allowances.[72]

32. AWEC did not dispute any of these errors at hearing. When these errors are corrected, Washington-allocated NPC increases by approximately $41 million.[73]

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[67] Mullins, Exh. BGM-1CT at 39:15-16; Mitchell, Exh. RJM-3CT at 12:13-15.
[68] Mullins, Exh. BGM-1CT at 39:17-19; Mitchell, Exh. RJM-3CT at 12:16-18.
[69] Mitchell, Exh. RJM-3CT at 12:19-24.
[70] Mitchell, Exh. RJM-3CT at 13:1-2.
[71] Mitchell, Exh. RJM-3CT at 13:3-5.
[72] Mitchell, Exh. RJM-3CT at 13:6-11.
[73] Mitchell, Exh. RJM-3CT at 13:13.

C. The Company's imposition of market caps at all trading hubs accurately reflects current market dynamics and lack of liquidity across the West.

1. Market caps accurately reflect real-world market illiquidity.

33. Market caps are parameters included in Aurora to simulate real-world conditions by placing limitations on the Company's ability to make bilateral sales at illiquid market hubs.[74] For many years, the Company imposed limits on the ability of the Generation and Regulation Initiative Decision Tools (GRID) model to sell at various market hubs. These market caps attempted to ensure that GRID produced off-system sales levels that were generally consistent with what could be achieved in actual operations. With the transition to Aurora, the Company carried over the same market cap methodology because, like GRID, Aurora produces unreasonable levels of off-system sales without market caps.[75] In the 2021 PCORC, the Company imposed market caps on all market hubs,[76] which reflects the fact that the Company's off-system sales volumes have been steadily decreasing in recent years, consistent with the general trend across the West.[77] Accordingly, including market caps in the model is consistent with prior practice and aligns with the Commission's objective of determining "with the greatest degree of precision that forward looking models can produce, an accurate estimate of actual costs that [the utility] will experience in the near and intermediate terms."[78]

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[74] Zachariah, Exh. IMRZ-1CT at 4:18-21.
[75] *Id.* at 1:19-2:3.
[76] *Id.* at 2:3-6.
[77] *Id.* at 5:3-6.
[78] Docket UE-210402, Order 06 at ¶ 124.

2. Declining bilateral transactions across the West support market caps at all hubs.

34. Market caps are designed to model transactional constraints that exist at illiquid market hubs in actual operation.[79] Today, as a result of evolving market dynamics, there are no market hubs that the Company considers liquid.[80] A liquid market is a market where the Company is able to find a buyer to take its excess energy at or above cost at almost all hours of almost all days.[81] The volume of Company sales have been in constant decline for over five years, and energy shortfalls have increased across the region.[82] The Company is not unique in this regard; the volume of transactions in regional, bilateral wholesale markets has steadily declined in recent years.[83] The limited availability of sales opportunities is further evidenced by the increased magnitude of energy emergency alert (EEA) events—the average duration of EEAs in 2022 was nearly double the average duration of EEAs in previous years.[84]

35. The Company's declining ability to make off-system sales is driven by two developments. First, the Energy Imbalance Market (EIM) has dramatically changed how utilities throughout the West transact in the bilateral markets. Utilities that historically would have transacted in the day-ahead and hour-ahead markets are instead transacting in the intra-hour EIM. Aurora does not model the EIM; those benefits are imputed as a reduction to NPC outside the model. Therefore, as EIM transactions increase, bilateral

[79] Zachariah, Exh. IMRZ-1CT at 4:17-21.
[80] *Id.* at 5:3.
[81] *Id.* at 4:13-15.
[82] *Id.* at 5:3-6.
[83] *Id.* at 6:2-7.
[84] *Id.* at 5:10-17 (citing Western Electricity Coordinating Council, State of the Interconnection 2023 at 5 (Mar. 24, 2023) (available at https://www.wecc.org/Administrative/State%20of%20the%20Interconnection.pdf) (last visited Dec. 8, 2023).

market transactions modeled in Aurora decrease, which is evident in the historical data and must also be reflected in the NPC forecast through reasonable caps at all hubs.

36. Second, there is more uncertainty in load and generation due to increasingly common extreme weather events and higher penetration of intermittent generation across the West.[85] When faced with uncertainty, utilities tend to hold on to their generation because it is imperative that each utility have sufficient generation to serve its load.[86] This means that utilities are less likely to sell generation in bilateral markets and instead hold the generation until the intra-hour EIM when the utility is confident it will have sufficient generation to meet load. As the Company and other utilities in the West hold back generation in the face of increasing uncertainty, off-system market sales will decrease, as evidenced by the Company's steadily decreasing off-system sales volumes.[87]

3. AWEC's proposal to remove market caps from the Mid-Columbia, Palo Verde, and Four Corners hubs cannot be squared with current bilateral market conditions.

37. AWEC recommends the Commission remove the market caps from three hubs—Mid-Columbia (Mid-C), Palo Verde, and Four Corners—to further increase the level of off-system sales.[88] AWEC testifies that removing market caps from the Mid-C, Palo Verde, and Four Corners market hubs *increases* NPC by $341,965.[89]

38. The record in this case does not support AWEC's proposal. AWEC cites PacifiCorp's testimony in a Wyoming rate case from 2014 where the Company explained

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[85] *See* Mitchell, Exh. RJM-1CTr at 9:16-18.
[86] *See id.* at 9:19-21 (discussing how utilities are revising their load profiles in response to abnormal weather conditions).
[87] Zachariah, Exh. IMRZ-1CT (Confidential Figure CAPS-1).
[88] Mullins, Exh. BGM-1T at 44:10-14.
[89] Mullins, Exh. BGM-1T at 45:12-13. AWEC appears to have miscalculated the impact of its adjustment by running a different version of Aurora than the Company used to calculate NPC. Zachariah, Exh. IMRZ-1CT at 2:17-3:2. When the Company ran the Aurora model provided by AWEC, the actual impact of removing market capacity limits is an increase of $474,000. *Id.* at 2:14-15.

that *at that time* Mid-C and Palo Verde were liquid market hubs.[90] Since 2014, however, utilities, including the Company, are transacting less at all market hubs, including Mid-C, Palo Verde, and Four Corners.[91] Given this change in market conditions, AWEC's reliance on testimony from 2014 does not support removing market caps in this case and AWEC's proposal to increase Aurora's ability to make off-system sales runs directly counter to historical data showing declining off-systems sales.

D. The Commission should approve all NPC updates and corrections included in the Company's rebuttal filing or reject them all.

39. In its rebuttal filing, the Company included four corrections and two modeling updates to improve the accuracy of the NPC forecast.[92] The four corrections are titled: (1) Startup Costs; (2) Wind Capacity Factors; (3) Contingency Reserves for Non-Owned Generation; and (4) DA/RT Volume Component. The two modeling updates are titled: (1) Thermal Generation Marginal Costs; and (2) EIM greenhouse gas (GHG) Benefits. In the aggregate, these modifications decrease NPC by $4.4 million.[93]

40. In testimony, AWEC argued that the Rate Year 1 compliance filing update should be "very limited in scope" and include nothing other than updated study periods, the most recent OFPC, executed power purchase agreements, and load.[94] AWEC then shifted its position and now supports most of the updates and corrections—which cumulatively reduce NPC—but objects to the correction to the DA/RT volume component, which increases NPC by $5.2 million.[95] No other party takes issue with the Company's corrections and modeling updates.

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[90] Mullins, Exh. BGM-1T at 43:3-15.
[91] Zachariah, Exh. IMRZ-1CT (Confidential Figure CAPS-1).
[92] Mitchell, Exh. RJM-3CT at 14:14-19.
[93] *Id.* at 14:14-15.
[94] Mullins, Exh. BGM-1T at 21:14-18.
[95] Joint Issues Matrix at 10.

41. The DA/RT adjustment corrected an error by removing artificial revenue that was incorrectly imputed into the volume component at levels that exceed any historical revenues actually received by the Company through its system balancing transactions.[96] By correcting the error, the DA/RT adjustment's volume component now imputes the actual historical arbitrage revenue received by the Company into the NPC forecast and produces reasonable and logical results.

1. The DA/RT adjustment was approved to account for costs incurred in actual operations that are not captured in the fully optimized NPC forecast.

42. The Company's historical data demonstrates that it incurs system balancing costs that are not reflected in the Company's OFPC or modeled in Aurora.[97] To incorporate these costs in the NPC forecast, the Company uses the DA/RT adjustment—which consists of two components.[98] First, to better reflect the market prices available to the Company when it transacts in the real-time market, the Company models separate prices for forward system balancing sales and purchases.[99] The Company typically makes balancing purchases during higher-than-average periods and balancing sales during lower-than-average periods.[100] The price adjustment accounts for the historical price differences between the Company's purchases and sales compared to the monthly average prices used as an input to Aurora.[101] Second, the DA/RT adjustment reflects additional transaction volumes to account for the market's standard 25 megawatt (MW) block products, which are purchased or sold over various time horizons.[102] The volume

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[96] Mitchell, Exh. RJM-3CT at 18:9-21:6.
[97] Mitchell, Exh. RJM-1CT at 27:15-16.
[98] Exh. RJM-13X at 6:3-7:14.
[99] *Id.* at 6:4-8.
[100] *Id.* at 6:16-18.
[101] *Id.* at 6:7-8.
[102] Mitchell, Exh. RJM-3CT at 18:18-23.

component is necessary because Aurora assumes that the Company can transact in flexible increments that perfectly match system need, and it therefore models an unrealistically low volume of transactions.[103]

43. The Commission first authorized the DA/RT adjustment in the Company's 2020 rate case,[104] and the Company applied the DA/RT adjustment in the 2021 PCORC.[105] The DA/RT adjustment has been approved for use in all the Company's jurisdictions.

2. The Company's correction to the DA/RT volume component is reasonable.

44. The Company's rebuttal filing corrected an error in the volume component that was producing demonstrably erroneous results.[106] The purpose of the volume component is to adjust system balancing transaction volumes to reflect the *inefficiencies* and associated *costs* incurred in actual operations.[107] In the initial filing, however, the volume component was producing significant revenue of $102 million—well in excess of any realistic arbitrage revenue the Company received in actual operations, which has varied between $6.2 million and $9.3 million per year.[108] A calculation that is designed to simulate *costs* associated with real-world trading *inefficiencies* but produces substantial and unrealistic *revenue* is producing an erroneous result.[109] The correction resolved this error and then added into the NPC forecast realistic arbitrage revenues based on a historical 48-month average, which ensures that the volume component produces non-contradictory results.

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[103] *Id.* at 19:3-8.
[104] Exh. RJM-14X at 4:9-12.
[105] Mitchell, TR 103:20-104:16.
[106] Mitchell, Exh. RJM-3CT at 18:9-21:6.
[107] *Id.* at 19:9-11.
[108] *Id.* at 19:17-18.
[109] *Id.* at 19:20-23.

45. AWEC opposes the DA/RT volume component correction because the Company introduced the correction in its rebuttal filing.[110] However, correcting a demonstrative error is necessary to determining "with the greatest degree of precision that forward looking models can produce, an accurate estimate of actual costs that [the utility] will experience in the near and intermediate terms."[111]

3. If the Commission rejects the DA/RT correction, it should reject all other updates and corrections.

46. Although AWEC has suggested that the Company should not include any modeling changes in its updates,[112] AWEC objects only to one correction that increased NPC. To the extent that AWEC asserts the DA/RT adjustment correction is procedurally improper because it was raised for the first time in rebuttal testimony, that same conclusion would apply to other corrections and updates included in the Company's rebuttal filing, such as the update to the modeling logic applicable to thermal plant dispatch.[113] The thermal generation marginal costs update modified the modeling logic within Aurora's optimization to remove the usage of shadow prices to determine the marginal costs of both coal and gas generation subject to explicit seasonal or annual constraints, thereby allowing for increased flexibility in coal and gas generation.[114] The thermal plant dispatch modeling change decreased NPC by $9.7 million, Washington-allocated, which is greater than the increase resulting from the DA/RT adjustment correction.[115] In fact, in total the corrections and updates included in the Company's

[110] Joint Issues Matrix at 10; *see also* Mullins, Exh. BGM-1T at 21:21-23 (recommending that no modeling updates be included in NPC updates).
[111] Docket UE-210402, Order 06 at ¶ 124 (quoting *WUTC v. Puget Sound Energy, Inc.*, Docket UG-040640 *et al.*, Order No. 06 at ¶ 107 (Feb. 18, 2005)).
[112] Mullins, Exh. BGM-1T at 21:21-23
[113] Mitchell, Exh. RJM-3CT at 15:23-29.
[114] *Id.*
[115] *Id.* at 15:28-29.

rebuttal testimony decrease NPC by $4.4 million.[116] AWEC's position, if taken to its logical conclusion, would exclude all corrections and updates included in the rebuttal filing and thereby increase NPC. For these reasons, the Commission should reject AWEC's proposed adjustment and adopt all corrections and modeling updates included in the Company's rebuttal filing.

E. The Company's NPC modeling appropriately accounts for the BCC reclamation and depreciation costs.

47. Historically, reclamation and depreciation costs required for the BCC mine were included as a component of the fuel cost of coal provided by the mine for the Bridger plant. The level of reclamation costs included in the fuel cost was based on the expected life of the BCC mine as determined on a system-wide basis. In the Company's 2020 rate case, the Commission approved a settlement that called for accelerated depreciation of coal-fired resources and the BCC mine to 2023.[117] To accommodate this accelerated depreciation, the Commission approved a balancing account to track recovery of Washington's share of additional, incremental reclamation and depreciation for the BCC mine that Washington would have paid through fuel costs over the life of the mine, but would no longer pay once the mine was removed from Washington rates in 2023.[118] The balancing account reflects recovery of the estimated incremental BCC mine reclamation and depreciation costs based on an assumed 2023 closure date and costs were to be recovered over 10 years, from 2021 through 2030.[119] Together with the reclamation costs that would be recovered through fuel costs from 2021 to 2023, the balancing account was

[116] Cheung, Exh. SLC-8T at 25:17-19.
[117] Cheung, Exh. SLC-8T at 27:9-13; *WUTC v. PacifiCorp, dba Pacific Power & Light Co.*, Docket UE-191024 *et al.*, Order 09/07/12 at ¶¶ 110-11 (Dec. 14, 2020).
[118] Cheung, Exh. SLC-8T at 27:13-19.
[119] Cheung, Exh. SLC-8T at 27:19-21.

designed to capture 100 percent of the estimated reclamation costs that would be incurred over the life of the BCC mine. The intent of the balancing account is to ensure that Washington customers pay their share of reclamation costs, which means that any over or under recovery will be trued up at the end of the account life.[120]

48. In this case, the Company extended the life of coal-fired resources and the BCC mine from 2023 through 2025.[121] As a result, the Company recalculated the reclamation costs that would be recovered through fuel costs and adjusted the amounts that would be recovered through the balancing account so that together the fuel costs and balancing account would recover 100 percent of the estimated reclamation costs allocated to Washington, subject to a true-up of the balancing account.[122]

49. AWEC recommends removing reclamation costs from the cost of fuel, claiming the balancing account approved in the 2020 rate case was designed to capture *all* the BCC reclamation and depreciation costs and including depreciation and reclamation costs in fuel costs through 2025 results in double recovery.[123] AWEC is wrong.

50. First, there is no double recovery, and, in fact, there cannot be double recovery given that the purpose of the balancing account is to true-up reclamation and depreciation expense paid by Washington customers to the costs incurred in actual operations.[124]

51. Second, the settlement in the 2020 rate case does not prohibit recalculating the reclamation and depreciation costs in this case based on extending the life of the BCC mine. In fact, Staff agrees with the Company's position: "If the Commission approves the

[120] Cheung, Exh. SLC-8T at 30:3-5.
[121] Cheung, Exh. SLC-8T at 28:4-5.
[122] Cheung, Exh. SLC-8T at 28:20-29:8; Cheung, TR 138:9-18.
[123] Mullins, Exh. BGM-1CT at 33:17-34:2.
[124] Cheung, Exh. SLC-8T at 30:3-5.

proposal to revise the exit date for Jim Bridger coal units from 2023 to 2025, then PacifiCorp's method of calculating coal costs for the Jim Bridger units' contribution to NPC appears to be consistent with the intent of the [2020 rate case] settlement."[125] As PacifiCorp explained at hearing, the fuel costs here include recovery of reclamation and depreciation based on the system closure date for the BCC mine, which will be recovered from Washington customers through 2025.[126] The remaining difference between what would have been recovered through fuel costs based on the life of the mine and the amount recovered through the balancing account since 2021 will not be recovered through the balancing account.[127]

52. Third, cost recovery through the balancing account has decreased as a result of the Company's update in this case. The 2020 rate case settlement called for recovery of approximately $2.5 million per year for 10 years, for a total of approximately $25 million. As of 2023, the Company has recovered roughly $7.5 million. Going forward, the Company proposes recovering approximately $2 million per year through the balancing account for an additional seven years, for a total of approximately $14 million. Together with the $7.5 million already recovered, the Company projects total recovery of approximately $21.5 million in this case, as compared to $25 million in the 2020 case.[128]

53. Fourth, removing reclamation and depreciation costs from BCC fuel costs lowers those costs and, all else equal, increases dispatch of the plant. This means that Washington NPC would be based on higher Bridger plant dispatch than would occur in actual operations, where the fuel cost would reflect reclamation and depreciation costs.

[125] Wilson, Exh. JDW-24T at 11:10-14.
[126] Cheung, TR. 144:22-145:16.
[127] Cheung, TR. 137:6-20; Cheung, Exh. SLC-8T at 30 (Illustration A).
[128] Cheung, TR. 139:15-140:6.

F. AWEC's new adjustment related to incremental wheeling revenue must be rejected.

54. For the first time at hearing, AWEC proposed an entirely new and unsupported adjustment to NPC to impute wheeling revenue resulting from the new Gateway South transmission line.[129] Not only is there no evidence in the record supporting such an adjustment, wheeling revenue is included in base rates, not NPC. Therefore, imputing additional revenue into the NPC forecast is improper.

55. Moreover, the NPC forecast for both rate years one and two includes the full NPC benefits of new transmission investments, including Gateway South. And base rates for Rate Year 2 include a pro forma adjustment to increase wheeling revenues, although the pro forma adjustment is not tied to any specific transmission investment.

III. POWER COST ADJUSTMENT MECHANISM

56. The PCAM currently accounts for differences between forecast NPC and actual NPC using both deadbands and asymmetrical sharing bands.[130] The NPC variance first flows through a $4 million symmetrical deadband.[131] For variances between $4 million and $10 million, any credit to customers is subject to a 75/25 percent sharing band whereby 75 percent of the variance is returned to customers,[132] and any surcharge is divided between customers and the Company under a 50/50 sharing band.[133] Any surcharge or credit exceeding $10 million is subject to a 90/10 sharing band.[134] After applying these deadbands and sharing bands, the variances are booked in the PCAM

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[129] Pepple, TR. 89:20-24.
[130] Painter, Exh. JP-1T at 2:3-6.
[131] Painter, Exh. JP-1T at 3:4-8.
[132] Painter, Exh. JP-1T at 3:13-16.
[133] Painter, Exh. JP-1T at 3:16-19.
[134] Painter, Exh. JP-1T at 3:13-19.

deferral account and are then recovered from or refunded to customers when the account balance exceeds the credit or surcharge threshold, which is currently set at $17 million.[135]

57. The Company recommends removing the deadband and asymmetrical sharing bands, which would allow the Company to fully refund to customers any overcharges or recover its prudently incurred power costs.[136] As an alternative, the Company supports Staff's recommendation to remove the deadband and replace the asymmetrical sharing bands with a single 90/10 sharing band.[137] The Company also supports Staff's recommendation to decrease the credit or surcharge threshold to $7 million.[138] Staff's proposal is based in part on their agreement with the Company that the current PCAM structure is unnecessarily complicated and does not equitably share risk between the Company and customers,[139] that the increased prevalence of renewable generation will make it more difficult to forecast NPC,[140] and that many of the factors driving increased NPC are outside the Company's control.[141]

A. The Commission should eliminate the deadbands and sharing bands or adopt Staff's proposed 90/10 sharing band because the deadbands and asymmetrical sharing bands are no longer reasonable.

58. Prior to adopting the current PCAM, the Commission rejected proposals to create a PCAM without deadbands or sharing bands.[142] However, the Commission has not reevaluated the deadbands and sharing bands since they were adopted in 2015 and conditions have changed since that time that have made accurately forecasting NPC

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135 Painter, Exh. JP-1T at 4:2-9.
136 Painter, Exh. JP-1T at 8:8-9:3.
137 Painter, Exh. JP-2T at 3:2-4.
138 Painter, Exh. JP-2T at 6:7-12.
139 Wilson, Exh. JDW-1CT at 35:13.
140 Wilson, Exh. JDW-1CT at 27:1-7.
141 Wilson, Exh. JDW-1CT at 24 (Table 3).
142 *See* Docket UE-140762, Order 08 at ¶¶ 105-107 (summarizing prior PCAM proposals).

substantially more difficult. Additionally, based on actual experience, the current PCAM structure does not equitably share risk between the Company and customers and results in substantial customer losses. For these reasons, the Commission should either eliminate the deadbands and sharing bands or adopt Staff's 90/10 sharing bands.

1. Changing conditions have made accurately forecasting NPC more difficult, which increases the likelihood of NPC variance.

59. The current PCAM requires accurate NPC forecasts to function as intended.[143] However, changing conditions in the years since the Commission adopted the PCAM have made accurate forecasting much more difficult, leading to more substantial variance between forecast NPC and actual NPC.

60. The first condition affecting forecasts is the increased volatility in regional market price forecasts. Regional forward power market price forecasts were relatively stable in past decades, which meant that forecasting NPC using those relatively stable market prices was reasonably accurate.[144] By contrast, recent regional power market price forecasts have varied substantially, even on an intra-year basis.[145] For example, when comparing price expectations for January 2024 as measured during each quarter of 2022, the forecast increased significantly in each quarter.[146] Given the correlation between market prices and the Company's NPC,[147] these rapidly shifting price forecasts impair the Company's ability to accurately forecast NPC.

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[143] *See WUTC v. PacifiCorp*, Docket UE-061546, Order 08 ¶ 77 (June 21, 2007) (discussing risk that using "inaccurate . . . estimates of cost to set cost-based rates could lead [the Commission] to depart farther and farther from actual costs").
[144] Painter, Exh. JP-1T at 9:10.
[145] Painter, Exh. JP-1T at 14 (Figure 5).
[146] Painter, Exh. JP-1T at 14:9-10.
[147] Painter, Exh. JP-1T at 10 (Figure 2).

61. The second condition is the changing resource mix in the region as the Company and other utilities retire controllable thermal generation and replace it with intermittent weather-dependent generation.[148] Since the PCAM was adopted, renewable generation within the Company's system has nearly doubled and CETA compliance obligations will drive investment in even greater levels of renewable generation to serve Washington customers.[149] As weather-dependent generation continues to increase throughout the Company's system and the broader region, regional generation forecasts and the associated regional market price forecasts will become less accurate.[150] While the Company may be able to anticipate the total generation from particular renewable generation resources over the long term,[151] output from renewable generation during specific timeframes will be difficult to anticipate.[152] When, inevitably, the renewable generation deviates in actual operations from the forecast, the Company will have to re-dispatch with more expensive resources or market purchases, which will increase NPC compared to the forecast NPC that relied on the expected output from renewable generation.[153] Staff shares this concern, and explained "that NPC variability will increase as the portion of power supplied by renewable generation grows[.]"[154]

62. Finally, the increased prevalence of extreme weather conditions affects the Company's ability to accurately forecast NPC.[155] While the Company can anticipate that the frequency of extreme conditions will increase, these events are by definition uncertain

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148 Painter, Exh. JP-1T at 11:9-12:1.
149 Painter, Exh. JP-1T at 18:15-17; *id.* at 19:3-4.
150 Painter, Exh. JP-1T at 18:5-7.
151 Painter, Exh. JP-1T at 20:14-16.
152 Painter, Exh. JP-1T at 19:11-12.
153 Painter, Exh. JP-1T at 19:12-14.
154 Wilson, Exh. JDW-1CT at 27:1-7.
155 Painter, Exh. JP-1T at 16:6-8.

and may or may not materialize on time, or at all.[156] These extreme weather events affect the accuracy of both forecast market prices and renewable generation,[157] thereby exacerbating the impacts discussed above. For example, an unplanned heat wave will increase energy demand across the region, which will increase market prices as utilities all seek more market purchases simultaneously.[158] Similarly, when large areas experience similar weather patterns, such as low wind, this will decrease renewable generation throughout the region and cause a sudden variance in NPC.[159] This is evidenced by the fact that these forecasting concerns are not unique to the Company, but rather affect the entire utility industry.[160] For example, both Puget Sound Energy and Avista have experienced substantial imbalance in their power cost mechanisms in recent years.[161]

63. Sierra Club asserts that the difficulties in forecasting NPC result from the Company's reliance on natural gas generation due to the volatility of natural gas prices.[162] But the volatility in natural gas prices supports the Company's proposal to remove the deadbands and sharing bands or to replace them with a single 90/10 sharing band because that volatility directly impacts regional power market prices.[163]

64. AWEC similarly argues that volatility in the natural gas markets increases the forward price curves, which in turn causes NPC to be overstated.[164] However, AWEC's assertion oversimplifies the situation because it is the inaccurate NPC forecasts that cause

[156] Painter, Exh. JP-1T at 16:3-5.
[157] Painter, Exh. JP-1T at 15:10-16:6; *id.* at 19:14-20:4.
[158] Painter, Exh. JP-1T at 16:11-17.
[159] Painter, Exh. JP-1T at 20:2-7.
[160] Painter, Exh. JP-2T at 4:7-8.
[161] Painter, Exh. JP-2T at 4:13-5 (Tables 1 and 2).
[162] Binz, Exh. RJB-1T at 19:11-12.
[163] Painter, Exh. JP-2T at 10:5-8.
[164] Mullins, Exh. BGM-1T at 69:5-17.

variance, not solely the volatility in forward price curves.[165] Even if AWEC's assertions were accurate, an overstated NPC would support removal of the deadbands since the deadbands would prevent customers from receiving the full variance as a credit.[166]

2. In practice, the current deadband and sharing bands do not equitably share risk between customers and the Company.

65. The PCAM is intended to equitably share risk of NPC variability between the customers and the Company.[167] The PCAM has now been in effect for six years, however, and based on actual results it has not done so. In fact, the current deadband and sharing bands have negatively impacted Washington customers.[168] Between 2016, the first full calendar year in the PCAM, and the recent PCAM filing for 2021, the deadband and asymmetrical sharing bands have resulted in Washington customers paying $27.6 million more than they would have absent the deadbands and sharing bands, while the Company has simultaneously incurred $10.2 million in prudent NPC that was not recovered.[169] These losses show that Washington customers would have significantly benefited with a PCAM that did not contain a deadband or sharing bands.

66. The Company is not the only party concerned with how the current PCAM structure affects customers; Staff agrees that the current PCAM deadband and sharing bands do not equitably share risk between the customers and the Company and that "the PCAM mechanism has resulted in substantially more customer 'losses[.]'"[170] While

[165] Painter, Exh. JP-2T at 17:14-19.
[166] Painter, Exh. JP-2T at 17:19-21.
[167] Docket UE-140762, Order 09 at ¶ 64.
[168] Wilson, Exh. JDW-1CT at 31:9-16.
[169] Painter, Exh. JP-1T at 7:13-18.
[170] Wilson, Exh. JDW-1CT at 31:9-16.

several parties argue that the deadband and sharing bands are necessary to protect customers,[171] the facts say otherwise.

B. The Company has a strong incentive to control costs even without deadbands and sharing bands.

67. Another purpose of a PCAM is to incentivize the Company to effectively manage or reduce power costs.[172] However, even without the deadbands and sharing bands, or with Staff's 90/10 sharing bands, the Company already has a strong incentive to deliver low NPC because it must compete for customers in Washington, given the absence of exclusive service territories.[173] Moreover, the Company only recovers the base amount in current rates and must wait a year to true-up net power costs through the PCAM. The delayed recovery of prudently incurred power costs through the PCAM is sufficient incentive for the Company to produce an accurate NPC forecast.

68. To manage NPC, the Company can control the generation mix used to serve customers, ensure that its resources are efficiently operating, and that planned outages are prudently managed.[174] These discrete cost control measures, however, are already subject to active prudence review in the PCAM and if the Company is imprudent, those costs are removed before the deadbands and sharing bands are applied.[175] What this means is that the only costs that are disallowed by the sharing bands are costs that are prudent. And,

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[171] Mullins, Exh. BGM-1T at 6:7-8; Earle, Exh. RLE-1CT at 9:6-7; Binz, Exh. RJB-1T at 38:23-24.

[172] *See In the Matter of Avista Corporation, d/b/a Avista Utilities, For Continuation of the Company's Energy Recovery Mechanism, with Certain Modifications*, Docket UE-060181, Order 03 at ¶ 23, Finding of Fact 3 (June 16, 2006).

[173] *WUTC v. Pacific Power & Light Company*, Docket UE-161204, Order 06 at ¶ 25 (Oct. 12, 2017) (explaining that "Washington does not grant exclusive service territories to electric utilities by statute").

[174] *See, e.g.*, Painter, JP-2T at 12:14-19 (explaining that the Company optimizes scheduled maintenance outages to minimize costs and disruptions).

[175] Painter, Exh. JP-2T at 13:20-14:5; *See, e.g.*, *In the Matter of Investigation of Avista Corporation d/b/a Avista Utilities, Puget Sound Energy, and Pacific Power & Light Company Regarding Prudency of Outage and Replacement of Power Costs*, Docket UE-190882, Final Order 05 at ¶ 119 (March 20, 2020) (disallowing $457,000 incurred to acquire replacement power costs resulting from the 2018 Colstrip outage).

even without the sharing bands or with a single 90/10 sharing band, the Company will retain an incentive to control costs, because imprudent costs will be disallowed.

C. NPC are driven by costs that the Company cannot control.

69. The vast majority of NPC results from market forces outside the Company's control. In recent years, market prices increased significantly, which has driven higher NPC in actual operations.[176] While the Company has a low-cost, diverse generation portfolio and prudently manages its resources to maximize efficient performance and minimize outages, the Company cannot unilaterally dictate market prices, or the weather, or environmental regulations, all of which have significant and increasing impacts on NPC.[177] Staff has agreed that many of the drivers of NPC variation, including load, renewable resource generation, and market prices, are outside the Company's control.[178] Because the PCAM cannot incent the Company to control those factors over which it has no control, the deadbands and sharing bands in practice amount to a de facto disallowance of prudently incurred costs to provide service to Washington customers. This trend will increase further after the Company joins the EDAM in 2026.[179]

70. However, the Company will continue to control NPC to the extent possible by operating its system using an optimization model that focuses on achieving the least cost economic dispatch of its resources.[180] As evidenced by the optimization practices the Company currently applies in states where the Company recovers its NPC without

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[176] *See* Painter, Exh. JP-1T at 9:18-19 ("NPC are driven by and are proportionate to regional power market prices[.]").
[177] Painter, Exh. JP-1T at 13:6-13 (discussing weather forecasting impacts on NPC); *id.* at 19:3-4 (discussing NPC impacts of compliance with Washington environmental laws, including the CETA).
[178] Wilson, Exh. JDW-1CT at 24 (Table 3) (Staff identified the following as factors outside the Company's control: Load; Renewable resource generation; Market spot power prices; Unit dispatch; Wheeling rates; Qualifying facility contracts; Market fuel prices).
[179] Painter, Exh. JP-1T at 25:13-14.
[180] Painter, JP-2T at 12:10-13.

applying deadbands or sharing bands,[181] the Company will continue to minimize NPC to the extent possible if the Commission adopts the Company's or Staff's proposal.

D. The Company's proposal is consistent with power cost recovery mechanisms for most utilities.

71. The Company does not propose unique treatment for its power costs, but rather seeks a comparable opportunity to recover its power costs as other similarly situated utilities. Throughout the country, only eight states apply sharing bands in their fuel recovery mechanisms.[182] In fact, of comparable utilities in the Company's proxy group used to estimate its cost of equity, 88.24 percent are allowed to pass through fuel costs and purchased power costs directly to customers.[183] Approving the Company's proposal would merely put the Company on even footing with other comparable utilities, instead of possibly over-charging customers for NPC or increasing the Company's financial risk by not allowing full recovery of prudently incurred NPC.[184]

72. Even when considering only states in which the Company operates, Washington is an outlier. Most of those states have some type of either deadband or sharing band, but no other state's power cost mechanism results in similar customer losses. Of the five other states in which the Company operates, only Oregon includes deadbands.[185] Additionally, the sharing band in the PCAM allocates a smaller percentage of NPC variation to customers than the mechanism in any other Company state—Utah, the state with the largest Company load, and California do not apply any deadband or sharing

[181] Painter, JP-2T at 12:15-19.
[182] Bulkley, Exh. AEB-1Tr at 56:8-11 (the eight states with sharing bands are Arizona, Idaho, Missouri, Montana, Oregon, Vermont, Washington and Wyoming); *see also* Exh. JP-3 (summarizing power cost mechanisms in all states).
[183] Bulkley, Exh. AEB-1Tr at 14-16.
[184] Bulkley, Exh. AEB-1Tr at 16-22.
[185] Wilson, JDW-1CT at 20 (Table 2).

band; Idaho applies a 90/10 sharing band; and Wyoming uses an 80/20 sharing band.[186] Staff's proposed 90/10 sharing band in this case is "identical to that utilized by Idaho and also midway between the mechanisms used in Utah and Wyoming[.]"[187]

E. As an alternative, the Company supports Staff's recommended 90/10 sharing bands.

73. Staff recommends adopting a simpler PCAM that would include only a single 90/10 customer/Company sharing band.[188] While the Company believes that the fairest outcome for customers is to completely remove the sharing band in the PCAM, as an alternative, the Company supports Staff's recommendation of simplifying the asymmetrical sharing bands to a single 90/10 sharing band.[189]

74. However, the Company does not support Staff's recommendation to delay implementing changes to the PCAM until after the Company joins the EDAM.[190] As Staff acknowledges,[191] the current PCAM structure does not equitably share risks between customers and the Company,[192] and further delay will only extend the impacts of this inequitable treatment.

75. Moreover, Staff has also agreed that the EDAM is not the only factor affecting the accuracy of NPC forecasts; NPC variability will also occur due to increased renewable generation.[193] Renewable generation will continue to increase variability even before the Company joins the EDAM.

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[186] Wilson, JDW-1CT at 20 (Table 2).
[187] Wilson, Exh. JDW-1CT at 36:14-16.
[188] Wilson, Exh. JDW-1CT at 36:14-16.
[189] *Id.*
[190] Wilson, Exh. JDW-1CT at 39:3-4.
[191] Wilson, Exh. JDW-1CT at 31:14-16.
[192] Painter, Exh. JP-2T at 3:13-17.
[193] Painter, Exh. JP-2T at 3:17-4:3.

F. Modifying the PCAM does not violate the stipulation in which the parties agreed to adopt the PCAM.

76. AWEC has asserted that the Company's proposal to remove the deadbands and sharing bands from the PCAM amounts to "effectively withdrawing from" the stipulation that proposed the original PCAM structure.[194] Taken to its logical conclusion, AWEC's assertion would similarly affect Staff's proposal, because Staff was a party to the stipulation as well.[195] However, AWEC's suggestion that modifying the PCAM violates the agreement adopting that initial structure is incorrect.

77. As an initial matter, the stipulation in question was agreed upon in a very specific context. The Commission directed the Company to file a settled PCAM proposal, and if the Company failed to do so by a specific date, the Commission would order a mechanism consistent with Staff's proposal, rather than what was proposed by the Company in that proceeding.[196] The stipulation was intended to address the specific requirements the Commission had identified. Moreover, by its terms, the stipulation did not preclude the parties from adopting any position in future proceedings.[197]

78. Additionally, AWEC's suggestion that agreeing to the stipulation precluded the parties from modifying the PCAM structure is inconsistent with the subsequent history of the PCAM in which components have been modified. For example, the initial stipulated PCAM structure required amortization "over a 12-month period."[198] However, in the

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[194] Mullins, Exh. BGM-1T at 67:18-68:2.
[195] Docket UE-140762, Order 09 at ¶ 3.
[196] Docket UE-140762, Order 08 at ¶ 126.
[197] Docket UE-140762, Settlement Stipulation at ¶ 27 (May 8, 2015) ("By executing this Stipulation, no party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding.").
[198] Docket UE-140762, Settlement Stipulation at ¶ 18.

2021 PCAM, the Commission approved amortization over a two-year period.[199] For these reasons, AWEC's assertion that the Company is effectively withdrawing from the stipulation is incorrect.

IV. CONCLUSION

79. For the foregoing reasons, the Commission should approve the Company's forecasted NPC of $199 million, subject to the compliance filing updates discussed above for rate years one and two. Further, the Commission should approve the Company's proposal to eliminate the PCAM's deadbands and sharing bands or, in the alternative, adopt Staff's 90/10 sharing bands recommendation.

Respectfully submitted this 12th day of January 2024.

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[199] *In the Matter of PacifiCorp d/b/a Pacific Power & Light Company's 2021 Power Cost Adjustment Mechanism Annual Report*, Docket UE-220441, Compliance Acknowledgement Letter (December 28, 2022).