BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. PACIFICORP D/B/A PACIFIC POWER & LIGHT COMPANY Respondent.	)	DOCKET UE-250224

OPENING BRIEF

ON BEHALF OF THE

ALLIANCE OF WESTERN ENERGY CONSUMERS

(Redacted Version)

October 29, 2025

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I. INTRODUCTION

1 Pursuant to the Washington Utilities and Transportation Commission's ("Commission") Order 03 in the above-referenced docket, the Alliance of Western Energy Consumers ("AWEC") hereby files this Opening Brief.

II. BACKGROUND

2 This case arises out of PacifiCorp's most recent multi-year rate plan in which the Commission ordered PacifiCorp to file a PCORC by April 1, 2025, both to remove coal-fired resources from Washington rates and also to "consider other revenue-requirement elements that may offset increases to NPC."[1] A PCORC "is a form of proceeding that allows [a utility] to periodically adjust its power costs to account for changes such as the addition of generation assets…[and to] reduce or eliminate regulatory lag."[2] In addition, in its final order on PacifiCorp's 2022 Power Cost Adjustment Mechanism, the Commission determined that it needed to "revisit the concept of the WIJAM" and ordered PacifiCorp "in the next rate case proceeding … [to] propose alternatives [to the WIJAM] to ensure Washington customers experience fair, just and reasonable rates."[3]

3 In this PCORC, PacifiCorp proposes a wholesale change to its Washington allocation methodology, known as the Washington 2026 Protocol. The Washington 2026 Protocol changes the allocation of generation resources by: (1) removing all coal-fired facilities from Washington rates; (2) assigning 100% of the Chehalis gas plant to Washington; (3) reducing the allocation

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1 *WUTC v. PacifiCorp dba Pacific Power & Light Company*, Docket Nos. UE-230172 and UE-210852 (*Consolidated*), Order 09/07 at ¶¶ 13-14 (May 16, 2024).

2 *WUTC v. Puget Sound Energy*, Docket Nos. UG-040640, UE-040641, UE-031471, and UE-032043 (*Consolidated*), Order 06 at footnote 34 (Feb. 18, 2005).

3 *WUTC v. PacifiCorp dba Pacific Power & Light Company*, Docket No. UE-230482, Order 07 at ¶ 111 (Oct. 30, 2024).

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percentage of the Jim Bridger ("JB") gas-fired units; (4) removing the Hermiston gas plant from Washington rates; and (5) assigning Oregon's disallowed share of the Rolling Hills wind facility to Washington.[4] PacifiCorp also proposes to fix the allocation percentages of generation resources to Washington (rather than allowing those percentages to change as Washington's load percentage of the system changes over time). Further, the Washington 2026 Protocol makes other changes that are not directly related to power costs, including modifying how the System Overhead factor is calculated, and specifying the recovery of future decommissioning and remediation costs for coal-fired facilities from Washington customers.

III. ARGUMENT

A. Interjurisdictional Allocation

4 AWEC recommends that the Commission decline to approve the Washington 2026 Protocol in this proceeding, which is dedicated to reviewing PacifiCorp's power costs in isolation from the other components of its revenue requirement. The scope of a PCORC is meant to be confined to net power costs and, thus, does not consider a utility's entire operations.[5] As such, when a new allocation methodology is proposed under a PCORC, the impacts of the proposed methodology cannot be reviewed with the context of a utility's entire operational scheme. Should a new allocation methodology be approved in a PCORC, once that methodology is applied on a broader scale, there may be unintended consequences with how the new allocation methodology affects the rest of the utility's operations.[6]

5 Notwithstanding this overall recommendation, AWEC does not oppose the Commission approving changes to PacifiCorp's allocation of generation resources in this case, given that

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4 Cheung, Exh. SLC-1T at 3:10-4:5.
5 *Supra* n. 2.
6 Mullins, Exh. BGM-1CT at 12:15-13:11.

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these resources directly impact NPC.[7] In effect, the Commission's review and approval of allocation changes in this case should be commensurate with the scope of the case. The Commission previously found that the WIJAM no longer yields just and reasonable rates for Washington customers, a conclusion with which AWEC agrees, but it required PacifiCorp to propose alternatives to the WIJAM "in the next rate case proceeding."[8] The PCORC is not a full rate case – it is a rate case for power costs only. As such, reviewing those allocations that impact power costs in this case is reasonable; but it is not reasonable to review and approve allocations that primarily impact other revenue requirement items, such as the System Overhead factor.

6 PacifiCorp argues that postponing full approval of the Washington 2026 Protocol will create "more uncertainty, which will make planning more difficult and risk increasing costs for Washington customers."[9] Witness Steward points to section 2 of the Washington 2026 Protocol, arguing that it addresses AWEC's concerns about approving the full Washington 2026 Protocol in this case:

> **2. Prudence.** The proposed allocation of a particular expense of investment under the Washington 2026 Protocol is not intended to and will not prejudge, or prevent any party from taking a position on the prudence of those costs or the extent to which any particular cost may be reflected in rates. Nothing in the Washington 2026 Protocol is intended to abrogate the Commission's right or obligation to: (1) determine fair, just, and reasonable rates based upon applicable laws and the record established in the rate proceedings conducted by the Commission; (2) consider the impact of changes in laws, regulations, or circumstances on inter-jurisdictional allocation policies and procedures when determining fair, just, and reasonable rates; or (3) establish different allocation policies and procedure for purposes of allocating costs and revenues to different customers or customer classes.[10]

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7 *Id.* at 12:5-14.
8 *Supra* n. 3.
9 Stewart, Exh. JRS-2T at 23:5-6.
10 *Id.* at 23:9-24. *See also* Link, Exh. RTL-2 at 2.

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AWEC agrees that this provision does not limit the Commission's authority to address jurisdictional allocation issues. However, this provision does not protect stability in rates, should the Commission approve the Washington 2026 Protocol now, but find it insufficient in the next rate case. In effect, PacifiCorp asks the Commission to determine that its entire allocation scheme is prudent when the overall impact of the allocations cannot be known until all of PacifiCorp's rates are at issue. While the Commission might be able to revise its approval of the Washington 2026 Protocol in a future case, PacifiCorp will have reasonably relied on a Commission decision that the Washington 2026 Protocol is prudent. This could raise concerns that the Commission acted arbitrarily and capriciously in finding that the Washington 2026 Protocol is a prudent allocation scheme overall, only to modify an aspect of that scheme in a future case. The only way to affirm that the Washington 2026 Protocol is a prudent cost allocation methodology for PacifiCorp's Washington customers is to holistically review the methodology with reference to PacifiCorp's entire operations.

7 For these reasons, the Commission should defer any determination on the Washington 2026 Protocol as a comprehensive allocation methodology to PacifiCorp's next general rate case; however, it is reasonable for the Commission to consider, in this case, the allocation proposals PacifiCorp makes with respect to its generation facilities, as how these facilities are allocated directly impacts the Company's Washington-allocation NPC.

1. <u>The Commission should approve PacifiCorp's reassignment of Chehalis entirely to Washington.</u>

8 The most significant allocation proposal PacifiCorp makes in this proceeding from both a cost and reliability perspective is to assign 100% of Chehalis to Washington customers. Directly assigning Chehalis to Washington reduces PacifiCorp's net revenue requirement by nearly $27

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million.[11] Meanwhile, Chehalis provides the vast majority of generation capacity allocated to Washington once coal-fired resources must be removed.[12] Commission Staff also supports Chehalis' reassignment to Washington.[13]

9 Public Counsel, however, argues that the Commission should fully remove all coal and natural gas from rates in order to meet CETA's 2030 requirements.[14] Public Counsel argues that the reallocation of Chehalis would make Washington customers over-reliant on a single asset, and a prolonged outage at Chehalis could result in a significant short position that may result in exposure to high market prices.[15] However, rejecting the reassignment of Chehalis today based on what may be required in 2029 to be CETA compliant is premature and unpersuasive. Since coal mut be removed from rates by the end of 2025, natural gas plants offer the next reliable source of dispatchable energy in PacifiCorp's portfolio. Requiring the Company to remove natural gas generation four years before it may need to do so under CETA[16] will likely result in PacifiCorp exposing Washington customers to an even greater price risk, should renewable resources fail to generate sufficient energy to meet load requirements. A full-capacity, dispatchable resource in Washington's portfolio mix will offer valuable protection in the form of resource adequacy that should weigh heavily in the Commission's decision-making process.

10 In any event, it appears that Public Counsel no longer advocates for the position it took in pre-filed testimony. At the hearing, Public Counsel Witness Earle substantially revised his recommendation for the treatment of resource adequacy between PacifiCorp's jurisdictions. In

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11 Mullins, Exh. BGM-1CT at 65:18-66:2.
12 Wilding, Exh. MGW-5CT at 3 (Confidential Figure 1).
13 Wilson, Exh. JDW-1T at 11:1-12.
14 Earle, Exh. RLE-1CT at 14:17-18.
15 *Id.* at 13:17-14:4.
16 *See* Hearing Tr. Vol. I, 248:13-24, Oct. 7, 2025.

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response to PacifiCorp's Rebuttal Testimony, which identified significant problems with Washington's resource adequacy position under Public Counsel's initial recommendation, Dr. Earle proposed to create a subscription-based payment system where, if a resource is over-allocated to a PacifiCorp jurisdiction based on need, other jurisdictions that are "short" on resource adequacy can "subscribe" to a resource to meet their needs.[17] This proposal, however, creates a host of problems that would need to be addressed and would likely not avoid an assignment of carbon emissions to Washington.

11 First, Public Counsel proposed this alternative during the public evidentiary hearing, leaving parties no time to fully explore the true impact of its proposal, nor create a sufficient record for the Commission to base its decision. Further, Public Counsel intends for this to be a generic payment between jurisdictions based on a state's "subscription" to a resource.[18] However, Public Counsel failed to resolve CETA implications prior to making its recommendations.[19] Under CETA, coal-fired resources cannot be in rates past 2025. A generic payment would need to ensure compliance with this requirement, and even Dr. Earle conceded that it was not clear his proposal would.[20] Further, in his rebuttal testimony on the stand, PacifiCorp Witness Wilding confirmed that a generic resource adequacy payment, even if compliant with CETA's coal restrictions, would still likely result in the assignment of greenhouse gas emissions to Washington.[21] There is also no evidence in the record on what such a payment would cost Washington customers. Accordingly, Public Counsel's proposal unnecessarily complicates the record to include an alternative that is not demonstrably preferable

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17 Hearing Tr. Vol. II 405:13-406:18, Oct. 8, 2025.
18 *Id*. at 409:13-23.
19 *Id.* at 410:2-3.
20 Earle, Tr. at 409:24-410:12.
21 Wilding, Tr. at 427:14-428:4.

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to PacifiCorp's recommendation to reassign Chehalis to Washington and could very well be significantly worse. For these reasons, AWEC recommends that the Commission reject Public Counsel's recommendation.

12 Staff[22] and Public Counsel[23] also raise concerns regarding overallocation of PacifiCorp generation resources on a total-Company basis. Both parties flag that PacifiCorp may be over-recovering its investment for some generation resources based on the sum of allocation factors to all of its jurisdictions.[24] The Commission should disregard this concern for the simple reason that it is not relevant what PacifiCorp's total Company recovery is. It only matters for the Commission's decision whether Washington's rates are fair, just, reasonable, and sufficient.[25] This is a principle the Commission has long recognized, noting that PacifiCorp "assumed any risk of under-recovery of costs due to states approving different [allocation] methodologies."[26] Indeed, the Commission has used a different cost allocation methodology for PacifiCorp than for all other states since 2007 when it adopted the West Control Area methodology with full knowledge that this would not result in perfect cost recovery on a total-Company basis.[27] If PacifiCorp takes the risk that divergent allocation decisions will result in under-recovery on a total-Company basis, it stands to reason that it should also receive the benefit if those same decisions result in over-recovery on a total-Company basis. Staff and Public Counsel offer no reason for the Commission to diverge from this longstanding principle.

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22 Wilson, Exh. JDW-1T at 16:13-15.
23 Earle, RLE-1CT at Section VII.
24 *Id.* at 23:12-24:3.
25 RCW 80.28.010(1).
26 *WUTC v. PacifiCorp dba Pacific Power & Light Co.*, Docket No. UE-130043, Order 05 at ¶ 81 (Dec. 4, 2013).
27 *Id.* ¶ 80 (*citing* Docket Nos. UE-061546 & UE-060817 (*Consolidated*), Order 08 at ¶¶ 49-52 (Jun. 21, 2007)).

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2. The Commission should remove Jim Bridger Units 1 and 2 ("JB 1 & 2") from rates, or alternatively, should replace JB 1 & 2 with the Hermiston gas plant.

13 As part of its reallocation of generation resources to Washington, PacifiCorp proposes to reduce Washington's share of the Jim Bridger Units 1 & 2 gas conversion units from 22.3% to 7.9%.[28] AWEC recommends that PacifiCorp remove Jim Bridger Unites 1 & 2 from rates entirely.[29] Removing Jim Bridger Units 1 & 2 fully from customer rates will provide a net benefit to customers both from a cost and emissions perspective. As Witness Mullins points out, the Jim Bridger units are thermally inefficient gas boilers "with emissions that are nearly double those of a combined cycle combustion turbine," especially compared to Chehalis and Hermiston.[30] The consequence of these inefficiencies is higher power costs and higher assigned emissions.[31]

14 PacifiCorp argues that a full elimination of the units would impact Washington's resource adequacy position.[32] PacifiCorp argues further that, as it brings more renewable energy resources online to meet clean energy targets, the units will play a critical role in reliable system operations.[33] However, these concerns are largely addressed through PacifiCorp's 100% allocation of Chehalis to Washington.[34] Mr. Mullins notes that, with Chehalis' reassignment,

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28 Mullins, Exh. BGM-1CT at 67:1-2.
29 *Id.* at 68:1-4.
30 *Id.* at 68:5-9.
31 *Id.* at 68:9-12.
32 Wilding, Exh. MGW-5CT at 6:17-18.
33 *Id.* at 7:19-22.
34 Compare Wilding, Exh. MGW-9X and MGW-10X. Under WIJAM, Chehalis provides 99.8 to 103.27 MW towards Washington's resource adequacy position, and Jim Bridger Units 1 & 2 provide between 141.56 to 153.12 MW. Under the 2026 Protocol, Chehalis will provide 491.64 to 508.73 MW towards the resource adequacy position, and Jim Bridger Units 1 & 2 only provide 55.09 to 59.59 MW. Thus, under the 2026 Protocol, Chehalis provides nearly 5 times more resource adequacy where the removal of Jim Bridger Units 1 & 2 would only leave, at most, 60 MW short in resource adequacy which can easily be made up with the Chehalis reassignment.

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"Washington continues to be in a net-long energy position, even without the generation from [JB 1&2]."[35] Further, as Exhibit MGW-7CX shows, the vast majority of Washington's resource adequacy position is provided by Chehalis, with JB 1 & 2 providing relatively little resource adequacy.[36]

15 However, if the Commission accepts PacifiCorp's position that even a modest amount of additional resource adequacy is necessary for Washington, it should replace an allocation of Jim Bridger Units 1 & 2 with an allocation of the Hermiston plant. PacifiCorp confirmed that Hermiston is capable of providing reliability benefits to Washington.[37] Continuing Hermiston's allocation to Washington would provide an additional 39.50 to 43.30 MW toward to Washington's resource adequacy position, only slightly less than JB 1 & 2's 55.09 to 59.59 MW,[38] and would do so at significantly lower cost to customers.[39]

3. <u>The Commission should not accept an additional allocation of the Rolling Hills wind plant, unless it also accepts AWEC's adjustment on wind curtailments.</u>

16 PacifiCorp proposes increasing Washington's allocation of the Rolling Hills wind facility from 7.9% to 34.87%.[40] The additional allocation comes from the portion of Rolling Hills disallowed in rates by the Oregon Public Utility Commission.[41] PacifiCorp argues that this increased allocation will help satisfy CETA's clean energy requirements and reduce customer

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35 Mullins, Exh. BGM-1CT at 68:12-13.
36 Mullins, Exh. BGM-3 at 22.
37 Wilding, Exh MGW-8X.
38 Exh. MGW-9X and Exh. MGW-10X.
39 Mullins, Exh. BGM-1CT at 66:3-13 (showing a net revenue requirement benefit from Hermiston of approximately $2.3 million).
40 Steward, Exh. JRS-1T at 5:20-23.
41 Link, Exh. RTL-1T at 8:10.

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exposure to market purchases.[42] The net monetary impact of the increased allocation is an increase of $4.25 million in revenue requirement.[43]

17 In addition to being costly for customers, Rolling Hills provides relatively little clean energy value. As explained by Witness Mullins, Rolling Hills has the second highest curtailment rate of any resource based on PacifiCorp's curtailment modeling approach, resulting in an Aurora-modeled capacity factor of only [redacted]%.[44] Staff also expressed concern with Rolling Hills' high curtailment rate.[45] PacifiCorp argues that there "are few opportunities to secure operational CETA-compliant generation."[46] However, PacifiCorp currently has a request for proposal out that will aid in the procurement of CETA-compliant resources by 2030.[47] Additionally, as also noted by Public Counsel[48] and Staff,[49] the higher-than-average costs to run Rolling Hills should be a significant consideration in the Commission's decision to approve an increased allocation of the wind facility. A capacity factor of less than [redacted] percent does not provide a significant additional benefit for Washington customers in avoiding market purchases, if the wind facility can only produce, on average, [redacted] MW of power.[50]

18 For these reasons, AWEC opposes PacifiCorp's increased allocation of Rolling Hills under the Company's modeling approach. AWEC's recommendation with respect to wind curtailments, discussed in detail in Section B of this Opening Brief, however, materially improves the modeled benefits of Rolling Hills, cutting the revenue requirement increase by

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42 Link, Exh. RTL-1T at 8:14-21 and 9:16-10:2.
43 Mullins, Exh. BGM-1CT at 70:12-18.
44 *Id.* at 21 (Confidential Table 2).
45 Wilson, Exh. JDW-1T at 24:1-3.
46 Link, Exh. RTL-3T at 23:1-3.
47 Docket UE-250460, PacifiCorp's Petition for Partial Waiver of WAC Chapter 480-107 and Approval of the Draft 2025 RFP at ¶ 12 (Jun. 10, 2025).
48 Earle, Exh. RLE-1CT at 22:3-16.
49 Wilson, Exh. JDW-1T at 24:4-8.
50 Mullins, Exh. BGM-1CT at 23 (Confidential Table 2). Rolling Hills has a nameplate capacity of 100 MW.

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approximately half.[51] Accordingly, while AWEC opposes reallocation of Rolling Hills as modeled by PacifiCorp, AWEC would not oppose this reallocation if the Commission also accepts AWEC's adjustment to modeled wind curtailments.

4. The Commission should approve PacifiCorp's proposal to fix generation factors.

19 PacifiCorp proposes to fix generation factors for Washington in this case, meaning that the percentage of each generating unit allocated to Washington will not change as Washington's load changes relative to the entire system.[52] AWEC supports this proposal because a transition to a fixed system generation factor benefits Washington customers. The SG factor under WIJAM is a dynamically-calculated generation allocation that is recalculated every year based on an individual state's relative load and demand on the system.[53] The goal of the 2020 Multi-State Protocol ("2020 Protocol") was to ultimately shift PacifiCorp's cost allocations away from dynamic to fixed allocation factors.[54] The transition to fixed allocation factors was also identified in section 5.1.2 of the WIJAM.[55] AWEC believes that fixing allocation factors will aid Washington during this time of growing loads in the West.[56]

20 Staff argues that the SG factor should be updated in each general rate case or PCORC based on a four-year average.[57] Staff's proposal would effectively maintain dynamic allocation for Washington generation resources. While Staff argues that its recommendation is more equitable for Washington, AWEC Witness Mullins shows that loads in other PacifiCorp

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51 Mullins, Exh. BGM-1CT at 71:4-7.
52 Steward, Exh. JRS-1T at 5:11-15.
53 Mullins, Exh. BGM-1CT at 63:5-9.
54 Link, Exh. RTL-1T at 4:11-14.
55 *See also* Link, Exh. RTL-1T at 4:18-19.
56 Mullins, Exh. BGM-1CT at 64:5-6.
57 Wilson, Exh. JDW-1T at 30:13-31:2.

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jurisdictions have historically grown at a faster rate than Washington's load growth.[58] Should the SG factor continue to have a dynamic allocation, Washington may potentially be paying for a large share of the resources today while being allocated smaller shares of the resources in the future, which would be inequitable for Washington customers. By fixing the SG factor, Washington customers are likely, in the long run, to receive a larger benefit of system resources than would otherwise be allotted under a dynamic allocation.

21 Moreover, as PacifiCorp testifies, a dynamic allocation factor significantly complicates the Company's ability to comply with CETA because it will not have a fixed generation portfolio on which to build toward CETA's clean energy mandates.[59] This creates unnecessary risk both for PacifiCorp and its Washington customers.

5. The Commission should reserve approval of a Washington-specific hedge book for review under a PCAM proceeding.

22 PacifiCorp proposes to modify its energy supply risk management policy to create a hedge book specific for Washington.[60] While AWEC does not necessarily oppose some recognition of Washington-specific hedges, AWEC does not believe that it is necessary for the Commission to address this "hedge book" in this docket.[61] The hedges PacifiCorp executes and allocates directly to Washington under its proposed method will impact actual power costs that are reviewed in the Company's PCAM docket.[62] As such, that docket is the appropriate place to review and determine the prudency of PacifiCorp's hedging practices and policies. If the Commission were to approve a Washington-specific hedge book in this case, it would be doing

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58 Mullins, Exh. BGM-8T at 7:14-16.
59 Link, Exh. RTL-3T at 26:2-9.
60 Wilding, Exh. MGW-1CT at 11:2-15:23.
61 Mullins, Exh. BGM-1CT at 73:20-74:15.
62 *Id.* at 73:9-12.

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so without full knowledge of the actual power cost impacts of this allocation scheme and would potentially pre-approve the associated costs.[63] PacifiCorp should bear the burden and take the risk of making prudent decisions in practice. If the Washington-specific hedge book is a prudent action for Washington, the Company will be able to demonstrate this in a subsequent PCAM. There is no need for a Commission decision in this case.

6. The Commission should reserve the review of other aspects of the Washington 2026 Protocol not directly related to NPC until PacifiCorp's next rate case.

23 As part of the initial filing, PacifiCorp makes a number of proposals under the Washington 2026 Protocol that are outside of the scope of this filing. As such, the Commission should reserve its review of these provisions, including the updated SO factor allocation, transmission cost allocation, coal decommissioning and remediation costs, and PacifiCorp's treatment of new large load.

24 With respect to the SO factor, PacifiCorp has proposed to modify the calculation to be an average of three separate factors: System Capacity, System Energy, and System Gross Plant Distribution.[64] The current SO factor calculation under WIJAM is dependent on the SO-allocated gross plant balances.[65] PacifiCorp argues that this change is necessary because the current calculation complicates the realignment of generation resources contemplated under the Washington 2026 Protocol.[66] However, PacifiCorp also admits that the SO factor is not generally applicable to power production, and instead the calculation change is needed to address general and administrative expenses.[67] This calculation change will result in an increase to

63 *Id.* at 73:12-15.
64 Link, Enh. RTL-1T at 17:20-22.
65 *Id.* at 17:18-20.
66 *Id.*
67 Cheung, Exh. SLC-1T at 3-17.

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Washington of $2.21 million.[68] This filing is intended to be a PCORC, and administrative and general costs generally fall outside the scope of this proceeding.[69] Additionally, PacifiCorp does not appear to propose fixing the SO factor in its proposal. If the SO factor is intended to remain dynamic, then there is no pressing need to address this calculation factor and its impacts on non-PCORC items in this proceeding.

25 As part of the Washington 2026 Protocol, PacifiCorp also proposes to continue to allocate "ongoing and expected decommissioning expenses for a WIJAM/WCA share of Jim Bridger Units 3-4 and Colstrip Unit 4 consistent with the previous terms of the WIJAM."[70] The Washington 2026 Protocol does not address decommissioning and remediation ("D&R") costs for gas-fired resources and instead intends to address the allocation of such costs in a future rate proceeding or through Phase 2 of the allocation process.[71]

26 The allocation of D&R costs associated with coal-fired resources is not a power cost issue and, therefore, should not be decided in this docket. However, if the Commission were inclined to resolve coal plant D&R costs in this case, PacifiCorp's proposed allocation is not fair and equitable to Washington customers. The allocation of those costs should be based on the benefits provided by the resource to Washington customers, not on WIJAM allocation factors in perpetuity, even after the plant is removed from Washington rates. In other words, Washington customers should be responsible for no more than a pro rata allocation of D&R costs based on how long a resource was in Washington's rates, relative to the total life of the facility. It would be unfair and unreasonable for Washington customers to pay a full allocated share of D&R costs

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68 Cheung, Exh. SLC-1T at 9:19-21.

69 *WUTC v. Puget Sound Energy*, Docket Nos. UE-0702300 and UG-072301 (*Consolidated*), Order 13 at ¶ 37 (Jan. 15, 2009).

70 Link, Exh. RTL-2 at 3, § 10.

71 Link, Exh. RTL-1T at 19:4-8.

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if other states continue to benefit from these plants after 2025. Such a result would require Washington customers to subsidize other states.

27 Finally, Staff proposes that PacifiCorp should include a provision regarding treatment of new large load that is present in the 2026 Protocol applicable to other jurisdictions.[72] This provision states:

> The costs associated with New Large Load that requires PacifiCorp to make investments or incur costs for assets placed in service after January 1, 2026, will be assigned to the state in which the load is located. PacifiCorp will work within the regulatory framework (i.e., a special contract or tariff) within that state to assign the costs to the New Large Load customer, as determined by that state's Commission. These costs include, but are not limited to, any new distribution costs, transmission costs, generation costs (including power purchase agreements, as applicable), and contractual costs for providing electrical service (i.e., firm third-party transmission rights).

Staff believes that the inclusion of this provision provides useful clarification to jurisdictional cost allocation.[73] PacifiCorp supports the adoption of this language for Washington.[74]

28 AWEC, conversely, is not convinced this provision provides useful clarity on jurisdictional allocation. PacifiCorp appears to propose direct assignment of transmission and generation costs to individual customers and, by extension, the state in which that customer is located. Such costs have not historically been allocated to individual customers, so it is unclear how the Company would determine when and whether a single customer was the sole cause of such an investment. How, for instance, would transmission costs be allocated to individual customers? The 2026 Protocol does not answer this question. Accordingly, there is significant uncertainty over how this provision would be implemented and the implications for Washington

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72 Wilson, Exh. JDW-1T at 33:10-34:3.
73 *Id.* at 34:2-3.
74 Link, Exh. RTL-3T at 2:28-30.

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rates. Given also that this provision is not directly germane to PacifiCorp's power costs, it should be considered as part of a larger review of PacifiCorp's proposed Washington 2026 Protocol in its next general rate case where the ambiguities inherent in PacifiCorp's proposal can be more fully developed.

7. The Commission should review the allocation of industrial curtailment contracts in PacifiCorp's next rate case.

29 AWEC is concerned that PacifiCorp allocates two industrial contracts located in Utah and Idaho to Washington customers and has recommended that the Commission reduce PacifiCorp's request by $2 million to remove the contracts.[75] Washington has not previously approved the rates for these contracts, and with a move to fixed allocation factors, there is no clear way to allocate the costs and benefits of these contracts to Washington ratepayers.[76]

30 PacifiCorp testifies that the industrial curtailment contracts allow PacifiCorp generation to direct industrial customers to curtail their load with little notice under certain conditions, as described within the contracts.[77] The industrial curtailment contracts, according to PacifiCorp, "fulfill a significant portion of [NERC contingency reserve requirements] and free up other generating resources that would otherwise have to hold this reserve capacity."[78] PacifiCorp further argues that allocating costs and benefits of these contracts is no different that allocating the costs and benefits of renewable resources in other states.[79]

31 PacifiCorp's testimony notwithstanding, AWEC continues to have concerns about allocating the costs of contractual resources that Washington neither oversees nor approved. For

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75 Mullins, Exh. BGM-1CT at 73:9-18.
76 *Id.* at 73:15-17.
77 Wilding, Exh. MGW-5CT at 17:2-4.
78 *Id.* at 17:4-10.
79 *Id.* at 17:22-18:2.

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this reason, while AWEC is willing to accept their inclusion in rates in this case, AWEC recommends that the Commission require PacifiCorp to provide additional justification for these contracts in its next rate case and that the Commission revisit whether the costs of these contracts should continue to be allocated to Washington based on this evidence.

B. Net Power Costs

1. The Commission should eliminate or reduce PacifiCorp's modeled wind curtailments.

32 In this case, PacifiCorp has modeled the output of its wind resources in a manner that assumes a significant percentage of their production is curtailed. Specifically, PacifiCorp's wind resources produce 21.1% less energy as an output from Aurora than the amount input into this model.[80] This point is not disputed.[81] The consequence of this is both higher costs – in the form of lost zero-cost energy and production tax credits – and higher emissions assigned to Washington.[82]

33 AWEC's witness, Bradley Mullins, identifies the cause of these modeled curtailments to be primarily minimum output requirements for PacifiCorp's coal resources, none of which will be allocated to Washington after this year and many of which have never been allocated to Washington, coupled with modeled market capacity limits and the fact that, unlike other Washington utilities, PacifiCorp models a closed system in Aurora, meaning there is no ability for the model to deal with oversupply conditions.[83] AWEC's adjustment to eliminate these modeled curtailments reduces PacifiCorp's NPC by approximately $19.5 million.[84]

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80 Mullins, Exh. BGM-1CT at 24:3-6.
81 Mitchell, Exh. RJM-13CT at 58:2-6.
82 Mullins, Exh. BGM-1CT at 24:6-13.
83 *Id.* at 35:10-36:5; Mullins, Tr. at 490:20-492:12.
84 Mullins, Exh. BGM-1CT at 3 (Table 1).

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34 PacifiCorp accuses Mr. Mullins of making numerous modeling errors in an attempt to discredit his adjustment. The Commission, however, does not need to delve into the weeds of Aurora modeling to resolve this dispute. Objective data demonstrate the reasonableness of AWEC's adjustment or, at the very least, the need for *some* reduction to the modeled curtailments of PacifiCorp's wind resources. Confidential Table 3 on page 26 of Mr. Mullins' Response Testimony shows the Company's wind resources, the capacity factor input into the Aurora model, and whether that capacity factor is based on the "P50" forecast or a four-year historical average.[85] Confidential Table 2 on page 23 of Mr. Mullins' Response Testimony then compares the capacity factors input into Aurora and the capacity factors that result from the model's output. PacifiCorp does not dispute any of this data.[86] Every one of the resources for which actual historical data was input into the model have a lower capacity factor as a modeled output.[87] This is despite the fact that the historical data incorporates curtailments that have actually occurred during this four-year period.[88] For all of its complaints about Mr. Mullins' modeling, PacifiCorp does not explain why it is reasonable for the modeled output of the Company's wind resources to be materially lower than the *actual historical output* of these resources.

35 In its response to Bench Request 02, PacifiCorp attempts to complicate the issue by introducing several new theories surrounding its use of a 48-month average to forecast wind

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85 The P50 forecast is "the expected output where half the time you will see energy output that's higher than the P50 level, and half the time you will see output that is lower, recognizing that wind generation is variable and nonconstant." Link, Tr. at 150:1-7.

86 Mitchell, Tr. at 214:19-21.

87 Mullins, Exh. BGM-1CT at 23 (Table 2). The resources with historical data are: Dunlap I, Glenrock I, Glenrock III, High Plains, McFadden Ridge, Rolling Hills, Seven Mile Hill I, Seven Mile Hill II, Goodnoe Hills, Leaning Juniper, Marengo I, and Marengo II.

88 Mullins, Exh. BGM-1CT at 32:1-22.

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production, asserting "[w]ind forecasts dependent on 48 months of already-curtailed historical generation will overstate what actually can be delivered." On its face, however, this assertion is false because the 48-month average represents the "average actual production of the wind facility,"[89] inclusive of curtailments.[90] PacifiCorp's newly identified "systemic" and "compounding" issues with its wind forecasting method – issues that have never been raised before to AWEC's knowledge – are red herrings that go well beyond the scope of Bench Request 02 and are designed to unnecessarily complicate a straightforward issue. As Mr. Mullins explained, his recommended modeling approach "was subject to the same transmission constraints as PacifiCorp uses."[91] Just like Popeye, the 48-month average is what it is, regardless of ancillary circumstances.

36 Meanwhile, for the other resources with less than four years of historical data, PacifiCorp claims that Mr. Mullins' use of the P50 forecast is misleading because these forecasts are allegedly "not used by the Company … as the basis for economic justification of wind investments."[92] PacifiCorp does not, however, provide the capacity factors it supposedly did use as the basis for economic justification of wind resources. Moreover, the difference between the capacity factor for P50 resources input into Aurora compared with the output capacity factor is in line with, or even less than, the difference for resources with historical data.[93] For example, resources with historical data like Glenrock I, Glenrock III, High Plains, and McFadden Ridge, all have capacity factor differentials of approximately [redacted]% or higher. By contrast, P50 resources like Ekola Flats, Foote Creek, and Rock Creek all have capacity factor differentials ranging

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89 Mitchell, Tr. at 213:4-6.
90 Mullins, Exh. BGM-1CT at 32:1-22.
91 *Id.* at 34:12-14.
92 Mitchell, Exh. RJM-13CT at 61:12-13.
93 Mullins, Exh. BGM-1CT at 23 (Confidential Table 2).

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between [redacted]% and [redacted]%. Thus, the P50 forecast is not driving the difference between input and output capacity factors.

37 Moreover, the Company's testimony regarding wind curtailments is either factually incorrect or misleading. Mr. Mullins notes that the 21.1% reduction in wind generation as an Aurora output is substantially higher than the actual curtailments PacifiCorp's wind resources have experienced through the Energy Imbalance Market ("EIM").[94] Mr. Mitchell testifies that this is "an apples-to-oranges comparison."[95] He claims that curtailments that occur through the EIM "represent only a tiny fraction of the picture" and do not include "reliability-based curtailments that the Company must execute in its role as the Balancing Authority", and also that "[t]he vast majority of curtailment happens at [the] day-ahead planning stage in Aurora, where we schedule our resources based on forecasted wind and known transmission limits."[96] These statements, however, are directly contradicted by the other evidence PacifiCorp provided in this case. As PacifiCorp has plainly stated, it "does not expect 21 percent of PacifiCorp's total wind generation will actually be curtailed in 2026."[97] Further, in response to AWEC Data Request 56, PacifiCorp stated in no uncertain terms that:

> PacifiCorp *does not initiate wind curtailments in the day-ahead planning horizon. All physical curtailment directives* – i.e., instructions to actually reduce turbine output – *occur in real time* (during the operating day), not as part of the day-ahead schedule. In day-ahead or hour-ahead operations, the Company may *forecast* lower output from wind projects in anticipation of transmission constraints, and adjust base schedules accordingly, *but it does not send binding curtailment orders to wind plants in the day-ahead horizon*. Therefore, *there were no wind curtailments initiated in the "day-ahead set-up"* to record or report for 2019 through 2024.[98]

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94 Mullins, Exh. BGM-1CT at 29:19-30:10.
95 Mitchell, Exh. RJM-13CT at 58:7.
96 *Id.* at 58:15-60:5.
97 Exh. RJM-25X (PacifiCorp's Resp. to AWEC DR 73) (emphasis in original).
98 Exh. RJM-19X (emphasis added).

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PacifiCorp also confirmed that "[a]ll quantifiable curtailment values were included in PacifiCorp's response to AWEC Data Request 009,"[99] which Mr. Mullins relied upon for his analysis. Therefore, contrary to Mr. Mitchell's testimony that the "vast majority of curtailment happens at [the] day-ahead planning stage in Aurora," in actual operations there are no such curtailments. While the Company may *forecast* lower wind production in the day-ahead setup, the actual production, and actual curtailments, are dictated by the EIM.

38 This conclusion is further supported by Company Witness Link's testimony on the Gateway South Transmission line. In Oregon, Mr. Link testified that "[redacted] percent of PacifiCorp's entire Wyoming wind fleet was curtailed in various hours before Gateway South came online, [and] only [redacted] percent has been curtailed after."[100] Mr. Link confirmed that these same benefits from Gateway South inure to Washington.[101] He also confirmed that he relied on the same data Mr. Mullins relied on when evaluating the level of PacifiCorp's wind curtailments in actual operations,[102] and that he did not consider any curtailments that occur as part of the day-ahead setup.[103] If such curtailments occurred – which, as demonstrated above, they do not – it would stand to reason that PacifiCorp would emphasize Gateway South's ability to reduce these curtailments as well, if Mr. Mitchell were correct that they represent the "vast majority" of curtailments.[104]

39 Finally, even if some wind curtailments continue to occur through the EIM now that Gateway South is in service, from a power cost forecasting perspective, this is irrelevant. This is

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99 Exh. RJM-18X (PacifiCorp's Resp. to AWEC DR 55).
100 Exh. RTL-18CX at 5:5-7.
101 Link, Tr. at 144:11-25.
102 Exh. RTL-17X.
103 Link, Tr. at 146:21-148:9.
104 Mitchell, Exh. RJM-13CT at 58:15.

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because, as Mr. Mullins points out, "[w]hen a wind plant is instructed to curtail output from the WEIM, the market provides replacement energy in the form of imbalance energy."[105] PacifiCorp confirmed this. Despite claiming that Mr. Mullins' "statement is factually incorrect," Mr. Mitchell testified that, when a curtailment occurs through the EIM, the "settlement process is designed to be a financial wash" and "there is **no net revenue received or net cost paid** by the utility."[106] Thus, Mr. Mullins' point that "PacifiCorp is not harmed economically as a result of the historical WEIM curtailments" remains valid and demonstrates that any wind curtailments that occur in actual operations do not impact NPC.[107]

40 For all of these reasons, the Commission should require PacifiCorp to model its wind resources such that the generation from these resources as an output from the model matches the generation that is input into the model. With respect to wind resources for which the capacity factor is derived based on historical data, this approach captures PacifiCorp's actual experience with these resources.

2. <u>The Commission should reject PacifiCorp's new adjustment to model forward hedging transactions.</u>

41 In this docket, PacifiCorp has proposed to model hedging transactions that it will make in the future. This is a new adjustment, at least in the context of power cost forecasting – PacifiCorp Witness Mitchell clarified at the hearing that PacifiCorp includes the NPC impact of hedges it has already executed in its compliance filing, which in this case will represent approximately 70% to 80% of the hedges it modeled in its opening testimony.[108] Therefore, as a threshold matter, the Commission should reject PacifiCorp's modeling change because it is

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105 Mullins, Exh. BGM-1CT at 30:12-13.
106 Mitchell, Exh. RJM-13CT at 60:12-16 (emphasis in original).
107 Mullins, Exh. BGM-1CT at 31:11.
108 Mitchell, Tr. at 222:14-23.

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unnecessary. To the extent it is a valid adjustment – and for the reasons discussed by Mr. Mullins and briefed below, it is not – its effects will be largely captured in the Company's compliance filing at the end of this case.

42 The premise behind PacifiCorp's forward hedging adjustment is that Aurora has perfect foresight and is able to transact in any amount for any duration to fill a need, whereas in reality, the Company is constrained by the market to purchasing volumes in 25 MW increments over a quarterly period.[109] This requires PacifiCorp to then resell excess power in the day-ahead market.[110] PacifiCorp alleges that this need to resell excess power results in a transaction cost that its modeling change is intended to capture.[111] Although PacifiCorp testifies that this transaction cost results in only a "slight loss" to the Company,[112] its modeling change increased NPC by nearly $23 million in its initial filing, equivalent to nearly 12% of Washington's entire NPC.[113]

43 If PacifiCorp actually incurred such a significant cost that was not otherwise being accounted for, it is surprising that the Company only discovered it now. Alternatively, if PacifiCorp's NPC compliance filings were capturing most of this cost, one would expect that there would be an unambiguous trend in those compliance filings resulting in NPC increases relative to the Company's initial filing. Instead, these filings show some increases and some decreases without any definitive trend either way.[114] This suggests that the cost PacifiCorp identifies does not exist, or is already being recovered through other means.

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109 Mitchell, Exh. RJM-13CT at 20:8-21:11.
110 *Id.*
111 *Id.* at 45:13-46:9.
112 *Id.* at 47:4-5.
113 Mitchell, Exh. RJM-1CT at 3 n. 2 & 29:4.
114 Docket No. UE-230172, PacifiCorp Rate Year 2 Compliance Filing (Mar. 7, 2025) (showing NPC decrease from approved rates); Docket No. UE-230172, PacifiCorp Rate Year 1 Compliance Filing at 3 (Mar. 26,

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44 PacifiCorp demonstrates the validity of the alleged transaction cost through use of an analogy to a crate of apples, where a purchaser buys substantially more apples that she needs to obtain a stable price and then resells the excess to a local grocer at a necessarily lower price than she paid the farmer.[115] This analogy, however, assumes that the market price for apples remains static even over the months that pass between the purchase and sale, as occurs with PacifiCorp's hedges when it buys blocks of power months ahead of time and resells the excess in the day-ahead market. Clearly the market price will not be static between these two periods and, to the extent it has increased since PacifiCorp made the hedge, the Company will not experience a loss in the sale of excess power at all. This is why, as Mr. Mullins discusses, both the hedging price and the spot market price are based on the Official Forward Price Curve, and consequently, "in terms of hedging costs or benefits for the hypothetical contracts, there is [no cost], because the spot market prices and hedging prices are the same."[116]

45 Furthermore, the "transaction cost" that PacifiCorp speaks of, to the extent there is one, is already captured by the Day-Ahead/Real-Time ("DA/RT") adjustment.[117] Mr. Mitchell claims that the forward hedging cost is distinct from the cost captured by the DA/RT adjustment because forward market transactions are executed months ahead of time, while the DA/RT adjustment is designed to capture costs incurred in the day-ahead and real-time markets.[118] This, however, is a misleading distinction. As Mr. Mitchell states later in his testimony, and as he reiterated at the hearing, the excess energy PacifiCorp does not need from its forward hedge

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2024) (showing NPC decrease from approved rates); Docket No. UE-210402, PacifiCorp Compliance Filing (Apr. 15, 2022) (showing NPC increase from filed rates).

115 Mitchell, Exh. RJM-13CT at 35:6-18.

116 Mullins, Exh. BGM-1CT at 54:12-14.

117 *Id.* at 55:11-57:4.

118 Mitchell, RJM-13CT at 40:2-41:17.

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transactions is sold "back to the market *in the day-ahead timeframe*."[119] Thus, it is in the day-ahead market when the transaction cost, if there is one, is incurred, which is precisely what the DA/RT adjustment already captures. For this reason, PacifiCorp's position that the DA/RT adjustment is unrelated to its forward hedging adjustment because the former addresses "the need for *continuous, hourly balancing transactions* … to true-up our position" and the latter addresses "forward market transactions" is a red herring.[120] The transaction *cost* is not incurred until the excess power is sold – in the day-ahead market, not when the forward market transaction is entered into.

46 For all of these reasons, the Commission should reject PacifiCorp's forward hedging adjustment. Not only is it evidentiarily unfounded, it is unnecessary because it is already captured by the DA/RT adjustment; and even if it isn't, this cost will be largely accounted for in the Company's compliance filing.

3. PacifiCorp has failed to carry its burden of proof to support its "Non-Precedential Modeling Changes."

47 In a section of his Direct Testimony titled "Routine Updates," Mr. Mitchell testifies that PacifiCorp has included "[a]ll non-precedential modeling improvements from the 2023 [general rate case]."[121] Although not stated in his Direct Testimony, these "non-precedential" changes relate to modifications to the DA/RT adjustment and market capacity limits ("Market Caps") and increase NPC by nearly $10 million.

48 PacifiCorp's change to the DA/RT adjustment modifies the volume component of this adjustment and is identical to the one PacifiCorp proposed in its 2023 general rate case that the

119 *Id.* at 47:3-4 (emphasis added); Mitchell, Tr. at 167:20-24.
120 *Id.* at 44:15-18 (emphasis in original).
121 Mitchell, Exh. RJM-1CT at 35: 10-17.

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Commission rejected.[122] That rejection was based in part on the Commission's finding that PacifiCorp provided "limited evidence on the DA/RT adjustment" and that its change to the volume component "was insufficiently explained."[123] PacifiCorp has provided no new evidence in this case to supplement the record on this issue and, therefore, the Company's adjustment should be rejected on the same grounds.

49 Regardless, PacifiCorp's change to the volume component of the DA/RT adjustment is unsound modeling. It is important to recall that the DA/RT adjustment itself is an outboard adjustment to the Aurora model – it is not a component of the model itself but is added in a spreadsheet after the model runs.[124] This means it does not have the same level of validation that the Aurora model itself has. PacifiCorp asserts that the volume component of the DA/RT adjustment must, by definition, result in a cost and that it was not yielding this result due to "unusual market conditions reflected in the historical data …."[125] It is, however, perhaps not surprising that unusual market conditions would yield an unusual result – that does not by itself demonstrate that the volume component of the DA/RT adjustment is broken. Furthermore, even if this did demonstrate that a problem exists with the DA/RT adjustment, the answer should not be to modify a single component of it in a one-sided manner, but to undertake a holistic review of the adjustment itself to understand how the adjustment could produce what PacifiCorp considers to be "a logical absurdity."[126] PacifiCorp did not do this; instead it simply tweaked a

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122 *WUTC v. PacifiCorp d/b/a Pacific Power & Light Co.*, Docket Nos. UE-230172 and UE-210852 (C*onsolidated*), Orders 08/06 at ¶ 311 (Mar. 19, 2024).
123 *Id.*
124 Exh. RJM-22X at 2, subpart b.
125 Mitchell, Exh. RJM-13CT at 75:4-8.
126 *Id*. at 75:9.

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single component of the adjustment to yield the result it wanted. This is not sound modeling and does not provide a solid evidentiary foundation for PacifiCorp's change.

50 With respect to market caps, AWEC objected to PacifiCorp's decision to apply market caps to historically liquid markets such as Mid-Columbia ("Mid-C") and Palo Verde, which PacifiCorp did not assign capacity limits to in the past.[127] AWEC also objected to PacifiCorp's methodology for market caps, including its proposal to exclude the sale of structure products from its historical averaging calculation.[128] On rebuttal, PacifiCorp argues that its decision to apply market caps to historically liquid hubs is justified because the Western Interconnect is more capacity constrained today than it has been.[129] PacifiCorp also argues that excluding structured products is necessary to avoid double-counting given its new approach to modeling forward market transactions, which AWEC also opposes, as discussed above.

51 While it may be the case that the Mid-C and Palo Verde markets are less liquid than they historically have been, this does not alone justify the modeling approach PacifiCorp uses for market caps. As Mr. Mullins explained, this approach "sets the cap at the average" of sales at a market hub.[130] This means that, while in practice PacifiCorp's sales at a hub will sometimes exceed the average and sometimes fall below the average, establishing a cap at the average means that, for purposes of power cost modeling, PacifiCorp's sales at a market hub can never exceed the average.[131] This by definition results in lower modeled sales than PacifiCorp will experience in actual operations. Accordingly, even if it is reasonable for PacifiCorp to model

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127 Mullins, Exh. BGM-1CT at 61:13-14.
128 *Id.* at 61:20-62:1.
129 Mitchell, Exh. RJM-13CT at 78:20-79:19.
130 Mullins, Tr. at 466:21-22.
131 *Id.* at 466:22-467:6.

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some level of cap on market sales at Mid-C and Palo Verde, the cap it has modeled, as with the cap on other market hubs, is unreasonable and should be rejected.

4. The Commission should remove the nodal pricing model fee from NPC.

52 In its initial filing, PacifiCorp included approximately $700,000[132] in costs associated with fees paid to the California Independent System Operator ("CAISO") for a nodal pricing model that was to be used both for actual system scheduling and to allocate system power costs based on nodal pricing in a system allocation methodology that was to succeed the 2020 Protocol.[133] AWEC challenged these costs, arguing that the nodal pricing model serves neither of the purposes for which it was intended. Given that Multi-State Process discussions broke down and no agreement was reached on a protocol to succeed the 2020 Protocol, the nodal pricing model is not used for power cost allocation.

53 In Rebuttal Testimony, while PacifiCorp did not dispute that the nodal pricing model is not used for power cost allocation, it did dispute that it was not used for system scheduling.[134] Notwithstanding, the Company agreed that the costs of the nodal pricing model should be removed from customer rates as of May 1, 2026, the date PacifiCorp is scheduled to join the Extended Day-Ahead Market ("EDAM"), at which point the nodal pricing model will become superfluous.[135]

54 Despite the Company's agreement to remove a portion of the nodal pricing model fees from its NPC forecast in this case, AWEC continues to recommend that the entire cost of the nodal pricing model be removed from rates, as it is not used and useful for customers.

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132 Mullins, Exh. BGM-1CT at 50:18-21.
133 *Id.* at 46:14-47:15.
134 Mitchell, Exh. RJM-13CT at 84:1-88:13.
135 *Id.* at 88:20-89:1.

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PacifiCorp claims that there is value in the nodal pricing model as a check on the actual tool the Company uses in the day-ahead setup, the primary internal optimization model ("PCI").[136] Mr. Mitchell characterizes this check as a "crucial step" that involves an "expert, qualitative review" from PacifiCorp's traders that results in a "refined plan" for the Company's real-time operators on the day of operations.[137] In discovery, however, PacifiCorp could not identify when the nodal pricing model's outputs differed from the PCI's outputs,[138] nor could it identify any instance in which PacifiCorp selected the nodal pricing model's outputs over the PCI's.[139] Indeed, because "the [nodal pricing model] results are published after 1:00 pm (Pacific), it is the PCI model that is used for PacifiCorp's day-ahead setup."[140] Thus, it is not even possible for PacifiCorp's traders to compare the nodal pricing model with the PCI to establish a "refined plan."

55 PacifiCorp also claims that the nodal pricing model has served as an effective "flight simulator" for the Company's participation in the EDAM.[141] That claim, however, is effectively impossible to test because PacifiCorp has not entered the EDAM yet. Other utilities are planning to join the EDAM and do not appear to see the need to use the CAISO's nodal pricing model as a test case for this new market before joining. There is simply no demonstrable value to customers from the nodal pricing model and it should be excluded in its entirety from Washington rates.

5. <u>AWEC accepts PacifiCorp's proposal on rates from the BP-26 rate case and the production tax credit rate</u>

56 In testimony, AWEC recommended that PacifiCorp update its rates to incorporate new transmission rates from the Bonneville Power Administration's ("BPA") BP-26 rate case, which

136 *Id.* at 85:4-12.
137 *Id.* at 85:4-15.
138 Exh. RJM-26X.
139 Exh. RJM-27X
140 *Id.*
141 Mitchell, Exh. 87:17-20.

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results in an increase to those rates, as well as a higher production tax credit ("PTC") rate for wind facilities.[142] In response, PacifiCorp opposed AWEC's proposal to update BPA rates on the basis that it fell outside of the scope of compliance items, and partially accepted AWEC's recommendation on the PTC rate for all wind facilities other than those placed in service between December 31, 2021 and January 1, 2025.[143] AWEC does not oppose PacifiCorp's rebuttal position on these issues.

IV. CONCLUSION

57 For the foregoing reasons, AWEC recommends that the Commission decline to approve the Washington 2026 Protocol in this proceeding, although review of generation-specific allocation components of the Washington 2026 Protocol is appropriately within the scope of this docket. With respect to these allocation items, the Commission should: (1) approve PacifiCorp's reassignment of Chehalis to Washington; (2) reject a continued allocation of JB 1&2 to Washington, or replace that allocation with an allocation of Hermiston; (3) reject the increased allocation of Rolling Hills unless the Commission also adopts AWEC's adjustment to wind curtailments; and (4) approve PacifiCorp's move to fixed generation factors. With respect to remaining disputed NPC issues, the Commission should: (1) adopt AWEC's adjustment to modeled wind curtailments; (2) reject PacifiCorp's new proposal to model forward hedging transactions; (3) reject PacifiCorp's "non-precedential modeling changes" related to the DA/RT adjustment and Market Caps; and (4) remove the nodal pricing model fee entirely from rates.

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142 Mullins, Exh. BGM-1CT at 45:8-46:8, 77:4-80:10.
143 Mitchell, Exh. RJM-13CT at 120:3-123:9.

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Dated this 29th day of October, 2025.

Respectfully submitted,

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