Exh. JDW-1Tr
Docket UE-250224
Witness: John D. Wilson

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**

TESTIMONY OF

JOHN D. WILSON

ON BEHALF OF STAFF OF
WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION

PacifiCorp's 2025 Power Cost Only Rate Case

August 20, 2025

Revised September 5, 2025

TABLE OF CONTENTS

LIST OF EXHIBITS

Exh. JDW-24	PacifiCorp Response to Staff Data Request No. 73
Exh. JDW-25C	Confidential Attachment to PacifiCorp's Revised Response to Public Counsel DR 102, EIM Forecast
Exh. JDW-26	PacifiCorp Response to Public Counsel Informal Data Request No. 71
Exh. JDW-27	PacifiCorp Response to Staff Data Request No. 72
Exh. JDW-28	PacifiCorp Response to Staff Data Request No. 73
Exh. JDW-29	PacifiCorp Response to Public Counsel Informal DR No. 134
Exh. JDW-30	PacifiCorp Response to Public Counsel Informal DR No. 134, First Supplemental
Exh. JDW-31	Direct Testimony and Exhibits of Cindy A. Crane, dated 8/6/25, ID PAC-E-25-14
Exh. JDW-32	Direct Testimony and Exhibits of Joelle R. Steward, dated 8/6/25, ID PAC-E-25-14

I. INTRODUCTION

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

A. My name is John D. Wilson. I am Vice President at Grid Strategies, LLC. Grid Strategies is based in the Washington, DC area, although my office is in Lexington, KY.

Q. Please state your qualifications to provide testimony in this proceeding.

A. I received a BA degree from Rice University in 1990, with majors in physics and history, and a Master of Public Policy degree from the Harvard Kennedy School of Government, with an emphasis in energy and environmental policy, and economic and analytic methods.

Since 2019, I have been a consultant, first, at Resource Insight, Inc., and now at Grid Strategies, LLC. Previously, I was deputy director of regulatory policy at the Southern Alliance for Clean Energy (SACE) for more than twelve years, where I was the senior staff member responsible for SACE's utility regulatory research and advocacy, as well as energy resource analysis. I engaged with southeastern utilities through regulatory proceedings, formal workgroups, informal consultations, and research-driven advocacy.

My work has considered, among other things, the cost-effectiveness of prospective new electric generation plants and transmission lines, retrospective review of generation-planning decisions, conservation program design, ratemaking and cost recovery for utility efficiency programs, allocation of costs of service

between rate classes and jurisdictions, design of retail rates, and performance-based ratemaking for electric utilities.

My professional qualifications are further summarized in Exhibit JDW-2.

Q. Have you testified before the Washington Utilities and Transportation Commission (Commission)?

A. Yes. I testified concerning power costs on behalf of Commission Staff (Staff) in PacifiCorp's 2023 general rate case, Docket UE-230172, PacifiCorp's 2022 power cost adjustment mechanism annual report, Docket UE-230482, Avista's 2024 general rate case, Dockets UE-20006 & UG-240007, and Puget Sound Energy's general rate case, Dockets UE-240004 & UG-240005.

Q. Have you testified before other commissions?

A. Yes. I have testified more than seventy times before utility regulators in eleven U.S. states and Nova Scotia and appeared numerous additional times before various regulatory and legislative bodies. Specifically, I have examined utility rates in many of those proceedings, testifying on cost-of-service and rate design issues in cases related to at least six utilities and supporting testimony or comments (for public, unregulated utilities) for many others.

Q. Why has PacifiCorp filed this Power Cost Only Rate Case (PCORC)?

A. The minimum scope of this PCORC is set out in two orders. In Order 09/07 in PacifiCorp's 2023 General Rate Case, the Commission ordered that,

> PacifiCorp should be required to file a PCORC by April 1, 2025, with a rate effective date of January 1, 2026, to remove coal-fired resources from rates. As AWEC witness Mullins explains, removing coalfired resources from rates is likely to have a significant effect on NPC, and it would be appropriate to consider other revenue-requirement elements that may offset increases to NPC. A simple NPC update, however, would not provide a sufficient opportunity for the parties or the Commission to consider these issues.[1]

And, in Order 07 in PacifiCorp's 2022 PCAM proceeding, the Commission found that,

> Washington ratepayers are disproportionately bearing the costs of rising prices of gas and electricity on the wholesale market, based on the Company's current allocation structure. Furthermore, we note and recall that the Commission has repeatedly encouraged PacifiCorp to build energy resources in its Western balancing authority, which may have provided some cost allocation relief to Washington ratepayers, in the present case. [2]

The Commission proceeded to order that,

> [I]n its next rate case filing in 2025, the Commission requires the Company to justify the continued application of the WIJAM and provide an alternative for cost allocation more beneficial to Washington ratepayers.[3]

> Also related to PacifiCorp's proposal, in that same Order the Commission stated that,

> With regard to hedging, we conclude that the adjustments proposed by PacifiCorp weigh more in favor of the public interest than those proposed by AWEC, and better balance the interests of the Company and the ratepayers. Additionally, we observe that the Company claims that it hedges for gas and electricity holistically in its system. If such is the case, Washington ratepayers need assurance that they are receiving a fair share of allocated benefits through PacifiCorp's hedging system.[4]

---

[1] *Wash. Utils. Transp. Comm'n v. PacifiCorp d/b/a Pacific Power & Light Company*, Dockets UE-230172 & UE-210852 (Consolidated), Order 09/07 at 5 ¶ 14 (May 16, 2024).
[2] *Matter of PacifiCorp d/b/a Pacific Power & Light Company, 2022 Power Cost Adjustment Mechanism Annual Report*, Docket UE-230482, Order 07 at 4 ¶ 17, 29 ¶ 111 (October 30, 2024).
[3] *Id*. at 4 ¶ 17.
[4] *Id.* at 5 ¶ 18.

The Commission then ordered a dispatch practice audit, which has not been submitted in this proceeding. However, PacifiCorp's proposal includes a "Washington book" which may be viewed as responsive to the Commission's findings in the above-quoted Order 07.

Finally, the Commission also ordered an analysis of market positions, with the possibility of PCAM cost recovery disallowances if PacifiCorp's approach "no longer provides economic benefit to Washington ratepayers."[5]

Q. What is PacifiCorp's request for cost recovery?

A. PacifiCorp proposes a $33.9 million increase in its revenue requirement, or 7.9%.

Table 1: Proposed PCORC Rate Change Summary[6]

Type of Change	$000 Amount
Non-NPC Base Rates	21,187
NPC Base Rates	16,291
PTC Tracker	(1,393)
Non-NPC Coal Cost Tracker	(2,174)
Total	**33,911**

Q. What is the purpose of your testimony in this proceeding?

A. I am presenting my review of PacifiCorp's power cost forecast for rate years 2026 and 2027, as presented in the testimony of Ramon J. Mitchell in RJM-1T, the reasonableness of PacifiCorp's proposed 2026 Washington Protocol and changes to its hedging practices, as presented in the testimonies of Joelle R. Steward in JRS-1T

[5] *Id.* at 36-37 ¶ 137-138.
[6] Cheung, Exh. SLC-1T, at 3.

and Rick T. Link in RTL-1T, and the reasonableness of PacifiCorp's proposed revenue requirement as presented in the testimony of Sherona L. Cheung in SLC-1T.

Q. Have you prepared exhibits in support of your testimony?

A. Yes. I sponsor Exh. JDW-2 through Exh. JDW-32. The information contained in these exhibits is correct to the best of my knowledge and belief.

II. RECOMMENDATIONS AND SUMMARY

Q. Please summarize your testimony.

A. I am generally supportive of PacifiCorp's proposal to shift to a Washington-specific resource portfolio. However, I recommend that the commission reject PacifiCorp's request to approve non-NPC adjustments in this PCORC, and instead authorize PacifiCorp to accumulate those costs, subject to limitations against double-recovery, for recovery in the next rate case.

With respect to the specific changes in cost allocation, I am generally supportive of changes to allocation factors, while discussing some issues with PacifiCorp's proposals for the SG-F and SO factors. I am also generally supportive of the Washington-specific generation plant reassignments, except for limited concerns about the Rolling Hills wind plant.

With respect to PacifiCorp's changes to modeling of hedging and market transaction costs, I have several concerns. For some of my concerns, I recommend PacifiCorp be required to provide informational filings in the coming year and

further analysis in its next rate case. My most important recommendation is that the approximately $23 million increase in NPCs associated with its proposed hedging and market transaction costs should be rejected.

I also discuss my views on PacifiCorp's WEIM benefits method (Section VII), its trackers (Section VIII), and its market position analysis (Section IX).

Q. Why are you supportive of PacifiCorp's proposal to shift to a Washington-specific resource portfolio?

A. As discussed in Section III, I generally concur with PacifiCorp's proposal as it is better aligned with Washington benefits than the Washington Inter-Jurisdictional Allocation Methodology (WIJAM). Specific recommendations made in this testimony are intended to improve on PacifiCorp's proposal, recognizing that it has implications not only for power costs but also for capital costs and other expenses.

I also note that PacifiCorp's proposal should be updated to account for recent changes in Washington law by HB 1329 (see Section III).

Q. Why do you recommend that the Commission reject PacifiCorp's request to approve non-NPC adjustments in this PCORC?

A. The PCORC is not an appropriate or well-timed proceeding to change non-NPC rates for Washington customers (see Section IV), other than those associated with the coal cost tracker (see Section VIII). As an opening point, I would expect PacifiCorp to provide a very strong justification to include non-NPCs in a Power Cost Only Rate

Case. But it has not done so, and I believe that doing so is neither in customers' interests nor consistent with good regulatory practice.

First, PacifiCorp does not expect to implement the revised inter-jurisdictional protocol in other jurisdictions prior to 2026. Accordingly, making this change immediately would risk temporary double-recovery by PacifiCorp across its jurisdictions because the timing of the changes is not coordinated with those other jurisdictions.

Second, the inclusion of non-NPC costs in this PCORC could be seen as violating the single-issue ratemaking principle. Making upward revisions to PacifiCorp's base rates without the opportunity to identify offsetting downward revisions in test year non-NPC costs is fundamentally unfair to customers.

These concerns can be addressed, in a manner that is fair to PacifiCorp, by authorizing PacifiCorp to accumulate any under-recovery of non-NPC costs from Washington customers in a deferral account for review and recovery in the next rate case, as discussed more fully in Section IV.

Q. Please explain your support for PacifiCorp's proposal to adopt the SG-F allocation factor.

A. My support for PacifiCorp's proposal to move from dynamic allocation factors (SG) to fixed allocation factors (SG-F) is conditioned with three changes to its proposal, as discussed in Section V.

First, the SG-F allocation factor should not be fixed indefinitely. Instead, it should be updated in each GRC or PCORC, unless the GRC or PCORC is filed

within 30 months of the most recent update of the SG-F allocation factor. This will avoid making SG-F a "dynamic" rate while ensuring periodic adjustments to reflect changing system conditions.

Second, the weighting of the SG-F allocation factor (system demand by 75% and system energy by 25%) appears to be arbitrary and PacifiCorp did not provide any conceptual justification of the weighting in its discovery response.[7] I recommend using the system load factor method as an industry-accepted method (such as in the average and excess method) for classifying G&T costs to energy and demand. PacifiCorp's system load factor is about 67%, which would result in classifying about 67% of SG-F costs to energy and 33% to demand.[8]

Third, given that the "portfolio" created by the Washington 2026 Protocol is a direct and important input into the annual Clean Energy Implementation Plan (CEIP) update, which may occur between rate cases, the shift to an SG-F allocation factor requires that there be a clear assignment of allocation factors not only for existing generation, but for new and planned generation. The proposed Protocol should be revised to default all non-emitting resources to SG-F, with project-specific situs or other allocation factors assigned where justified by jurisdictional funding. This recommendation has no effect on the allocation factors assigned in this PCORC – it would simply provide greater clarity for the future.

[7] Wilson, Exh. JDW-4, at (c).
[8] Calculated from Wilson, Exh. JDW-15C, tab Modified Factors 2024.

Q. Why do you recommend rejecting the approximately $23 million increase in NPCs associated with PacifiCorp's proposed hedging and market transaction costs?

A. PacifiCorp's proposal, as discussed in Section VI.B, is inadequately supported and fails the "known and measurable" test. Furthermore, it does not appear to be aligned with its proposal for a "Washington book" for hedging.

III. ADOPTION OF THE 2026 WASHINGTON PROTOCOL

Q. Please summarize the Washington 2026 Protocol.

A. PacifiCorp is proposing to replace the current cost allocation policy, the Washington Inter-Jurisdictional Allocation Methodology (WIJAM) with the Washington 2026 Protocol. PacifiCorp's proposal to revise its jurisdictional cost allocation policy was prompted by the expiration of the 2020 Protocol, from which the WIJAM was derived, and Washington's exit from coal.

Compared to the WIJAM, the Washington 2026 Protocol changes the allocation of certain existing generation resources consistent with Washington state policy, shifts to fixed rather than dynamic allocation factors, and proposes a situs assignment of new resources identified for Washington after April 1, 2025.

PacifiCorp has evaluated the Washington 2026 Protocol's generation portfolio to determine whether it provides quantifiable or indirect benefits to Washington from the perspectives of resource adequacy and energy needs.

Q. Is PacifiCorp submitting similar proposals in its other jurisdictions?

A. Yes. In early August, PacifiCorp submitted applications for approval of its 2026 Protocol in Idaho, Oregon, Utah, and Wyoming.[9] Presumably, a similar application in California is forthcoming before September 1, 2025.[10]

PacifiCorp explains that its 2026 Protocol in the other five jurisdictions will be served by what it refers to as its "Five-State Portfolio." PacifiCorp further anticipates filing a further "Phase 2" revision to the 2026 Protocol in advance of rate filings effective January 1, 2030.[11] In addition to Washington's legislative deadlines, PacifiCorp faces several other upcoming legal obligations, including:

- Wyoming House Bill (HB) 200 (2020) requires that a portion of load in the state to be served by carbon capture technology by July 1, 2033;
- Wyoming HB 166 (2021) establishes a rebuttable presumption against coal or gas fueled plant retirement;
- Oregon's HB 2021 (2021) and Senate Bill (SB) 1547 (2016) set resource and emissions targets starting in 2030;
- Utah SB 224 (2024) establishes a preference for dispatchable generation; and
- Utah HB 411 (2019) allows for Utah communities to opt-in to programs to reach 100 percent renewable generation by 2030.[12]

[9] Wilson, Exh. JDW-27, at 1.
[10] Wilson, Exh. JDW-3, at (b); Wilson, Exh. JDW-9, at (c).
[11] Wilson, Exh. JDW-31, at 19.
[12] *Id.* at 11-12.

Q. Please summarize your position on PacifiCorp's proposal to shift to a Washington-specific resource portfolio.

A. PacifiCorp has generally demonstrated that the proposed changes more closely align the costs based on causation and provides benefits to Washington customers.[13] Compared to the WIJAM, PacifiCorp has enabled "dispatch of a different resource portfolio to serve Washington customers consistent with the state's energy policies."[14] In general, I concur with PacifiCorp's findings that its proposal is better aligned with Washington benefits than the WIJAM.[15]

Furthermore, the assignment of Chehalis to Washington resolves a significant policy issue regarding whether customers in other states are obligated to pay CCA costs for Chehalis. Assignment of Chehalis to Washington shifts approximately $31.1 million in CCA costs from the other five states to Washington.[16]

Q. How does the passage of HB 1329 impact this PCORC?

Under current Washington law, PacifiCorp argues that the requirement for CETA compliance would require premium-priced forward energy products.[17] However, as of May 12, 2025, HB 1329 has become law, and should result in PacifiCorp removing the 50 percent premium on supply risk hedges.

[13] *Wash. Utils. Transp. Comm'n v. PacifiCorp d/b/a Pac. Power & Light Company*, Docket UE-130043, Order 05 at 39 ¶ 94 (Dec. 4, 2013).
[14] Steward, Exh. JRS-1T, at 12-13.
[15] *See* Wilson, Exh. JDW-13 (supporting review of changes). *See also* Wilson, Exh. JDW-10C (discussion of the inter-related considerations related to WRAP, EDAM, and IRP resource adequacy).
[16] Wilson, Exh. JDW-32, at 29.
[17] Mitchell, Exh. RJM-1T, at 12.

PacifiCorp should update its proposal to remove the assumption regarding premium-priced forward energy products associated with CETA compliance.

Q. Does the Washington-specific resource portfolio match Washington customers' requirements exactly?

A. No. The Washington-specific resource portfolio will not exactly match the projected Washington energy requirements. It is certain that in each power cost forecast, Washington will end up as either net short or net long, requiring the gap to be filled by market-priced resources (or surplus sold).

I agree that PacifiCorp's proposal has substantially narrowed that gap relative to the WIJAM. In the future, PacifiCorp should strive to minimize that gap, but there should not be an unreasonable expectation that the gap will be zero. Because the forecast power resources and system requirements will always vary at least somewhat from the forecast, the size of the forecast gap is less important than the actual outcome.

IV. NON-NPC COST ADJUSTMENTS

Q. Please summarize PacifiCorp's proposal to adjust non-NPC costs in this PCORC.

A. PacifiCorp proposes a number of non-NPC cost adjustments, which total $21.2 million – about two-thirds of the total rate change.[18] The non-NPC cost adjustments

[18] Cheung, Exh. SLC-1T, at 3, Table 1.

can be subcategorized into three groups: 1) changes to allocation factors, 2) additions and removals of specific generation units, and 3) tax and interest effects resulting from other changes.

PacifiCorp proposes to adjust rates to recover the non-NPC costs (including the Temporary Coal Cost Adjustment changes) using cost-of-service study Factor 10 percentages from the 2023 general rate case.[19]

A. Legal Authority for Increase in Non-NPC Rates

Q. Does PacifiCorp identify any specific legal authority under which to reset non-NPC rates in this PCORC?

A. No. PacifiCorp has not identified any specific legal authority under which to reset non-NPC rates in this PCORC. In response to a data request, PacifiCorp stated, "PacifiCorp is unaware of any legal authority that would prevent the Company from requesting a revised allocation methodology in a power cost only rate case (PCORC)."[20] Instead, PacifiCorp's position seems to be that the proposed Washington 2026 Protocol "would be meaningless, and would not meet the requirements of CETA, without matching non-NPC costs associated with the assets used to set NPC effective January 1, 2026."[21]

[19] Lipinsky, Exh. ATL-1T, at 2.
[20] Wilson, Exh. JDW-3, at (a).
[21] *Id.*

Q. Did the Commission's order in the 2023 GRC envision an increase in non-NPC costs?

A. No. In Order 09/07 in PacifiCorp's 2023 General Rate Case, the Commission ordered that,

> PacifiCorp should be required to file a PCORC by April 1, 2025, with a rate effective date of January 1, 2026, to remove coal-fired resources from rates. As AWEC witness Mullins explains, removing coal-fired resources from rates is likely to have a significant effect on NPC, and it would be appropriate to consider other revenue-requirement elements that may offset increases to NPC. A simple NPC update, however, would not provide a sufficient opportunity for the parties or the Commission to consider these issues.[22]

In that order, the Commission did not adopt PacifiCorp's view that it should be allowed to amend its multi-year rate plan (MYRP) as an alternative to a PCORC.[23] In its argument, PacifiCorp stated that, "When [coal-fired] resources are removed from rates, it is likely that the Company's NPC will sharply increase as the Company secures alternative resources to serve its customers."[24] And later, that "resource reallocation could potentially result in lower-cost alternatives to mitigate rate impacts to Washington customers."[25] Instead of accepting PacifiCorp's views of a sharp increase to rates, the Commission's order plainly focuses on adjustments that "offset increases to NPC."

[22] *Wash. Utils. Transp. Comm'n v. PacifiCorp d/b/a Pacific Power & Light Company*, Dockets UE-230172 & UE-210852 (Consolidated), Order 09/07, at 5 ¶ 14 (May 16, 2024).
[23] *Wash. Utils. Transp. Comm'n v. PacifiCorp d/b/a Pacific Power & Light Company*, PacifiCorp's response to AWEC's Motion for Clarification, Dockets UE-230172 & UE-210852 (Consolidated), at ¶ 10-13 (April 1, 2024).
[24] *Id.* at ¶ 8 (April 1, 2024).
[25] *Id.*

B. Evaluation of Non-NPC Cost Recovery

Q. Is it reasonable for PacifiCorp to propose adjustments to non-NPC rates in this application?

A. No. The Commission's ordered PacifiCorp to file a "power-cost only" rate case, that scope should not be expanded to allow selective adjustments to base rates set in the MYRP, with the exception of the coal cost tracker, as discussed in Section VIII below.

However, PacifiCorp's request to *increase* non-NPC rates by $21.2 million in 2026 is clearly at odds with the Commission's order which expanded the PCORC scope to include "other revenue-requirement elements that may *offset increases* to NPC."[26] And furthermore, PacifiCorp did not clearly raise the possibility that it could propose an increase in non-NPC rates in its response brief, as referenced above.

Of course, the interpretation of the Commission's order is entirely up to the Commission. But I present my views on the background of this issue because there are sound regulatory reasons that the Commission is unlikely to have envisioned the scope of this proceeding to include selective increases in non-NPC costs.

[26] *Wash. Utils. Transp. Comm'n v. PacifiCorp d/b/a Pacific Power & Light Company*, Dockets UE-230172 & UE-210852 (Consolidated), Order 09/07 at 5 ¶ 14 (May 16, 2024).

Q. Why is a PCORC an inappropriate proceeding in which to adjust non-NPC costs?

A. First, adjusting non-NPC costs and rates in this manner could be viewed as violating the single-issue ratemaking principle. Generally, regulators avoid or prohibit single-issue ratemaking. As summarized in an Edison Electric Institute publication, "Regulation is designed to focus on the total net cost of service to avoid piecemeal or single-issue ratemaking. That is, regulators are generally required to review all costs included in the [total revenue requirement] to assure that the net result includes all cost increases and decreases as well as productivity changes."[27]

In other words, costs may increase in one area but decrease in other area. This is why it is inappropriate to re-examine non-NPC costs on a piecemeal basis, as PacifiCorp requests in this instance.

Second, in this instance, there is a clear risk of temporary double-recovery. Indeed, PacifiCorp acknowledges that its multi-jurisdictional cost allocation process does not guarantee that it will recover only 100% (or less).[28] PacifiCorp proposes shifting the costs of Chehalis from multi-jurisdictional cost recovery to 100% recovery in Washington rates.[29] If the non-NPC costs associated with Chehalis are placed in Washington rates, but not removed from the rates of other jurisdictions at a similar time, this will result in double-recovery of those costs.[30] It seems very likely

[27] McDermott, Karl, *Cost of Service Regulation in the Investor-Owned Electric Utility Industry*, Edison Electric Institute, 9 (June 2012), https://www.ourenergypolicy.org/wp-content/uploads/2012/09/COSR_history_final.pdf.
[28] Wilson, Exh. JDW-9, at (e).
[29] Link, Exh. RTL-1T, at 10.
[30] Similarly, PacifiCorp proposes to remove the Hermiston natural gas facility from Washington rates. However, these two changes do not exactly offset.

that approval of the $21.2 million in non-NPC costs will result in some temporary double-recovery by PacifiCorp across its jurisdictions.

Q. Is there evidence that PacifiCorp has received double-recovery for plants that it proposes to re-classify?

A. Yes. PacifiCorp provided a summary of allocation percentages for each of its generation resources in response to a data request. I have summarized the total allocation percentage for each of the five generation resources that PacifiCorp proposes to substantially re-allocate across jurisdictions in the Washington 2026 Protocol. As shown in Table 2, PacifiCorp's total allocation percentage across its six state jurisdictions and FERC[31] has been well in excess of 100% over the past six years for these units, with the exception of Rolling Hills, which is discussed in Section IV.C below.

Table 2: Total Jurisdictional Allocation Percentages[32]

	2019	2020	2021	2022	2023	2024
Chehalis	114.6%	114.2%	114.4%	114.2%	113.6%	114.2%
Colstrip	114.6%	114.2%	114.4%	114.2%	113.6%	114.2%
Hermiston	114.6%	114.2%	114.4%	114.2%	113.6%	114.2%
Jim Bridger	114.6%	114.2%	114.4%	114.2%	113.6%	114.2%
Rolling Hills	66.0%	64.7%	73.1%	73.3%	73.0%	73.9%

This evidence alone does not prove that PacifiCorp has been over- (or under-) recovering its total non-NPC plant costs for all plants over these six years. For a number of generation units, PacifiCorp has total allocation percentages less than

[31] FERC allocation is less than 0.1% for all generation units.
[32] Wilson, Exh. JDW-26.

100%, typically about 92%. (And for a number of others, the allocation percentage has been close to 100% since 2021.) Additional data would be required to calculate PacifiCorp's authorized revenue recovery for generation plant in service over all six years, which would be the basis for determining over- or under-recovery.

Q. Can you estimate how much PacifiCorp has over-recovered for any plants?

A. Yes, but only for one plant. I estimate that PacifiCorp has over-recovered an average of $~~5.8~~4.9 million per year for Chehalis. This is based on a review of data provided by PacifiCorp in response to a data request that is specific to Chehalis,[33] and similar information does not appear to be on the record for other plants.

Q. Could PacifiCorp's re-assignment of generation plants result in the total allocation percentage for most plants being approximately 100%?

A. Yes, but only when the timing of cost-allocation protocol changes is coordinated with those other jurisdictions. Until then, PacifiCorp's proposal will only result in excess revenues at the expense of Washington customers. The proposed $21.2 million increase in non-NPC rates for Washington customers will represent surplus revenue to PacifiCorp until other jurisdictions' revenue requirements are adjusted accordingly.

[33] Wilson, Exh. JDW-29, at 2-3. Wilson, Exh. JDW-30, at 1.

Q. How long will it take for PacifiCorp's other jurisdictions to adjust their generation plant revenue requirements?

A. I expect this will not occur until 2027. As noted above, in early August, PacifiCorp submitted applications for approval of its 2026 Protocol in Idaho, Oregon, Utah, and Wyoming.[34] Presumably, a similar application in California is forthcoming before September 1, 2025.[35]

None of the four 2026 Protocol applications appear to include proposals for changes in either NPC or non-NPC rates. The 2026 Protocol indicates that PacifiCorp will first apply the new jurisdictional allocation factors when filing its actual NPC in 2027, reviewing 2026 NPC.[36]

When asked for the regulatory process or authority expected to be used in each jurisdiction, PacifiCorp provided the following answer:

> While it depends on the jurisdiction and the individual processes and ratemaking mechanisms approved in that jurisdiction, PacifiCorp will generally file for an approval of a cost allocation methodology, which will then be implemented in a subsequent GRC. PacifiCorp may request deferred accounting or specific treatment in various NPC mechanisms as the transition occurs.[37]

Further, the 2026 Protocol filed by PacifiCorp in other state jurisdictions includes the provision that, "Once the 2026 Protocol is approved in a jurisdiction, the revised cost allocation factors will be implemented through rate proceedings initiated after such approval."[38]

[34] Wilson, JDW-27, at 1.
[35] Wilson, Exh. JDW-3, at (b); Wilson, Exh. JDW-9, at (c).
[36] Wilson, Exh. JDW-32, at 75.
[37] Wilson, Exh. JDW-3, at (c); Wilson, Exh. JDW-9, at (d).
[38] Wilson, Exh. JDW-32, at 68-69.

For non-NPCs, given past practice, rate adjustments in any of the other five jurisdictions are unlikely to take effect earlier than January 1, 2027, and potentially much later. This is because it appears unlikely that the 2026 Protocol will be approved in other jurisdictions until late 2026 or early 2027. Once approved in those five jurisdictions, PacifiCorp could immediately file a rate case, which would probably be no earlier than January 2026, and likely at least several months later. This leads to a likely effective rate change date no earlier than January 1, 2027.

Thus, there will be at least a one-year lag until some PacifiCorp jurisdictions adjust non-NPCs. Accordingly, it is more reasonable to postpone non-NPC rate adjustments in Washington until PacifiCorp's next GRC, which would be more closely aligned with the implementation schedule in other jurisdictions.

Q. Would it be reasonable for PacifiCorp to recover interim non-NPC costs in its next GRC?

A. Yes, provided that it is able to demonstrate no double-recovery. I recommend that the Commission authorize PacifiCorp to establish a deferral account in which it may accumulate non-NPC costs and credits that are caused by the jurisdictional rollout of updated cost-allocation proposals.

With the exception of Rolling Hills, which I will discuss in Section IV.C below, PacifiCorp is re-assigning some non-NPC costs away from Washington customers and reassigning some NPC costs to Washington customers. The proposed deferral account should be used to accumulate costs that are triggered by the

implementation of the 2026 Protocol in the rates approved for PacifiCorp's other jurisdictions.

For example, if a jurisdiction approves the 2026 Protocol and PacifiCorp determined that the combined impact of the Washington 2026 Protocol and the other jurisdiction's approved protocol is a net transfer of $5 million in annual costs to Washington customers, then it should begin accumulating that $5 million cost in the proposed deferral account when the other jurisdictions' new rates go into effect. A similar approach should be implemented where the net transfer is an annual credit.

Then, in PacifiCorp's next general rate case, the reasonableness of PacifiCorp's calculations and the overall equity of the other jurisdictions' approved cost-allocation protocols should be reviewed by the Commission.

Q. Please summarize your recommendation to the Commission on non-NPCs.

A. I recommend that the Commission reject PacifiCorp's request to approve non-NPC adjustments in this PCORC, and authorize PacifiCorp to establish a deferral account in which it may accumulate non-NPC costs and credits that are caused by the jurisdictional rollout of updated cost-allocation proposals.

Q. If the Commission allows PacifiCorp to adjust non-NPCs, do you have any specific concerns about its proposals that are not addressed elsewhere in your testimony?

A. Yes. I have concerns with PacifiCorp's proposal for the Rolling Hills Wind Plant costs and its system overhead allocation factor. These are discussed below in subsections IV.C and IV.D.

C. Increase in Rolling Hills Wind Plant Costs

Q. Please summarize PacifiCorp's proposal to allocate an additional share of the Rolling Hills Wind Plant to Washington customers.

A. PacifiCorp proposes to increase the Washington-specific allocation of the Rolling Hills Wind Plant to support CETA objectives. Specifically, PacifiCorp proposes to allocate a share of Rolling Hills' costs that PacifiCorp has been unable to recover since 2008, when the Oregon Commission disallowed costs associated with that project from Oregon customers' rates. Since the 2008 disallowance, PacifiCorp has not assigned Oregon's share (25% - 27%) of the costs of Rolling Hills to any state.[39]

Washington customers did not pay for or receive a designated share of Rolling Hills until the WIJAM was implemented in 2020.[40]

I also note that PacifiCorp admitted a Rolling Hills-related error and has supplied corrected workpapers and an update to Wilding Direct, Figure 1. For clarity, this error is not materially related to my discussion of this proposal.

[39] Wilson, Exh. JDW-17, at (a). Wilson, Exh. JDW-18C.
[40] Wilson, Exh. JDW-17, at (a).

Q. Have Washington customers been receiving surplus power from Rolling Hills for free?

A. No. PacifiCorp states that "Rolling Hills has been dispatched to serve all PacifiCorp customers."[41] Even so, this should not be interpreted to suggest that Washington customers received a portion of the unallocated Oregon share cost-free. The portion of Rolling Hills generation used for Washington net position balancing in PCAM and GRC proceedings since 2020 has been the system SG factor (about 8%), and Washington has been net short during that time. One might view Washington customers as having paid PacifiCorp for the unallocated Rolling Hills share through the net position balancing costs.

However, customers in other PacifiCorp jurisdictions have likely been receiving some of the unallocated Oregon share cost-free because they have been net short. PacifiCorp proposes to re-assign this uncompensated power that has benefitted other jurisdictions (through system dispatch) to Washington customers. PacifiCorp also proposes to begin recovering this previously-unrecovered cost from Washington customers through non-NPC rates effective immediately.

Q. Do you have concerns with PacifiCorp's Rolling Hills proposal?

[41] *Id.* at (g).

A. Yes. The project is relatively costly and subject to a higher-than-typical curtailment rate. The Commission approved the costs of Rolling Hills being included in rates as part of the update of power assigned to Washington via the 2020 Protocol.[42]

Furthermore, given its higher costs and curtailment rate, there are concerns about these costs being fair and reasonable to Washington customers. Rolling Hills is a relatively expensive resource, costing $145 per MWh.[43] Furthermore, Rolling Hills "is often the second wind resource in eastern Wyoming to be curtailed … doing so results in less loss of production tax credits."[44]

Q. Are there advantages to PacifiCorp's proposal to allocate an additional portion of Rolling Hills' costs to Washington customers?

A. Yes. As a zero-emission resource that is immediately available, for both CETA and CCA compliance purposes, PacifiCorp's proposal is advantageous.

Q. How do you balance your concerns with the advantages of the Rolling Hills proposal?

A. PacifiCorp is effectively requesting the Commission to approve (a) an expanded allocation of Rolling Hills to Washington customers (along with other changes in

[42] PacifiCorp states, "Rolling Hills wind generation costs were first approved to be reflected in Washington rates through the adoption of the Washington Inter-Jurisdictional Allocation Methodology (WIJAM) and the Washington Utilities and Transportation Commission (WUTC) approval of the 2020 Multi-State Inter-jurisdictional Cost Allocation Methodology (2020 Protocol), which is an agreement among the six states comprising PacifiCorp's service territory to collaborate in an attempt to develop a more comprehensive cost allocation methodology, in the Company's 2019 general rate case (GRC), Docket UE-191024 through Final Order 09/07/12, with rates effective January 1, 2021." Wilson, Exh. JDW-5, at (e). While this order generally approved Rolling Hills wind generation costs as part of the overall WIJAM and 2020 Protocol, it did not specifically rule on this resource or its prudence.

[43] Calculated as described in Wilson, Exh. JDW-20.

[44] Wilson, Exh. JDW-19.

resource assignment) and (b) higher cost recovery for Rolling Hills than PacifiCorp was recovering from Washington customers or, collectively, from its entire system. Given the net increase in cost recovery and the higher costs, it may be appropriate for the Commission to evaluate whether the cost of the additional project resources being assigned to Washington are fair, just, and reasonable. The relatively high cost and curtailment rate of the Oregon share of Rolling Hills suggests that the Commission *might* reasonably find that costs associated with Rolling Hills are not fair, just, and reasonable and either reject it outright (as Oregon did, on the basis of prudence) or accept it with a partial cost disallowance.

But of course the plant came into service in 2008, and prudence is usually determined based on the facts in existence when the investment was made. This view is complicated by the fact that even though it was placed in service in 2008, PacifiCorp's then-effective cost allocation method did not allocate any of its costs to Washington customers, so the Washington Commission did not evaluate Rolling Hills prudence at that time.

Considering all the circumstances in PacifiCorp's proposal, I believe it is in the interest of Washington customers to receive the proposed allocation of Rolling Hills energy. However, I do not believe it is reasonable for Washington customers to pay for Rolling Hills energy without some cost consideration to reflect the fact that it is a high-cost resource subject to high curtailment rates.

Q. What is your recommendation for providing Washington customers with some cost consideration?

A. The most straightforward approach is for the Commission to accept my proposal to reject PacifiCorp's request to adjust non-NPC rates until its next GRC. Currently, PacifiCorp states that it is providing this power (the "Oregon share") to its system with no recovery of cost. For purposes of the PCORC, it is reasonable to assign the previously-unassigned Oregon share of Rolling Hills generation to Washington for purposes of net position balancing calculations as part of PacifiCorp's 2026 Protocol proposals.

With respect to PacifiCorp's request for non-NPC cost recovery, unlike my proposal for other generating units, since PacifiCorp is not transferring costs from other utilities, there would not be a clear automatic trigger for PacifiCorp to begin accumulating costs in the proposed deferral account. I see three options:

- Wait until PacifiCorp's next GRC to include the Oregon share of Rolling Hills costs in Washington customer rates.
- The Commission could set a date certain on which PacifiCorp could begin accumulating Rolling Hills costs in the proposed deferral account, such as in two years.
- The Commission could allow PacifiCorp to proportionately increase Rolling Hills costs as other jurisdictions adopt the updated cost-allocation protocol. For example, when non-NPC jurisdictions with updated cost-allocation protocols represent 50% of load, then 50% of the proposed Rolling Hills cost would be eligible for accumulation in the proposed deferral account.

At the approved time, Washington customers would then pay for Rolling Hills at the same cost as other jurisdictions, providing PacifiCorp with a solution that is administratively simple.

Another approach the Commission could choose is to reduce the cost recovery for Rolling Hills – either by disallowing[45] cost recovery for two years or by some percentage the commission deems appropriate over the lifetime of the plant. One of these approaches would be appropriate if the Commission decides to allow adjustments to non-NPC costs. Of the two, the percentage disallowance would be slightly more complex to implement and review. I do not have a strong recommendation for one of these options over the other, as either addresses Staff's concerns.

Summarizing my position, I recommend that the Commission specifically find that PacifiCorp should include the requested energy benefits from Rolling Hills in its NPC calculations, which will positively benefit Washington customers by reducing net position balancing costs. I also recommend that the Commission find that PacifiCorp's request to include the full costs of Rolling Hills should be considered in the next GRC, along with other non-NPC costs.

Q. If the Commission rejects your recommendation to give Washington customers some cost consideration to reflect the fact that Rolling Hills is a high-cost resource subject to high curtailment rates, how should the costs be recovered?

[45] Instead of a full disallowance, allowing partial recovery now and addressing the issue of full cost recovery and prudence of the non-NPC costs associated with Rolling Hills until a later date.

A. As discussed above, I recommend against making any out-of-scope adjustments to non-NPC rates. Accordingly, if the Commission does not reduce cost recovery for Rolling Hills, PacifiCorp should be allowed to accumulate the approved costs in the proposed deferral account for review and recovery, subject to the Commission's order, in its next rate case.

D. Revision to System Overhead Allocation Factor Method

Q. Please summarize your position with respect to the System Overhead Allocation Factor.

A. PacifiCorp proposes to revise the system overhead allocation factor method (SO), resulting in a small increase for Washington. Witness Cheung explains that it is necessary to change the current SO factor because the current factor would have to be revised as a consequence of changing the jurisdictional allocation of system generation resources. While technically feasible, the current method complicates allocation of certain balances and represents a "circular formula."

Because I recommend against changing the jurisdictional allocation of system generation resources, I do not believe it is necessary for the Commission to rule on PacifiCorp's proposal for the SO factor method revision.

Nonetheless, I am generally supportive of this proposal, as the current method is overly complex. However, while PacifiCorp acknowledges that the SO will require updates as resource allocations shift over time, PacifiCorp's position on

when the SO factor would be updated is unclear.[46] It appears clearer that PacifiCorp intends to update the SO factor for its other jurisdictions in its proposed 2026 Protocol.[47] Consistent with my recommendation on the SG-F factor (see Section V.A) the SO factor should be updated in each GRC.

Thus, if the Commission rules on PacifiCorp's proposal to revise the SO factor, I recommend that the Commission modify PacifiCorp's proposal to require the SO factor be updated in each GRC and then remain static between GRCs.

E. Proposed Cost Allocation for Non-NPC Cost Recovery

Q. What is your opinion of the proposed cost allocation for non-NPC cost recovery?

A. PacifiCorp proposes to use "Factor 10," a cost allocation factor included in its 2023 GRC. PacifiCorp explains that this factor is used to allocate generation costs in the 2023 GRC.[48] This appears to be a reasonable cost-allocation method for any costs approved by the Commission for recovery between the PCORC and the next rate case.

Q. For clarity, please summarize your position on non-NPC cost recovery.

A. I am recommending that the Commission reject the full $21.2 million request for increases in non-NPC costs. If the Commission does not, I have reviewed the full

[46] Wilson, Exh. JDW-9, at (b).
[47] Wilson, Exh. JDW-32, at 77.
[48] Lipinsky, Exh. ATL-1T, at 2; Wilson, Exh. JDW-24.

non-NPC cost recovery proposal and the only two adjustments I recommend are to (a) modify PacifiCorp's proposal to require the SO factor be updated in each GRC, and then remain static between GRCs; and (b) accept the Rolling Hills energy allocation subject to either a two-year delay in cost recovery or a 10% reduction in cost recovery for the lifetime of the assets. Further, the Commission should closely review the cost allocation of non-NPC cost recovery for the period up until the next GRC.

V. CHANGE FROM DYNAMIC TO FIXED ALLOCATION FACTORS

Q. Please summarize PacifiCorp's proposal to replace the SG cost allocation factor with the SG-F allocation factor in the Washington 2026 Protocol.

A. PacifiCorp proposes to revise the system generation allocation factor method (SG) to a four-year average (SG-F), resulting in a small decrease for Washington.

Q. Is PacifiCorp's proposal reasonable?

A. Yes, generally. As with the System Overhead (SO) factor mentioned in Section IV above, I am generally supportive of the proposal to move from dynamic allocation factors to fixed allocation factors, with three key caveats.

First, the fixed allocation factors should not be fixed indefinitely, but rather periodically. I suggest that the SG-F should be updated in each GRC or PCORC,

unless the GRC or PCORC is filed within 30 months of the most recent update of the SG-F allocation factor.[49]

Second, the weighting of the SG-F allocation factor (system capacity by 75% and system energy by 25%) appears to be arbitrary and PacifiCorp did not provide any conceptual justification for the weighting in its discovery response.[50] I recommend using the system load factor method as an industry-accepted method for classifying generation and transmission costs to capacity and energy.

Third, given that the "portfolio" created by the Washington 2026 Protocol is a direct and important input into the annual Clean Energy Implementation Plan (CEIP) update, which may occur between rate cases, the shift to an SG-F allocation factor requires that there be a clear assignment of allocation factors not only for existing generation, but for new and planned generation.

A. Need for Periodic Updates to the SG-F Allocation Factor

Q. How does PacifiCorp propose to update the SG-F allocation factor going forward?

A. PacifiCorp states that the SG-F allocation factor is not intended to change over time, proposing instead to lock in and indefinitely fix it going forward.[51] PacifiCorp states that, "[t]he intent of using fixed allocation factors is to reduce uncertainty for planning purposes," and that, "Dynamic allocation factors add to the uncertainty as

[49] Since the SO factor only applies to non-NPCs, it would only need to be updated in GRCs, unless the Commission makes a practice of updating non-NPCs in PCORCs.
[50] Wilson, Exh. JDW-4, at (c).
[51] Wilson, Exh. JDW-4, at (b).

relative loads are changing across jurisdictions at potentially, a faster pace than historically observed, and may not be accurately forecasted far into the future, creating more uncertainty regarding future resource needs and CETA compliance positions."[52]

Q. Do you agree with this proposal to fix the SG-F allocation factor indefinitely?

A. No. I find the above argument unconvincing. In the context of explaining why a four-year average is a more appropriate basis for the SG-F than is a longer-term average, PacifiCorp argues that it is important to have an outcome that is "reflective of current or on-going expected conditions."[53] I agree that the use of a four-year average is an appropriate way to facilitate providing a more normalized outcome while remaining current. However, without periodic adjustments, the SG-F will not reflect future changes in the PacifiCorp system.

Q. Do you have any other concerns about indefinitely fixing the SG-F jurisdictional allocation factor for Washington?

A. Yes. First, this approach is inconsistent with the approach proposed for PacifiCorp's other five jurisdictions, where both non-fuel and NPC costs will be allocated using a dynamic system generation factor (SG5).[54] As the respective jurisdictions' load changes over time, cost allocation among the five other jurisdictions will shift to reflect the changing shares of load. But for Washington, PacifiCorp proposes that its

[52] Wilson, Exh. JDW-16.
[53] Wilson, Exh. JDW-4, at (e)(i).
[54] Wilson, Exh. JDW-32, at 70-71, 75-76.

cost allocation will not change, no matter how significant a shift in relative generation share may occur in the future. This inconsistency is inequitable, and should be resolved.

Second, this approach is also inconsistent with PacifiCorp's proposal to allocate costs associated with new large loads (customers with contract demand greater than 50 MW) to the jurisdiction in which the customer load is located. Fixing Washington's share of system costs even as generation costs may shift dramatically in other jurisdictions is inequitable.

Q. Please summarize PacifiCorp's proposal to allocate costs of new large load customers in the 2026 Protocol.

A. In its 2026 Protocol filings in four other jurisdictions, PacifiCorp has included the following provision:

> The costs associated with New Large Load that require 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).[55]

[55] Wilson, Exh. JDW-32, at 79.

Q. What is your opinion of this provision?

A. This provision is a useful clarification of PacifiCorp's jurisdictional cost allocation protocol. I recommend that it be added to the Washington 2026 Protocol.

Q. How often should the SG-F allocation factor be updated?

A. I recommend that the Commission direct PacifiCorp to update the SG-F allocation factor in each GRC or PCORC, unless the GRC or PCORC is filed within 30 months of the most recent update of the SG-F allocation factor. This avoids making SG-F a "dynamic" rate, while ensuring periodic adjustments to reflect changing system conditions.

B. Revision to SG-F Allocation Factor Weighting

Q. What, as you understand it, is the basis for the proposed weighting of the SG-F allocation factor?

A. Witness Ghosh argues that the transition to the SG-F allocation factor involves "meeting CETA obligations."[56] However, the specific weighting of the SG-F allocation factor (system capacity by 75% and system energy by 25%) appears to be arbitrary. PacifiCorp did not provide any conceptual justification of the weighting in its discovery response.[57]

[56] Ghosh, Exh. RG-1T at 7-8.
[57] Wilson, Exh. JDW-4, at (c).

Q. What would be a more appropriate approach to the weighting of the SG-F allocation factor?

A. The system load factor method is an industry-accepted method for classifying generation and transmission costs based on capacity and energy. PacifiCorp's system load factor is about 65%,[58] though, if data centers significantly impact the system, that number could increase. Under the system load factor method, 65% (rather than 25%) of the SG-F factor would be determined by Washington's share of system energy.

C. Default New Non-Emitting Resources to SG-F Allocation Factor

Q. Why is it necessary to define an allocation factor for future non-emitting resources?

A. It is notable that the "portfolio" created by the Washington 2026 Protocol is a direct and important input into the annual CEIP update, as its assumptions are used in the forecast of energy and CETA-compliant energy to serve Washington retail sales.[59] These updates may occur between rate cases. Accordingly, there needs to be a clear assignment of allocation factors for new and planned generation.

Q. What is PacifiCorp's proposed assignment of allocation factors for new and planned generation?

[58] Calculated from Wilson, Exh. JDW-15C, tab Modified Factors 2024.
[59] Wilson, Exh. JDW-13(d).

A. PacifiCorp proposes to assign new resources, "acquired for Washington after April 1, 2025, … on a situs basis to Washington unless circumstances justify a cost-sharing proposal with other states."[60] If an alternative allocation is needed, PacifiCorp would propose this "at or before a prudence review occurs for a new resource."[61]

Q. Would this approach work in every circumstance?

A. No, there are several circumstances in which this approach is not clear enough and creates an unnecessary opportunity for confusion or inconsistency.

I would understand the term situs to mean that a generation plant located in the state of Washington would have its costs and generation assigned to Washington for cost recovery and net position balancing purposes.

However, as noted above, the Washington 2026 Protocol will guide the assignment of PacifiCorp resources used in forecast of energy and CETA-compliant energy to serve Washington retail sales. Thus, if PacifiCorp issues an RFP for renewable generation to serve Washington customer load, eligible projects may be located outside of the state of Washington and thus would be situs-assigned to another state.

Another possibility is that PacifiCorp procures generation resources to serve system load. Again, for both forecast and, eventually, ratemaking purposes, there would not be a clear allocation factor under PacifiCorp's proposal.

A third possibility is a generation resource that PacifiCorp procures in an unusual opportunity, such as a multi-year contract for hydro resources in

[60] Link, Exh. RTL-2, at 3 ¶ 7.
[61] *Id.*

Washington, without clear regulatory guidance to procure the resource for Washington customers.

Q. What is your recommendation for an appropriate default allocation factor to apply to new non-emitting resources?

A. The Commission should direct PacifiCorp to revise the proposed Protocol to default future non-emitting resources as follows:

- If procured to serve the load of a specific jurisdiction based on funding designation or regulatory direction, the generation plant should be assigned to that jurisdiction irrespective of whether it is located in the jurisdiction (or its location has not yet been determined).
- If procured for system benefit, then the generation plant should be assigned to SG-F.

In circumstances where the above defaults are not the best approach, PacifiCorp should announce its intentions or propose an alternative allocation factor in the earliest possible proceeding so that it may be reviewed and then used in forecasts and for other purposes with full regulatory support.

VI. HEDGING AND MARKET TRANSACTION COSTS

Q. Please summarize PacifiCorp's approach to hedging and market transaction costs.

A. PacifiCorp has made a number of proposals to change its hedging and market transaction practices for modeling net power costs. In some cases, these changes reflect actual changes in PacifiCorp's hedging and market transaction costs. In others, the changes are proposed as improvements to past NPC calculations.

In this section, I will discuss three of these changes that I believe merit the Commission's attention.

A. Separate Washington Hedging Book

Q. Please summarize PacifiCorp's proposal to create separate power and gas hedge books for Washington.

A. PacifiCorp explains this change as follows:

> The Company proposes to create two separate power and gas hedge books […] Additionally, the risk management policy will be updated to create risk limits to address the resource adequacy position and the average energy position of the two power hedge books. This will allow the Company to manage risk to net power costs (NPC) on behalf of Washington customers, while ensuring compliance with all relevant state laws.[62]

The net effect of this proposal is that PacifiCorp will continue to ensure resource and energy adequacy on a system-level basis, but will also independently determine the Washington position (forecast output of the Washington generation portfolio compared to the Washington load forecast).[63]

[62] Wilding, Exh. MGW-1T, at 11-12.
[63] *Id.* at 13.

Q. How do you characterize PacifiCorp's proposal to create a separate hedge book for Washington?

A. Overall, PacifiCorp's proposal to hedge for Washington appears to move substantially towards the position advocated by Staff in the 2023 PCAM (UE-230482) by Witness Yeomans as well as related recommendations by other parties.

However, the proposal remains unclear and needs further explanation. Witness Wilding states that, "PacifiCorp will continue to operate and balance as a system"[64] but also use "separate tracking … to ensure that the Company can maintain compliance with Washington state law …".[65] It is unclear whether there could be occasions in which PacifiCorp will make hedging transactions that are specifically intended to serve Washington customers and that would not have been transacted if PacifiCorp was only operating and balancing as a system.

Similarly, it is unclear how "a separate hedge book for Washington"[66] is compatible with no changes being proposed to the natural gas hedging limits. PacifiCorp states that, "The Washington gas position will be subject to the same hedge percentage requirements that are applied to the remainder of the system," but also states that, "Washington's gas requirement will be 'based on the forecasted requirements of the Chehalis plant, coupled with Washington's allocated share of the requirements for Jim Bridger units 1 and 2'."[67]

This seems to me to be a material change to PacifiCorp's hedge limits. First, the use of two separate hedge percentage requirements is likely to result in additional

[64] *Id.* at 14.
[65] *Id.* at 14.
[66] *Id.* at 15.
[67] Wilson, Exh. JDW-12.

hedges being executed due to triggering the new Washington requirement when the system requirement is already fulfilled. Second, the application of a blended standard for Jim Bridger units 1 and 2 (both the Washington and system requirements apply to different portions of the fuel supply) introduces further complications. Exactly how these will be implemented, and the implications of these changes for Washington NPCs, is a material point that needs clarification and review.

Q. Has PacifiCorp indicated that it will provide further regulatory filings to clarify its new hedging practices?

A. No. In response to WUTC DR-60, PacifiCorp did not commit to making a filing to provide further details on the implementation of this risk management practice. Instead, PacifiCorp states that

> The Company intends to review the revised risk management program with parties in Washington prior to seeking approval from the risk oversight committee and PacifiCorp's chief executive officer (CEO), with implementation contemplated on or about January 1, 2026.[68]

Q. How do you recommend that the Commission address the lack of clarity about this proposal to create a separate hedge book for Washington?

A. I recommend that the Commission require some type of compliance filing to provide further details on the implementation of this risk management practice, with an opportunity to ask questions. I do not object to an informal review process. However, the process proposed by PacifiCorp in response to WUTC DR-60 will not provide a

[68] Wilson, Exh. JDW-21, at (a).

suitable record for future review, so a filing in this or another suitable proceeding would be more appropriate.

B. Modeling Future Hedging Costs

Q. Please summarize PacifiCorp's proposed approach to modeling the impact of hedging on power costs.

A. PacifiCorp's proposal includes incremental 25 MW energy blocks that are added to its power cost forecast model, "[t]o reflect the fact that the Company will eventually need to hedge each quarter at a minimum average of 75 percent."[69]

PacifiCorp does not actually intend to purchase these energy blocks.

PacifiCorp justifies this model construct as follows:

> The Aurora model optimizes the system perfectly, executing sales and purchase transactions within fractions of a megawatt-hour (MWh), resulting in the lowest possible net power cost (NPC) forecast based on the provided inputs.
>
> … By inputting quarterly incremental 25 megawatt (MW) energy blocks directly into the Aurora model, in line with the Company's hedging program, the model's ability to unrealistically perfect the system is limited by the realistic presence of the incremental 25 MW energy blocks as hedges.[70]

[69] Mitchell, Exh. RJM-1CT, at 27.
[70] Wilson, Exh. JDW-6.

Q. Is PacifiCorp's proposed change to its model reasonable?

A. No. As PacifiCorp notes, its modeling approach "*is not comparable to determining the 'impact' of a hedging policy on actual operations*, where energy obligations, outage events, and renewable capabilities are not known perfectly in advance."[71]

I acknowledge that PacifiCorp has identified a reasonable issue in its power cost forecast. There is almost certainly a gap between the perfect forecast created by Aurora (without the 25 MW blocks) and a more realistic expectation for the impact of hedging transactions on power costs.

Nonetheless, PacifiCorp has not validated this model against historical transaction data or provided any other evidence supporting this cost. PacifiCorp states that its transaction history "indicates that forward hedges are executed at or about the prevailing market price at the time of execution, on average."[72]

The net benefit, or cost, of PacifiCorp's proposed modeling approach is the difference between (a) the current (as-filed) market price from PacifiCorp's Official Forward Price Curve (OFPC) for the forward hedge (25 MW block) at the forecast transaction date and (b) the Aurora-generated DA/RT price for the date that the forward hedge is either used or sold.

One problem here is that the OFPC price is not a forecast of the price that would be transacted at, but rather the as-filed OFPC market forward price. A simple way of thinking of this is that it is a hedge of a hedge. And that is not a cost PacifiCorp incurs or expects to incur in the future.

[71] Wilson, Exh. JDW-6 (emphasis added).
[72] Mitchell, Exh. RJM-1T, at 28.

The second problem is that the size of the forward hedge is an arbitrary 25 MW block. These are not transactions that PacifiCorp specifically anticipates completing, but rather a representation of possible transactions that may occur.

Essentially, this proposal is a tracking mechanism – an estimated cost for hedges that will be embedded into rates before the Company hedges for power and books the related costs.

Q. Does PacifiCorp's proposal align with its proposal to execute and allocate hedges to a Washington book?

A. No. In response to a data request, PacifiCorp states,

> As for whether the Company will execute hedges specifically for Washington customers that might not otherwise have been executed, that is a possible byproduct of the revised approach to risk management. However, an equally likely byproduct of this revised approach is that the Company may forgo hedges it otherwise would have executed and allocated to Washington, given that Washington is now being allocated a larger share of generating resources …[73]

It appears to me that the hedging cost forecast that PacifiCorp has prepared does not take into account the impact of the Washington Book on either Washington-specific hedge execution or forgone hedges not allocated to Washington.

Q. Does PacifiCorp's proposed hedging cost meet the Commission's established standard for known and measurable costs?

A. No. As the Commission has noted, "Washington uses a hybrid test year approach that allows pro forma adjustments only for known and measurable changes–not

[73] Wilson, Exh. JDW-11.

budgeted or projected changes–that occur, generally within a reasonable time after the end of the test year."[74] The Commission will allow ratemaking treatment for these known and measurable events where the utility can show that it has properly considered offsetting factors.[75]

The Commission has stated that an event is "known" where it "causes a change to test year levels . . . occur[s] either within or soon after[] the test year and [is] in place during the period rates will likely be in effect."[76] And the Commission has stated that an expense is an "actual expenditure, invoice, contract, or other specific obligation."[77]

For PacifiCorp's proposal, the *expense* is clearly not known, but PacifiCorp could plausibly argue that the *event* is known, as it is triggered by its Risk Management Policy (2021) that requires "positions be hedged at a level where, on average, a minimum of 75 percent of each month's peak hour is hedged in the first quarter of the future."[78]

The Commission has stated that a cost is not considered measurable when the utility bases it on "an estimate, a projection, the product of a budget forecast, or some similar exercise of judgment – even informed judgment – concerning future . . . expense."[79] The Commission has found it reasonable to relax these standards to some

[74] *Wash. Utils. Transp. Comm'n v. Pacific Power & Light Co.*, Dockets UE-140762, UE-140617, UE-131384 & UE-140094, Order 08, at 3 ¶ 8 (Mar. 25, 2015).
[75] WAC 480-07-510(3)(c)(ii).
[76] *Wash. Utils. Transp. Comm'n v. PacifiCorp d/b/a Pacific Power & Light Co.*, Docket UE-100749, Order 06, at 11-12 ¶ 14 (Mar. 25, 2011).
[77] *Wash. Utils. Transp. Comm'n v. Avista Corp.*, Dockets UE-090134, UG-090135 & UG-060518, Order 10, at 21 ¶ 45 (Dec. 22, 2009).
[78] Mitchell, Exh. RJM-1CT, at 27.
[79] *Wash. Utils. Transp. Comm'n v. Avista Corp.*, Dockets UE-090134, UG-090135 & UG-060518, Order 10, at 21 ¶ 45 (Dec. 22, 2009).

extent in the context of power costs,[80] but only to modeled power cost results, because the Commission has concluded that "the modeled results are generally acceptable if the model inputs are reasonable."[81]

For its hedging cost proposal, PacifiCorp has manually selected the amount of the power hedge transaction and manually priced them at its as-filed OFPC prices. PacifiCorp has intentionally substituted these choices for the Aurora model transaction volumes and prices. For these reasons, I believe that PacifiCorp's proposal fails the Commission's test for a known and measurable cost.

Q. What is your recommendation?

A. I recommend that the Commission reject the $22.8 million increase in NPCs associated with this modeling change.[82] Until PacifiCorp is able to develop a known and measurable cost for its hedging contracts, PacifiCorp should value those transactions at Aurora-generated market volumes and prices.

The use of Aurora-generated market volumes is reasonable, because these volumes are the result of the net transactions (hedges purchased minus hedges sold). The use of Aurora-generated market prices is the most reasonable option, as compared to the OFPC prices, because it is generated from the model inputs and reflects the model's best estimate of future prices at the time that PacifiCorp expects to require delivery of the specified power volume.

[80] *See* WAC 480-07-510(3)(c)(ii) ("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.").
[81] *Wash. Utils. Transp. Comm'n v. Avista Corp.*, Dockets UE-090134, UG-090135 & UG-060518, Order 10, at 22 ¶ 49 (Dec. 22, 2009).
[82] Mitchell, Exh. RJM-1T, at 29.

The hedging volumes (i.e., those volumes required to meet PacifiCorp's requirement to hedge each quarter at a minimum average of 75 percent) should be excluded from the market sales capacity limits, discussed in Section VI.C below, as proposed by PacifiCorp.

If, at some point in the future, PacifiCorp is able to provide a model-based solution for estimating the volumes and prices of hedges required to meet its risk policy, such a proposal could meet the Commission's standard.

C. Market Sales Capacity Limits

Q. How has PacifiCorp changed its approach to market sales capacity limits in this PCORC?

A. PacifiCorp has changed its market sales capacity limits to only restrict spot market sales volumes, increasing NPC by $3.7 million.[83] It has conducted a benchmarking study that it claims shows Aurora generates a greater volume of market transactions than the market has demonstrated are feasible.[84]

Q. What is your recommendation with respect to this change?

A. At this point, I neither endorse nor oppose this change. I am persuaded by the evidence that a restriction to spot market transaction volumes in Aurora is a reasonable improvement to PacifiCorp's modeling.

[83] Mitchell, Exh. RJM-1CT, at 29, 31.
[84] Mitchell, Exh. RJM-1CT, at 33.

However, I have two concerns with PacifiCorp's specific proposal. First, if the Commission accepts my recommendation, it may be necessary to revise the market sales capacity limit to account for the difference between the 25 MW block method of forecasting hedging requirements, which would tend to overstate the hedging requirements, as compared to hedging to the 75 percent minimum standard. This may be a relatively small adjustment and, if so, may be disregarded in the interests of regulatory efficiency.

Second, while it is reasonable to utilize a four-years average volume for spot market transactions, PacifiCorp has not specifically justified its choice. As noted by PacifiCorp, there is a significant trend in recent market transaction volumes. This gives me some pause as to whether there might be another method to determine a reasonable limit to smart market transaction volumes.

If the Commission approves this proposal, I recommend that it direct PacifiCorp to re-analyze this method in its next GRC or PCORC application to verify its reasonableness.

VII. WEIM BENEFITS METHOD

Q. Please summarize PacifiCorp's method for forecasting benefits from the Western Energy Imbalance Market (WEIM).

A. PacifiCorp has updated its WEIM benefits method "using WEIM transfers as a predictor variable," using two years of historical data to forecast WEIM transfer assumptions in the model.[85]

Q. Is PacifiCorp likely to revise its WEIM benefits method in future proceedings?

A. Yes, "PacifiCorp is planning to re-evaluate the WEIM benefit forecasting models in relation to future work to create Extended Day Ahead Market (EDAM) benefit forecasting models."[86] Since the EDAM is scheduled for implementation in 2026, with partial participation (compared to the WEIM), PacifiCorp has not yet modeled the EDAM within its production cost model.[87]

Q. Is PacifiCorp's WEIM benefits method reasonable?

A. Yes. Forecasting WEIM benefits is challenging because the WEIM market, the resource mix, and load requirements are changing rapidly, both now and with implementation of the EDAM beginning in 2026. It is understandable that any test year might be out of date almost before actual data are available.

Considering this complexity, PacifiCorp states that it "does not use predictions of future benefits" in its WEIM model.[88] Even though PacifiCorp is aware that, "there has been a big decrease in PACE Export benefits compared to the

[85] Mitchell, Exh. RJM-9, at 8.
[86] Mitchell, Exh. RJM-9, at 9.
[87] Mitchell, Exh. RJM-9, at 23-25.
[88] Wilson, Exh. JDW-8, at (a).

last few years,"[89] it is not able to predict whether that decreasing trend will continue or, perhaps, reverse.

Overall, PacifiCorp's testimony on this topic suggests that it has explored a reasonable set of alternative model methods and selected the one that performs the best. It may or may not be the best available method, but PacifiCorp's efforts on this model component are reasonable.

However, in one respect, I believe PacifiCorp's model could be easily improved.

Q. How could PacifiCorp's model be improved?

A. PacifiCorp forecasts WEIM transfers on a seasonal basis. This is in contrast to most of its NPC model, which is generally forecast on a monthly basis. PacifiCorp assumed the following seasons in its model:

- Winter: December – February
- Spring: March – May
- Summer: June – August
- Fall: September – November[90]

In response to a data request, PacifiCorp stated that it "has not performed any detailed analysis on the seasonal attributes of the WEIM [or performed any analysis on alterative definitions of seasons], therefore the definitions used in the WEIM forecasting models are approximations."[91]

[89] Mitchell, Exh. RJM-9, at 7.
[90] Mitchell, Exh. RJM-9, at 6.
[91] Wilson, Exh. JDW-7.

Elsewhere in the same model, PacifiCorp models PACE Imports and Exports models using a "Solar_Increasing" variable that estimates the amount of solar capacity that may be available for transfer in the WEIM during the March through July months.[92] The term "increasing" relates to planned growth in solar deployment in California, which produces excess solar energy that flows from the southwest region to the rest of the WEIM footprint during the spring and early summer months. This analysis appears sound and important to the overall model.

However, because PacifiCorp's WEIM transfer model is built around seasonal (not monthly) averages, its definition of the summer season is problematic. While each month in the spring season includes "Solar_Increasing" capacity, only two of the three summer months include "Solar_Increasing" capacity. Because the three months are averaged together, August includes "Solar_Increasing" capacity that should not be available, and the months of June and July include too little "Solar_Increasing" capacity.

Revising the model to align the seasons and the "Solar_Increasing" variable could result in some improvement in the model's performance. Another option would be to create a monthly (not seasonal) model, but given that it is a two-year model, a monthly model would be more strongly influenced by weather events than a seasonal model.

[92] Mitchell, Exh. RJM-9, at 5; Wilson, Exh. JDW-25C.

Q. What do you recommend?

A. I recommend that PacifiCorp consider updating its WEIM transfer model with alternative seasonal definitions to align its output with its understanding of the California solar surplus delivery months. There are several specific options that PacifiCorp could explore, and it could use some 2025 data in that analysis since the March – July period is now almost complete.

If PacifiCorp is not able to provide an updated model in this proceeding, I recommend that the Commission direct PacifiCorp to align any seasonal definitions in its WEIM or EDAM benefits model with its understanding of solar export trends in future NPC model filings.

VIII. PROPOSED TRACKERS

Q. Please summarize PacifiCorp's proposed trackers.

A. PacifiCorp is proposing a $1.4 million credit to the PTC tracker and a $2.2 million credit for the non-NPC coal cost tracker. The PTC tracker is routinely considered in power cost rate cases and I have not identified any concerns with PacifiCorp's proposal.

Q. Is the non-NPC coal cost tracker appropriate for recovery?

A. Yes. As discussed above, in Order 09/07 in PacifiCorp's 2023 General Rate Case, the Commission ordered that,

> PacifiCorp should be required to file a PCORC by April 1, 2025, with a rate effective date of January 1, 2026, to remove coal-fired

> resources from rates. As AWEC witness Mullins explains, removing coalfired resources from rates is likely to have a significant effect on NPC, and it would be appropriate to consider other revenue-requirement elements that may offset increases to NPC. A simple NPC update, however, would not provide a sufficient opportunity for the parties or the Commission to consider these issues.[93]

The Commission clearly states that in this PCORC, PacifiCorp is to "remove coal-fired resources from rates." An adjustment to the coal cost tracker is directly responsive to the Commission's order and should be implemented.

I have not identified any concerns with the amount of the credit.

IX. MARKET POSITION ANALYSIS

Q. Why did PacifiCorp include a market position analysis in its PCORC filing?

A. In its order in the 2022 PCAM proceeding, the Commission directed the following:

> We recognize that there are benefits and cost efficiencies to planning for and operating the system as a whole, or at least that has been the case in the past. But our job is not to regulate the rates of the system, but for PacifiCorp's customers in Washington. Accordingly, PacifiCorp needs to continue to show it is improving the short position of Washington on a least-cost basis, in accordance with Washington law, which includes CETA. In the future, PacifiCorp must show analysis of the alternative, showing what rates for Washington customers would have been in the preceding 10 years if PacifiCorp had closed Washington's position with generation resources on its system rather than market positions, and a cost benefit analysis showing what rates will be 10 years into the future using Washington-based generation resources versus market position. We expect that given market conditions today, the benefits of using market positions is diminishing.
>
> We find credence in the points raised by Public Counsel regarding the benefits Washington-based resources would provide to

[93] *Wash. Utils. Transp. Comm'n v. PacifiCorp d/b/a Pacific Power & Light Company*, Dockets UE-230172 & UE-210852 (Consolidated), Order 09/07 at 5 ¶ 14 (May 16, 2024).

> Washington ratepayers. Going forward, if it becomes clear that the usage of market positions no longer provides economic benefit to Washington ratepayers, then the Commission shall disallow recovery of certain costs of the PCAM in order to protect ratepayers.[94]

Q. Please summarize the results of PacifiCorp's analysis.

A. PacifiCorp's Counterfactual analysis compares its current system with an alternative system that includes 75 MW wind and 25 MW solar online in 2019, and 45 MW wind and 25 MW solar in 2024. The analysis finds that Washington customers would have faced higher costs prior to 2021 and slightly lower costs from 2021-2024, with an overall increase in NPCs for 2026-2035. The Counterfactual relies on WIJAM resource allocations.

Q. What is your opinion of this analysis?

A. I did not identify any technical flaws in this analysis. However, my opinion is that the future analysis – considering the 2026-2035 period – is conceptually flawed.

My concern with PacifiCorp's future analysis is that the "net position balancing" analysis is flawed. I explained my concerns about PacifiCorp's net position balancing analysis in my 2022 PCAM testimony, and the Commission did not find it compelling.[95] Notwithstanding the specifics of that proceeding, in this proceeding PacifiCorp's Washington 2026 Protocol and associated hedging practices

[94] *Matter of PacifiCorp d/b/a Pacific Power & Light Company, 2022 Power Cost Adjustment Mechanism Annual Report*, Docket UE-230482, Order 07, at 36-37 ¶ 137-138 (October 30, 2024).
[95] *Id.* at 29 ¶ 109-110.

appear to substantially address some of my concerns and, overall, provide an improved baseline against which such a counterfactual could be compared.

I concede that PacifiCorp's future analysis is reasonable, in that compliance with the Commission's order using the Commission-approved methods from 2023 is probably more appropriate than using an unapproved method being proposed for the first time in this proceeding.

In summary, I do not believe that PacifiCorp's analysis "proves" that its market positions provided a clear economic benefit to Washington customers. But neither does it provide a basis for a disallowance, both because of the questionable baseline and the variation in the outcomes over different time periods.

In my opinion, maintaining the requirement for this counterfactual analysis will be a useful exercise and check on PacifiCorp's IRP process, to verify that PacifiCorp's resource planning and procurement have outcomes that are consistent with Washington customers' interests.

In its next analysis, PacifiCorp will doubtless rely on the Washington 2026 Protocol, or some variant thereof. This baseline will provide a much more informative "counterfactual" analysis. Nonetheless, unless the results show a strong and compelling trend of increased customer costs, it could be difficult to justify a disallowance based on such an analysis due to the inherent uncertainties in modeling and forecasting.

Q. Does this conclude your testimony?

A. Yes.