BEFORE THE WASHINGTON

UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PACIFICORP d/b/a PACIFIC POWER AND LIGHT CO., Respondent.	DOCKET UE-250224

CONFIDENTIAL RESPONSE TESTIMONY OF BRADLEY G. MULLINS

ON BEHALF OF

ALLIANCE OF WESTERN ENERGY CONSUMERS

(REDACTED VERSION)

August 20, 2025

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I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Bradley G. Mullins, and my business address is Vihikari 10 Suite 4023, Kempele Finland FI-90440.

Q. PLEASE STATE YOUR OCCUPATION AND ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am the Principal Consultant for MW Analytics, a consulting firm that provides professional services to large energy consumers, primarily in the Western United States. I am appearing in this matter on behalf of Alliance of Western Energy Consumers ("AWEC"). AWEC is a non-profit trade association whose members are energy consumers located throughout the Pacific Northwest, including electric service customers of PacifiCorp.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND WORK EXPERIENCE.

A. I have a Master of Accounting degree from the University of Utah. I have sponsored testimony in several regulatory jurisdictions in the United States, including before the Washington Utilities and Transportation Commission (the "Commission"). A list of recent cases where I have submitted testimony can be found in Mullins, Exh. BGM-2.

Q. WHAT IS THE PURPOSE OF YOUR CROSS-ANSWERING TESTIMONY?

A. I discuss PacifiCorp's Power Cost Only Rate Case ("PCORC") filing, including its request to implement a modified interjurisdictional cost allocation method, which it refers to as the Washington 2026 Protocol. Specifically, I first discuss PacifiCorp's proposal to establish Net Power Costs ("NPC") of $194.6 million, an approximate 8 percent increase

relative to the $184.0 million amount established for the second year of PacifiCorp's current multi-year rate plan,[1] and discuss issues identified with respect to PacifiCorp's forecast. I also evaluate its 2026 Protocol inter-jurisdictional allocation method, including its proposals to allocate 100% of the Chehalis gas fired power plant ("Chehalis") to Washington ratepayers and to modify certain inter-jurisdictional allocation factors.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS IN THIS PROCEEDING.

A. My recommendations, for both NPC and interjurisdictional allocation, are detailed in **Table 1**, below, followed by brief descriptions.

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[1] Exh. RJM-1CT at 3:2-19.

Table 1
Summary of Recommendations
Washington-Allocated Revenue Requirement Deficiency/(Sufficiency) – Whole Dollars

	Adjustment	NPC	PTCs	Fixed / Other	Total Rev. Req. Def. / (Suf.)
1	**Filed Increase**	**16,291,491**	**(1,392,909)**	**19,012,491**	**33,911,073**
	Adjustments:				
2	Aurora v.16	1,333,055	-	-	1,333,055
3	Wind Production Penalty	(12,183,067)	(7,382,988)	-	(19,566,055)
4	BPA Real Power Losses	(1,643,175)	-	-	(1,643,175)
5	BP-26 Rate Case	1,649,018	-	-	1,649,018
6	Nodal Pricing Model	(727,217)	-	-	(727,217)
7	CETA Adder	(15,378,813)	-	-	(15,378,813)
8	Hypothetical Hedges	(16,695,810)	-	-	(16,695,810)
9	Non-Precedential Changes	(10,216,942)	-	-	(10,216,942)
10	Jim Bridger 1&2 Gas Alloc.	2,622,247	-	(6,481,380)	(3,859,134)
11	SO Allocation Factor	-	-	(2,211,934)	(2,211,934)
12	Industrial Curtail. Contracts	(2,271,196)	-	-	(2,271,196)
13	PTC Rate	-	(1,126,917)	-	(1,126,917)
14	**Subtotal**	**(54,844,956)**	**(8,509,905)**	**(8,693,315)**	**(72,048,175)**
15	**Adjusted**	**(38,553,465)**	**(9,902,814)**	**(38,553,465)**	**(48,456,279)**

Net Power Cost Forecasting Recommendations

1. ***Wind Production Penalty.*** *PacifiCorp has implemented a method in the Aurora model to simulate the curtailments of wind resources. In the model, these curtailments have major impacts on Washington-allocated NPC and rates, resulting in significantly increased cost from lost zero-cost energy and foregone production tax credits ("PTCs"). These curtailments, however, are inconsistent with how PacifiCorp manages wind resources in actual operations; are inconsistent with the assumptions used when these resources were procured; and in the model, are being driven predominantly by economic constraints placed on coal-fired resources allocated to other states. PacifiCorp's modeling of wind resources is neither accurate nor fair to Washington customers, and accordingly, I recommend that its wind curtailment modeling method not be used to forecast NPC in this proceeding.*

2. ***Bonneville Power Administration Real Power Losses*** *— In early 2024, PacifiCorp transitioned from physical to financial real power loss settlement with the Bonneville Power Administration ("BPA"). Historically, BPA power losses have been included in the loss factors used for its load forecast. PacifiCorp's filing includes a new wheeling charge for BPA financial losses, although it continues to include physical power losses in its load forecast. To avoid double counting the impact of BPA power losses, I recommend the financial loss settlements be eliminated from its forecast.*

3. ***BPA BP-26 Rate Case*** *— PacifiCorp's filing neglected to consider the impacts of the BP-26 rate case on its transmission rates, which will result in a significant increase to its wheeling costs. I have considered that increase in my forecast.*

4. ***Nodal Pricing Model Fee*** *— PacifiCorp includes a wheeling charge for the California Independent System Operator ("CAISO") Nodal Pricing Model ("NPM"), which it never developed in accordance with the 2020 Protocol and will no longer procure following the implementation of the Extended Day Ahead Market ("EDAM"). I recommend that the NPM fees be removed from the NPC forecast as not used and useful to Washington customers.*

5. ***CETA Compliance Costs*** *— PacifiCorp models a 50% adder on the cost of structured products modeled in Washington allocated NPC. As a result of the passage of House Bill 1326, PacifiCorp is now allowed to purchase unspecified, structured products to serve Washington customers, and that adder is no longer applicable.*

6. ***Hypothetical Hedging Costs*** *— PacifiCorp has implemented a new method for incorporating hypothetical, structured hedging products into the Aurora model, which results in substantial costs being allocated to Washington ratepayers. The cost PacifiCorp models for these products is not a true hedging cost, but a system balancing cost associated with purchasing fixed blocks of power. Those impacts, however, are already reflected in the DA/RT adjustment method used to simulate the cost of purchasing 25 MW monthly blocks of power.*

7. ***Non-Precedential Modeling Changes*** *— I recommend that modeling changes that PacifiCorp refers to as "Non-Precedential Modeling Improvements" not be adopted in this case. PacifiCorp did not file any testimony on these changes other than referencing its Rebuttal Testimony from the 2023 GRC, which does not satisfy its burden of proof with respect to those issues.*

Interjurisdictional Cost Allocation Recommendations

8. ***Interjurisdictional Allocation Review*** — *While I recommend the Commission evaluate PacifiCorp's proposed changes to interjurisdictional allocation in this docket, I also recommend that the Commission postpone full and final approval of the new allocation framework to PacifiCorp's next general rate case, where the full effects of changes to interjurisdictional allocation can be evaluated.*

9. ***Generation Fixed Allocation Factors*** — *I recommend the Commission approve the transition to fixed allocation factors for generation resources, so long as all of the costs and benefits of those resources can be adequately assigned to Washington.*

10. ***Chehalis Allocation*** — *I recommend the Commission accept PacifiCorp's proposal to reallocate Chehalis to Washington ratepayers.*

11. ***Jim Bridger Gas Units 1 & 2*** — *In conjunction with the reallocation of Chehalis, I recommend that Washington's share of the Jim Bridger Gas Units 1 and 2 (Bridger 1&2) also be reallocated to other states. The Jim Bridger Gas Units are highly emitting resources, with emissions comparable, if not worse than those of coal plants. Their allocation to Washington also increases its allocated cost.*

12. ***Rolling Hills Allocation*** — *Because the incremental share of Rolling Hills results in net cost to Washington customers, I recommend that Washington not assume the portion of the plant disallowed in Oregon. However, if the Commission accepts my adjustment to PacifiCorp's wind production penalty, I recommend accepting PacifiCorp's reassignment of Rolling Hills.*

13. ***System Overhead Allocation Factor*** — *I recommend that PacifiCorp's proposed change to the System Overhead ("SO") factor not be considered in this docket, as it falls outside of the scope of a PCORC. Further, if it is considered, I recommend PacifiCorp's proposed change be rejected because it would change the allocation of system overhead costs to be predominantly energy- and capacity-related, which is contrary to principles of cost causation.*

14. ***Industrial Curtailment Contracts*** — *Given the move to fixed factors, I recommend that industrial curtailment contracts of other states not be considered in Washington NPC.*

15. ***Hedging Allocation*** *— I recommend the Commission decline to pre-approve PacifiCorp's hedging policy or the structured contracts that will be allocated to Washington customer rates.*

16. ***Decommissioning Costs*** *— I recommend that the Commission wait until PacifiCorp's next general rate case to make a determination on decommissioning costs in order to consider the extent to which Washington's share in coal resources is assumed by other states, in which case the Washington decommissioning liability should be reduced. I also recommend PacifiCorp be required to submit an annual compliance filing detailing the total amount of decommissioning and remediation costs collected from Washington ratepayers.*

Other Recommendations

17. ***Production Tax Credit Rate*** *— I demonstrate that the economic indicators underlying the PTC rate for 2026 have exceeded the threshold necessary to trigger the PTC rate to increase to 3.1 ¢/kWh, which I recommend be used as the basis for the PTC forecast in this case.*

II. BACKGROUND

Q. PLEASE SUMMARIZE THE CIRCUMSTANCES FOR PACIFICORP MAKING ITS FILING IN THIS PROCEEDING?

A. This proceeding is, in part, the outcome of PacifiCorp's 2023 GRC.[2] In that proceeding, AWEC recommended PacifiCorp be required to file a PCORC by April 1, 2024, in order to address the NPC and other offsetting impacts of removing coal from rates pursuant to the Clean Energy Transformation Act ("CETA").[3] In its Order 09/07 in the 2023 General Rate Case ("2023 GRC"), the Commission agreed with AWEC's recommendation based upon the following finding:

[2] *In re PacifiCorp's General Rate Case,* Docket No. UE-230172 & UE-210852 (consolidated) (March 17, 2023).

[3] *Id.,* Mullins, Exh. BGM-1T at 22:7-23:9 (Sep. 14, 2023).

> The Commission agrees with AWEC 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.[4]

Thus, the intended scope of this filing was to consider the NPC impact of removing coal from rates along with other offsets, such as increased accumulated depreciation from new wind resources.[5]

Q. PLEASE PROVIDE SOME BACKGROUND ON THE 2020 PROTOCOL AND PACIFICORP'S MULTI-STATE PROCESS.

A. The 2020 Protocol was an agreement between interested parties in PacifiCorp's six state service area through a negotiating body and framework, generally known as the Multi-State Process ("MSP"). Since at least the early 2000s, the MSP has been the principal venue for addressing and resolving issues and disputes surrounding interjurisdictional cost allocation methods between participating jurisdictions. Through the MSP, participating parties have reached successive agreements to establish common allocation methods and frameworks, including the Revised Protocol,[6] the 2010 Protocol,[7] the 2017 Protocol,[8] and finally, the 2020 Protocol. The methods in these allocation agreements have generally evolved based on a rolled-in method of cost attribution, one in which each

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4 2023 GRC, Order 09/07, Granting Motion for Clarification; Granting Motion for Leave to Reply; Granting Leave to Respond at ¶ 14 (Internal citations omitted).

5 2023 GRC, Mullins, Exh. BGM-1T 22:7-21.

6 *In re PacifiCorp, Request to Initiate an Investigation of MultiJurisdictional Issues and Approve an InterJurisdictional Cost Allocation Protocol,* Or.PUC Docket No. UM 1050, Order 05-021, Stipulation Adopted; Revised Protocol Ratified (Jan. 12, 2005).

7 *Id.,* Order 11-244, Stipulation Adopted (Jul. 05, 2011).

8 *Id.,* Order 16-319, 2017 Protocol Adopted (Aug. 23, 2016).

jurisdiction receives a percentage of total-system costs using variously defined allocation factors.

Q. HAS WASHINGTON HISTORICALLY PARTICIPATED IN THE MSP?

A. No. Prior to the negotiations leading up to the 2020 Protocol, Washington did not participate in the MSP. In Docket No. UE-061546 and UE-060817 (consolidated), instead of approving the Revised Protocol, the Washington Commission, citing the lack of benefits between PacifiCorp's two balancing authority areas ("BAA") (formerly called control areas), relied on an independent interjurisdictional cost allocation method, known as the Western Control Area ("WCA") method, which established rates that included only the resources located in PacifiCorp's Western BAA or that could by physically delivered into the Western BAA. In the negotiation process leading up to the 2020 Protocol, however, Washington began participating in the MSP.

Q. WAS WASHINGTON A PARTY TO THE 2020 PROTOCOL?

A. Washington's participation in the 2020 Protocol was based on Appendix F of the 2020 Protocol. Under that Appendix, Washington was to continue using an allocation framework different from the methods outlined in the 2020 Protocol for PacifiCorp's other five jurisdictions. The Washington method was referred to as the "Washington Interjurisdictional Allocation Methodology," or WIJAM. Under WIJAM, Washington agreed to modify the WCA method to include a rolled-in share of non-emitting resources in PacifiCorp's Eastern BAA. Pertinent to this PCORC, the WIJAM did not expressly define the method to be used to allocate NPC to Washington, although there was recognition that Washington would realize all of the benefits of resources allocated to

Washington rates.[9] In PacifiCorp's 2020 General Rate Case, however, PacifiCorp presented a spreadsheet calculation, using a monthly energy balancing approach, which has since been used to allocate NPC to Washington, and PacifiCorp is not proposing to substantively modify that approach in the context of the Washington allocation framework it proposes in this docket.

Q. WHAT WAS DIFFERENT ABOUT THE 2020 PROTOCOL COMPARED TO PRIOR MSP AGREEMENTS?

A. While all agreements prior to the 2020 Protocol envisioned a shared, rolled-in system (with the notable exception of Washington), in the 2020 Protocol parties contemplated the possibility of an eventual transition away from a dynamic, rolled-in allocation method, to a permanent allocation framework in which states each received fixed slices of resources included in PacifiCorp's portfolio.[10] This was done in part due to a divergence between state policies, including Washington and Oregon, that were pursuing aggressive renewable and emission policy objectives and those that were not, including Utah, Idaho and Wyoming. Accordingly, the 2020 Protocol was developed as a transitory agreement, which was to be a bridge for the development of a long-term, permanent agreement between the states.

To accomplish this, the 2020 Protocol was divided into two general timeframes: an Interim Period and a Post-Interim Period. Principally, parties agreed that during the Interim Period, the allocation method established in the 2017 Protocol, subject to several modifications, would continue to be used, and over the duration of the Interim Period,

[9] See 2020 Protocol, Appendix F § 6.
[10] 2020 Protocol § 6.1.

parties would continue negotiations of a permanent allocation framework for the Post-Interim Period. Issues that remained unresolved in the 2020 Protocol – known as "Framework Issues" – included items, such as the allocation of NPC using a Nodal Pricing Model, as well as realignment of state generation portfolios, with Washington's Clean Energy Transformation Act, specifically called out.[11]

Q. HOW LONG WAS THE INTERIM PERIOD SUPPOSED TO LAST?

A. The Interim Period was intended to last until December 31, 2023. Notwithstanding, Parties were continuing to negotiate the elements of the Post-Interim Period method, and the MSP parties agreed to extend the Interim Period until December 31, 2025.

Q. WHY DID PARTIES NOT REACH AN AGREEMENT REGARDING THE POST-INTERIM PERIOD ALLOCATION METHOD?

A. The MSP parties, including Washington, engaged in extensive discussions following the execution of the 2020 Protocol to develop the Post-Interim Period allocation method. These discussions were progressing steadily until June 2024, when PacifiCorp unilaterally terminated all MSP negotiations. PacifiCorp informed parties that it would no longer be seeking a negotiated allocation method through the MSP between the states and that it would be developing its own proposals and presenting those to the states for approval.

Q. IS THE ALLOCATION METHOD PACIFICORP PRESENTED IN THIS CASE A PROTOCOL?

A. No. In the context of a negotiated agreement, a "protocol" typically refers to an agreement between parties about how terms are to be implemented. Since there was no

[11] *Id.* at § 6.4.

agreement reached between the states regarding the Post-Interim Period allocation method, referring to the new allocation method as the "2026 Protocol" is misleading. For purposes of this testimony, I refer to PacifiCorp's newly proposed allocation method as an allocation framework rather than a protocol. This is important because in **Link, Exh. RTL-2**, PacifiCorp presents a Washington 2026 Protocol document with a number of terms. Unlike the WIJAM, the terms of that document were not negotiated and agreed-to between parties. Accordingly, that document cannot be viewed as being "binding," in the same sense as Appendix F to the 2020 Protocol, on parties or the Commission in any future proceedings.

Q. HAS PACIFICORP PRESENTED A NEW ALLOCATION FRAMEWORK IN ITS OTHER STATES?

A. Yes. In early August, PacifiCorp made filings in several other jurisdictions proposing modifications to the 2020 Protocol. A copy of what PacifiCorp is calling the "2026 Protocol", as filed in Oregon, is attached as **Mullins, Exh. BGM-7**. While this was the first docket in which PacifiCorp presented a "2026 Protocol," it is apparent that the methods PacifiCorp is proposing in Washington are markedly different from the methods it is proposing in other states. While I discuss the details of PacifiCorp's Washington 2026 allocation proposal in **Section IV**, it is important to note here that there has been no agreement between the states regarding the methods under consideration in this case and that they are different than what PacifiCorp is proposing in other States. From this perspective, it is important for the Commission to acknowledge that it is not approving a negotiated agreement among the states. Nor is it approving a common method to be used throughout PacifiCorp's six-state service area. When it performs its evaluation of

PacifiCorp's proposals, the Commission should do so based on the methods that it finds produce rates that are "just, fair, reasonable and sufficient"[12] for Washington customers, which need not necessarily be the same nor complimentary to the method used in other states.

Q. IS IT APPROPRIATE FOR PACIFICORP TO SEEK APPROVAL OF A NEW ALLOCATION FRAMEWORK IN THIS DOCKET?

A. Because the allocation framework PacifiCorp is proposing to begin on January 1, 2026, has a significant impact on power costs, AWEC believes it is appropriate to *consider* these allocation proposals in this docket solely as they relate to PacifiCorp's NPC forecast. Notwithstanding, PacifiCorp's proposed Washington allocation method may have impacts on other costs borne by Washington customers that are not at issue in this proceeding. Therefore, as an overarching recommendation, AWEC recommends that the Commission's decisions with respect to interjurisdictional cost allocation in this case be non-precedential and subject to reevaluation in PacifiCorp's next general rate case.

Q. WHY IS IT APPROPRIATE TO FURTHER CONSIDER THE ALLOCATION FRAMEWORK IN A FUTURE GRC?

A. Since the scope of this case is limited, focusing solely on Power Costs, it is not possible to assess the full scope and impact of PacifiCorp's allocation methods on Washington rates. As I discuss below, there are certain aspects of PacifiCorp's proposal, such as the System Overhead allocation factor and decommissioning costs, which I recommend be deferred until a more holistic review can take place in a general rate case filing. Further, it is possible that other states may take different approaches, or that new developments,

[12] RCW 80.28.010(1).

such as PacifiCorp's participation in the EDAM, may have material impacts on the operation of PacifiCorp's system and cost causation generally, which may warrant further consideration in future cases. Finally, since the Commission is not approving a negotiated agreement, approval of an allocation method in this case is not necessarily binding in future cases, as it would be for a term-limited stipulation between parties, such as was agreed in the WIJAM. The allocation framework is not a "protocol" between the parties, but merely PacifiCorp's ratemaking proposal in this case, the reasonableness of which duly warrants further evaluation in future cases. As a general regulatory principle, a regulatory Commission typically cannot issue an order binding the decisions of future Commissions and future cases, and AWEC believes it would be unnecessary to do so in this case.

Q. CAN YOU PROVIDE A SPECIFIC EXAMPLE OF A TOPIC IN THE WASHINGTON 2026 ALLOCATION METHOD THAT SHOULD BE DEFERRED FOR LATER CONSIDERATION?

A. Yes. As discussed more fully later in this testimony, decommissioning cost are outside of the scope of NPC and the Commission should not approve an allocation of these costs without having the benefit of a full record on this issue. Similarly, PacifiCorp is not proposing any changes to the allocation of transmission costs in this case. Yet, given Washington's fixed resource portfolio, which excludes most large emitting resources, Washington will be using less generation resources than other states, warranting Washington assuming a lesser share of system transmission costs. There may be other issues that arise as well, and AWEC believes it would be most appropriate to consider those in the context of overall revenue requirement, rather than in a limited issue filing.

Q. WHAT PRINCIPLES SHOULD THE COMMISSION USE TO EVALUATE INTERJURISDICTIONAL COST ALLOCATION GENERALLY?

A. In general, the role of the Commission is to establish rates for PacifiCorp that are "just, fair, reasonable and sufficient,"[13] and the interjurisdictional allocation of costs are one of many considerations made when performing that evaluation. Accordingly, the reasonableness of the interjurisdictional cost allocation framework should be evaluated based on how it affects the rates of Washington ratepayers, not necessarily based on the methods used by other states. This case presents several unique circumstances, including the reallocation of resources that, under the WIJAM, were formerly attributed to other states, as well as the removal of certain resources from Washington rates. It is possible that the other states will not accept these modifications, although the principal consideration from Washington's perspective should be whether it is reasonable for Washington ratepayers, without regard to the decisions made by the other states.

Q. SHOULD PACIFICORP BEAR THE RISK TO THE EXTENT THERE ARE INCONSISTENCIES AMONG THE STATES?

A. Yes. PacifiCorp terminated negotiations of the Framework Issues group, and rather than seeking a common negotiated solution between the states, has elected to present its own recommended solution for individual approval at each state regulatory commission. PacifiCorp created and accepted the risk of divergent allocation decisions when it made the decision to abandon a negotiated solution in favor of a unilateral proposal presented to each of the states individually, and to the extent that states approve conflicting allocation methods that result in under-recovery, this is a risk that must fall on

[13] RCW 80.28.020.

PacifiCorp, not Washington ratepayers.[14] I would note that it is also possible for states to approve allocations of costs that result in over-recovery for PacifiCorp.

III. NET POWER COSTS

Q. HOW DOES PACIFICORP FORECAST NPC INCLUDED IN BASE RATES?

A. PacifiCorp's general rate case filings have historically established base rates using a forecast of NPC for a test period using an hourly production cost model. A production cost model is a numerical representation of PacifiCorp's system designed to simulate system dispatch using assumed forecast parameters, such as loads, resource attributes, market prices, and transmission constraints. It is important, however, not to confuse the simulation with the actual operation of PacifiCorp's system, as the purpose of the simulation is to develop an estimate of PacifiCorp's cost, as opposed to perfectly simulating how resources may, or may not, be dispatched in actual operations.

Prior to the 2021 PCORC filing, PacifiCorp had for many years used an in-house model known as the Generation Regulation and Incentives Decision ("GRID") tool to do this. In the 2021 PCORC, however, PacifiCorp proposed using Aurora, which was developed by and is licensed from third-party software developer Energy Exemplar. While the Aurora model uses different modeling algorithms and approaches, PacifiCorp attempted to generally align the methods used in Aurora with those formerly used in the GRID model. PacifiCorp has subsequently used it in the context of the 2023 GRC in

[14] *See* WUTC v. PacifiCorp, Docket No. UE-130043, Order No. 05 at 66 (December 4, 2013).

setting base NPC, along with the NPC update filed in the spring of 2025 to implement rate year 2 rates of the multi-year rate plan.

Q. IS WASHINGTON NPC CALCULATED DIFFERENTLY FROM OTHER STATES?

A. Yes. Historically, Washington has calculated NPC using a method known as the WCA method. This method calculated the stand-alone dispatch of resources located in PacifiCorp's Western BAA, with the ability to make sales and purchases from the Eastern Balancing Authority areas through a modeled hypothetical contract known as the Eastern Control Area Sale. That method changed, however, following the 2020 Protocol and the adoption of the WIJAM, which expanded the resources included in Washington rates to include non-emitting resources located in the Eastern BAA. Under WIJAM, NPC is calculated using a spreadsheet method that relies on a total-company estimate of NPC, rather than the stand-alone dispatch calculation used in the WCA method.

Under the method, Washington is allocated its share of the costs of generation from resources included in Washington rates. PacifiCorp then performs a monthly calculation that determines Washington's energy long or short position. That is, PacifiCorp determines if the resources allocated to Washington produced more (i.e. long) or less (i.e short) energy than Washington's load for the entire month. PacifiCorp subsequently assigns a market value to the monthly energy position using the system average cost of purchases and sales, with a specified ordering between the two depending on the long or short position.

Q. HAS PACIFICORP CHANGED THE METHOD IT USES TO DERIVE WASHINGTON ALLOCATED NPC?

A. No. PacifiCorp has not proposed any material changes to the monthly spreadsheet method established in the WIJAM for allocating NPC. Notwithstanding, in the 2020 Protocol, one of the Framework Issues for the Post-Interim period allocation method was the notion that there needed to be a method to track the costs and benefits of individual resources assigned to certain states. The method contemplated in the 2020 Protocol was a Nodal Pricing Model ("NPM"), which assigns a locational market price to both the loads and resources used to serve the customers of a particular state. PacifiCorp did not propose such a method in this case, and rather, proposes continuing the status quo.

Q. HAVE YOU IDENTIFIED ANY ISSUES WITH PACIFICORP'S WASHINGTON-ALLOCATED NPC?

A. Yes. I discuss several issues identified in my review below. As an initial matter however, some of these changes impact the calculation of total-Company NPC, whereas others have greater impact on Washington-allocated NPC. As a general principle, because the spreadsheet method is designed to forecast the NPC costs and benefits applicable to Washington-allocated resources only, the accuracy of total-company NPC is not necessarily at issue. The issue is whether the costs and benefits of Washington-allocated resources are being accurately captured in the total-company NPC analysis. Washington is not concerned, for example, with the cost of PacifiCorp's coal and gas plants allocated to other states, nor how those impact total-Company NPC. Notwithstanding, the modeling assumptions used for those non-Washington resources have the potential to produce major impacts on the costs and benefits of Washington

resources through the spreadsheet method. Therefore, as an overarching criteria for evaluating the reasonableness of the total-company NPC, the principal consideration should be whether it accurately captures the costs and benefits of Washington-allocated resources.

a. Net Power Cost Categories

Q. WHAT IS NPC?

A. NPC represents the variable energy costs associated with providing electric services. NPC includes the cost of fuel (both coal and gas), the cost of purchased power, and the cost of wheeling (i.e., the cost of transmitting electricity on other utilities' transmission systems). It also includes the revenues associated with power sales in wholesale markets. The net in NPC is representative of the fact that it includes wholesale sales transactions, which offset the variable energy costs of serving retail customers. The specific FERC Accounts included in NPC are as follows:

- Account 447 – Sales for Resale;
- Account 501 – Fuel (for Steam Power);
- Account 503 – Steam from Other Sources (Geothermal);
- Account 547 – Fuel (for Mechanical Power);
- Account 555 – Purchased Power; and
- Account 565 – Wheeling.

Q. HAS PACIFICORP PROPOSED EXPANDING THE DEFINITION OF NPC IN THIS CASE?

A. Potentially. When PacifiCorp provided its definition of NPC, it included a FERC account, Account 509 – Allowances. Allowances in Account 509, such as sulfur dioxide and CO_2 allowances, have historically not been considered an item of NPC. In the 2023 GRC, PacifiCorp expressly excluded allowances from NPC.[15] Moreover, in response to AWEC Data Request 34 in this case, PacifiCorp also confirmed that it did not include CCA allowance costs in the PCORC filing in this case.[16] Thus, PacifiCorp's purpose for modifying the definition of NPC in this case, if it is at all, is not entirely clear.

Q. DID FERC CHANGE THE ACCOUNTING FOR ALLOWANCES IN ORDER 898, WHEN IT MODIFIED THE UNIFORM SYSTEM OF ACCOUNTS?

A. No. With respect Carbon Dioxide ("CO_2") allowances, FERC's longstanding accounting guidance has been that CO_2 Allowances were to be recorded in Account 509. In **Mullins, Exh. BGM-4**, for example, I provide documentation from Arizona Public Service that as far back as 2012 the guidance of FERC's Chief Accountant was that CO_2 allowances were to be recorded in Account 509. While historically the description of Account 509 only identified Sulphur Dioxide ("SO_2") Allowances, per the 1990 Clean Air Act, it became accepted practice to include other environmental allowances, such as CCA CO_2 allowances, in that account. At the time Account 509 was established in 1993, CO_2 allowances did not exist, [17] and using Account 509 to record the cost of all environmental

15 Docket No. UE-230172, Exh. BGM-1CT at 39:7-11.

16 Mullins, Exh. BGM-3 (PacifiCorp's Resp. to AWEC DR 34).

17 Revisions to Uniform Systems of Accounts to Account for Allowances Under the Clean Air Act Amendments of 1990 and Regulatory-Created Assets and Liabilities and to Form Nos. 1, 1-F, 2 and 2-A,

allowances became the accepted practice, despite the account description being limited to SO_2. In FERC Order 898, however, FERC made an overhaul to the Uniform System of Accounts. As one of the changes, FERC changed the description of Account 509 to be more generic and to conform with its longstanding practice of including the cost of both SO_2 and CO_2 allowances in that account. Thus, the name change was simply codifying the currently accepted practice, not a change accounting classification for CO_2 allowances.

Q. DO YOU SUPPORT CHANGING THE DEFINITION OF NPC TO INCLUDE ACCOUNT 509, ALLOWANCES?

A. Not at this time. First, it is not clear if PacifiCorp is actually requesting a change to the definition of NPC, nor whether it is potentially proposing that allowance costs be considered and trued up in future PCAM filings. If that is the proposal in this case, however, AWEC recommends it not be considered. The treatment of allowances, including the distribution of no-cost allowances, is complicated and all of the details associated with no-cost allowances have not yet been resolved by the Department of Ecology. Further, it is possible that PacifiCorp's other states will be required to purchase allowances when transacting at the Mid-Columbia market hub. Making sure that those allowances do not get allocated to Washington customers should be another concern, but until the full scope of the allowances PacifiCorp proposes to be included in NPC (which, again, in this case are none) is known, it is difficult to form any findings regarding the reasonableness of potentially changing the definition of NPC to include Account 509.

Order No. 552, 58 FR 17982 (April 7, 1993), FERC Stats. & Regs. ¶ 30,967 (1993) (cross-referenced at 62 FERC ¶ 61,299).

b. Aurora Version 16

Q. WHAT AURORA MODEL VERSION DID YOU USE IN YOUR ANALYSIS?

A. I used Aurora version 16.0.1001, which was the version available on Energy Exemplar's website at the time I received access to the model. In contrast, PacifiCorp's filing was based on an earlier version 15.0.1016.

Q. DID THE USE OF A NEWER VERSION IMPACT THE CALCULATION OF NPC?

A. Yes. Using the newer version increased total-company NPC by approximately $25,071, an immaterial change. On a Washington-allocated basis, however, the change was a $1,276,787 increase. Only slight changes to the model logic algorithms were made between the two versions, and while they produced nearly identical total-company NPC, the change in the dispatch profile for Washington allocated resources, resulted in a material increase to Washington-allocated NPC. This was perplexing, and I was unable to fully explain the difference. One of the factors leading to the higher Wasington-allocated NPC that I did identify was additional curtailments of wind production, which I discuss below.

c. Wind Production Penalty

Q. HOW IS PACIFICORP PENALIZING THE WIND PRODUCTION ALLOCATED TO WASHINGTON?

A. Having access to zero-carbon, zero-cost energy from renewable resources in PacifiCorp's Eastern BAA was a principal consideration in Washington's decision to depart from the WCA method and to adopt the WIJAM in the 2020 Protocol.[18] It is also vital to

[18] Docket No. UE-191024, Order 09 at ¶ 99 (Dec. 14, 2020).

Washington's ability to satisfy the requirements of CETA. In its filing, however, PacifiCorp has used a modeling method that imposes major penalties on the amount of wind production that is allocated to Washington customers. Complicating matters, a significant portion of these dispatch penalties are being modeled to allow for uneconomic increases to output from coal plants in order to avoid certain liquidated damages obligations under new coal supply agreements, the cost of which must be excluded from Washington rates. This modeling penalty on wind production, appears to be related to a modeling change PacifiCorp introduced in the 2023 GRC, which it referred to then as a change to "Trapped Energy."[19] The severe implications of this method on the costs and the emissions allocated to Washington's resource portfolio, however, was not clearly articulated in that filing. In this case, PacifiCorp's modeling change increases Wasington-allocated NPC by $11,668,822 and reduces Washington-allocated PTCs by $7,382,988. I recommend that these penalties on Washington's non-emitting wind portfolio be eliminated from Washington rates. After considering the production factor impacts, this recommendation reduces PCORC revenue requirement by approximately $19,566,055.

Q. HOW DID YOU DISCOVER THIS ISSUE?

A. Based on the testimony that was filed in the 2023 GRC, I was unaware of the magnitude and significance of the "Trapped Energy" modeling change PacifiCorp had proposed. In this case, I performed a comparison between the wind production forecasts PacifiCorp inputs into the Aurora model to the wind production included in Washington-allocated

[19] Docket No. UE 230172, Mitchell, Exh. RJM-1CTr at 28:3-31:7.

NPC. That analysis showed large discrepancies, which were not present in the 2023 GRC, indicative of a wind production penalty being imposed on Washington customers' investment in non-emitting resources. That comparison is provided in **Confidential Table 2**, below, which compares PacifiCorp's wind production forecasts to the Aurora model output.

Confidential Table 2
PacifiCorp Modeled Wind Capacity Factors vs. Modeled Output (Total-Company)

Confidential Table 2 compares the modeled wind capacity factors that PacifiCorp inputs into Aurora with the output from the Aurora model dispatch. I had

expected these two values—the modeled input and the modeled output—to be the same or at least similar, but when I reviewed the results of this analysis, there were major differences, the magnitude of which was surprising. As can be seen from **Confidential Table 2**, PacifiCorp's modeling approach in this case resulted in curtailment of [redacted]% of wind production relative to the wind production forecasts that were input into the Aurora model. Not only that, it resulted in the loss of [redacted] MWhs of carbon-free energy and the associated PTCs. The lost PTCs alone are worth $[redacted] on a total-company basis. Thus, not only does this modeling method penalize Washington customers through increased costs, but it also has major impacts on Washington-allocated emissions and Washington's clean energy policies, including CETA. Using a 0.437 $MTCO_2e$/MWh unspecified power rate for the lost energy, this modeling approach equates to a potential [redacted] MT of CO_2e increase to system wide greenhouse gas emissions. In the model, however, a major part of these wind curtailments is being caused by increased output and constraints on coal resources of other states, which as I discuss further below, means that the negative environmental impacts of this modeling approach are likely even worse.

Q. HOW DOES PACIFICORP FORECAST WIND PRODUCTION?

A. PacifiCorp's method for forecasting wind production is based on static, hourly wind production profiles, which it inputs into the Aurora model. PacifiCorp's method for deriving these wind production profiles was described in response to AWEC Data Request 11, as follows:

> For resources that had four years of historical data as of December 31, 2023, the Company used 48 months of historical data to calculate the forecast

> capacity factor (CF). For resources that did not have four years of historical data as of December 31, 2023, the Company used the pre-construction vintage CFs.[20]

PacifiCorp later clarified that the "pre-construction vintage CFs" are the same as what are known as the "P50 capacity factors," which are the production amounts PacifiCorp forecast when it presented its investment in the underlying resources for Commission approval.[21] The P50 capacity factors were developed using engineering studies of the wind potential at the various wind sites prior to their development. "P50" refers to the fact that it was expected that the production would be higher than the estimate 50% of the time and lower than the estimate 50% of the time. As PacifiCorp has explained "[t]he P50 forecast reflects the generation amount that, under the conditions and assumptions included in the analysis, would be expected to be exceeded 50 percent of the time, and, conversely, not exceeded 50 percent of the time."[22] PacifiCorp provided AWEC with the P50 capacity factors in response to AWEC Data Request 10.[23]

Confidential Table 3, below details the forecast used by PacifiCorp in relation to the P50 capacity factors.

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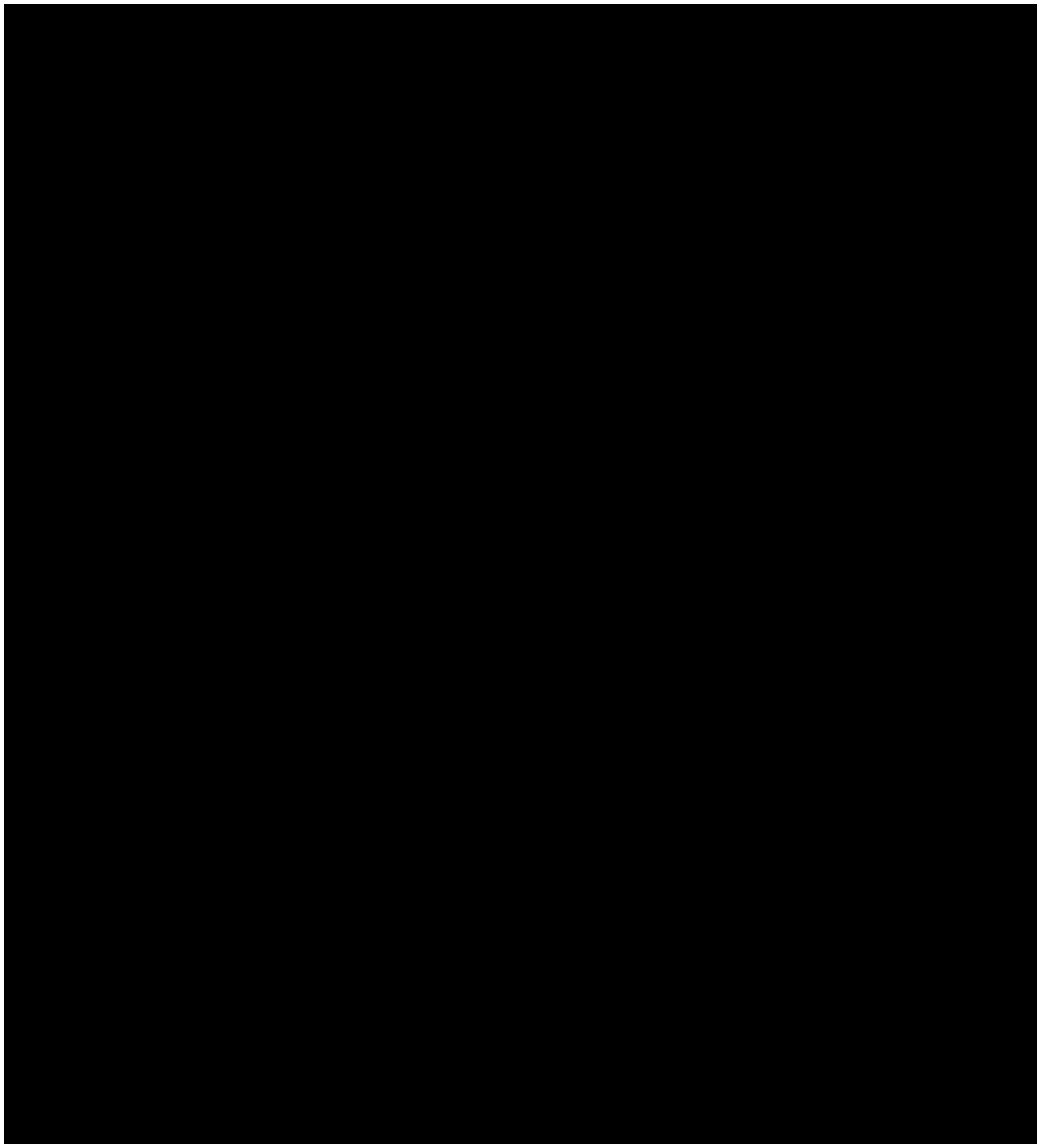
20 Mullins, Exh. BGM-3 (PacifiCorp Resp. to AWEC DR 11).

21 *Id.* at (PacifiCorp Resp. to AWEC DR 45).

22 Wy. PSC Docket No. Docket No. 20000-664-EM-24, Rebuttal Testimony of Timothy J. Hemstreet at 8:10-12.

23 Mullins, Exh. BGM-3 (PacifiCorp Resp. to AWEC DR 45).

Confidential Table 3
P50 Capacity Factor vs Capacity Forecast Input into Aurora



Confidential Table 3 provides a comparison between the capacity factor forecast that PacifiCorp inputs into the Aurora Model and the P50 capacity factors provided in response to AWEC Data Request 10. I have also detailed the method that PacifiCorp used for its wind forecast, whether it be based on the P50 capacity factor or 48 months of historical data. As can be seen from the **Confidential Table 3**, in PacifiCorp's forecast,

approximately 65% of the wind fleet (measured by nameplate capacity) relies on the P50 capacity factors, with approximately 35% relying on a historical, 4-year average. There were some differences between the P50 capacity factors provided in response to AWEC Data Request 10 and the P50 capacity factors PacifiCorp input into Aurora. Most of these variances were minor, falling within a few tenths of a percent, and AWEC does not contest them.

Q. DOES AWEC SUPPORT USING PACIFICORP'S FORECAST CAPACITY FACTORS IN THIS CASE?

A. AWEC does not oppose using PacifiCorp's forecast capacity factors, as identified in **Confidential Table 3,** in this proceeding. In general, AWEC is willing to support the forecast because PacifiCorp has continued using the P50 production forecast for new wind resources, constituting the majority of its wind fleet. AWEC is concerned, however, that repowered wind resources have experienced lower production than forecast at the time that investment in them was undertaken, although since the majority of the wind resources continue to rely on the P50 production estimate AWEC does not oppose PacifiCorp's forecast.

Q. WHY IS IT IMPORTANT TO RELY ON THE P50 CAPACITY FACTORS FOR NEW RESOURCES?

A. AWEC has observed that for the new wind resources, actual production has been lagging the P50 capacity factors, at least in the initial few years of those resources' lives. With only a few years of operational experience with PacifiCorp's new wind and repowering investments, however, there is not yet sufficient data to conclude that the pre-construction estimates were inaccurate. As PacifiCorp has explained "it is entirely within expectations

that there will be periods – often multiple years in a sequence – during which wind speeds will be below a long-term average."[24] PacifiCorp has also asserted that a 3-4 year period is inadequate to prove the inaccuracy of the P50 forecast, stating "it is unreasonable to expect that P50 forecast generation values will be realized in so short of a time as the three- to four-year operational history of some of the new and repowered wind projects."[25] Thus, AWEC recommends that the P50 capacity factors continue to be used, at least for new wind resources, regardless of the recent history, until such a time that a concrete determination can be made that the P50 capacity factors are inaccurate. Yet, if it is concluded that those pre-construction estimates were inaccurate, further investigation needs to be undertaken. The pre-construction production forecasts were used as the basis for investing many billions of dollars in new wind and transmission assets across the west. To the extent that it is now believed that those production forecasts were wrong, that calls into question the efficacy of PacifiCorp's planning for those resources as well as the request for proposal process. In the past, PacifiCorp has committed to using the pre-construction forecasts as the basis for ratemaking, and I see no reason why that should not continue to be the case going forward. Since PacifiCorp has effectively committed to continue using those pre-construction forecasts for new wind in this case, however, AWEC does not oppose PacifiCorp's approach, nor its forecast capacity factors, as detailed in **Confidential Table 3.**

[24] Wy. PSC Docket No. Docket No. 20000-664-EM-24, Rebuttal Testimony of Timothy J. Hemstreet at 15:18-20.

[25] *Id.* at 15:20-22.

Q. IS PACIFICORP'S WIND CURTAILED IN ACTUAL OPERATIONS?

A. Yes. PacifiCorp has stated that "the Company has no contractual rights to dispatch much of the capacity of contracted wind projects for economic reasons, requiring the Company to curtail its own generation resources – including wind resources – when there is an oversupply of energy on the system."[26] In response to AWEC Data Request 9, PacifiCorp provided the curtailment history for its wind fleet over the period 2019 through 2024. In response to AWEC Data Request 48, PacifiCorp confirmed that 100% of the curtailments included in the Response to AWEC Data Request 9 were initiated through dispatch instructions issued by the CAISO Western Energy Imbalance Market ("WEIM") in the five-minute instructed imbalance market.

Q. ARE THE WEIM DISPATCH INSTRUCTIONS DISTINCT FROM THE CURTAILMENTS PACIFICORP PROPOSES IN WASHINGTON RATES?

A. Yes. Unlike the curtailments modeled in Aurora, PacifiCorp is paid to receive, and provided with, replacement energy when it responds to WEIM dispatch instructions for wind resources. Thus, the historical WEIM 5-minute negative imbalances for wind resources (i.e. curtailments), are distinct from the hourly curtailments in Aurora, which result in lost carbon-free energy and lost PTCs, without any replacement energy or recompensation.

Q. HOW DOES THE HISTORICAL WEIM DISPATCH COMPARE TO THE CURTAILMENTS PACIFICORP MODELED IN AURORA?

A. In **Confidential Mullins, Exh. BGM-5C,** I provide an analysis comparing the wind curtailments PacifiCorp modeled in Aurora to the historical WEIM 5-minute negative

[26] *Id.* at 10:13.

dispatch instructions. That analysis shows that PacifiCorp has modeled a level of curtailments of Wyoming wind in Aurora that is [redacted] *times* higher than the historical wind dispatch initiated through the WEIM. For Columbia River Gorge wind, the variance is even greater. The Aurora curtailments are [redacted] *times* the historical WEIM wind feathering dispatch. On a total system basis, the CAISO WEIM initiated economic curtailments equivalent to [redacted] of PacifiCorp's owned wind fleet output over the period 2020-2024, yet PacifiCorp's modeling in Aurora results in curtailment of [redacted] of the output from those same resources ([redacted] for Wyoming Wind and [redacted] for Gorge Wind). This variance is shown graphically in **Confidential Figure 1**, below.

Confidential Figure 1
EIM Wind Curtailment vs. Aurora Forecast

Q. HOW DOES PACIFICORP RECEIVE REPLACEMENT ENERGY FOR WEIM CURTAILMENT INSTRUCTIONS?

A. When a wind plant is instructed to curtail output from the WEIM, the market provides replacement energy in the form of imbalance energy. Like any resources in the WEIM,

wind is bid into the market at a certain price, and the market will only instruct a negative imbalance and provide replacement imbalance energy if the locational market price is less than the bid price for the wind resource. Since there is no energy cost associated with wind energy, the locational market price must be negative to justify curtailing wind, in which case PacifiCorp would receive an economic settlement payment in connection with the receipt of replacement energy from the EIM for the wind curtailment. The dispatch price that wind is assigned in the WEIM depends on whether a curtailment will result in the loss of PTCs. If PTCs are an issue, the locational price will have to be sufficiently negative to justify the loss of PTCs. Accordingly, apart from the glaring inconsistency between the historical WEIM data and the curtailments modeled in Aurora, PacifiCorp is not harmed economically as a result of the historical WEIM curtailments, and in fact benefits, because it is paid to receive replacement energy from the market. In contrast, through its Aurora modeling, PacifiCorp is forecasting major negative economic consequences as a result of wind curtailments. On a total Company basis, the curtailments PacifiCorp is forecasting result in a $102,880,120 increase in NPC and the loss of $79,816,239 in PTCs, a total economic cost of approximately $182,752,594 on a total-Company basis. This compares to assumed EIM dispatch benefits in NPC of $117,443,469,[27] which are the benefits of PacifiCorp's entire fleet.

[27] See 250244-PAC-RJM-TCDirect 4-1-2025 (C), Tab "EDAM and EIM", Cell "P2".

Q. ARE THE HISTORICAL WEIM CURTAILMENTS ALREADY CONSIDERED IN THE CAPACITY FACTORS INPUT INTO AURORA?

A. Yes. From **Mullins, Exh. BGM-5C**, approximately [redacted]% of the historical WIEM curtailments were to wind output from repowered wind resources. As noted in **Confidential Table 3**, above, PacifiCorp used historical wind production as the basis for the forecast capacity factors for those resources. The historical data that PacifiCorp used to calculate those capacity factors is the actual production net of curtailments, which already includes the cost impact of WIEM curtailments. By using historical data, PacifiCorp has already implicitly incorporated the cost of the curtailment into its modeling. PacifiCorp has stated:

> "[S]ystem balancing often requires that wind output be curtailed as the most economic means to bring the system into balance. Thus, the Western Energy Imbalance Market in which the Company participates will provide curtailment signals to the Company's generation facilities, including its wind resources, to achieve system balancing most cost-effectively. Economic curtailment such as this is not considered in a pre-construction P50 forecast, so EIM curtailment directives – even though cost effective – will cause the generation output from a wind project to deviate from a preconstruction P50 forecast – which does not consider economic curtailment."[28]

Thus, because PacifiCorp uses historical data in its capacity factor forecast, the historical WEIM curtailments are already implicitly reflected in its forecast.

Q. WERE WIND CURTAILMENTS EXPECTED TO BE ELIMINATED FOLLOWING THE CONSTRUCTION OF GATEWAY SOUTH?

A. Apart from the fact that PacifiCorp receives negative-priced replacement energy for the WEIM curtailments, the construction of Gateway South was expected to, and in fact, has

[28] Wy. PSC Docket No. Docket No. 20000-664-EM-24, Rebuttal Testimony of Timothy J. Hemstreet at 11:9-16.

largely eliminated curtailments. The purpose of Gateway South was to "reliev[e] congestion on the transmission system, enable[e] additional renewable resource interconnections, and improv[e] overall reliability."[29] A major part of that benefit was the reduction of wind curtailment. In its Application for Reconsideration in Oregon Public Utility Commission ("OPUC") Docket No. UE 433, for example, PacifiCorp asserted that "[s]ince Gateway South went into service in December 2024, the volume of Wyoming wind curtailment has dropped sharply, from 11.87 percent of total wind generation before Gateway South to 0.11 percent after Gateway South."[30] PacifiCorp made similar statements in OPUC Docket No. UE 451, stating that "Gateway South greatly reduced wind curtailments even though an additional 481.5 MW of Wyoming wind resources became operable at the end of 2024 that was not online during the directly comparable study period in 2023/2024."[31] Thus, by modeling the excessive amount of curtailments noted above, PacifiCorp is diluting, if not eliminating, Washington ratepayers' benefits in their major investment in Gateway South.

Q. ARE THE AURORA CURTAILMENTS PHYSICAL TRANSMISSION LIMITS IN THE MODEL?

A. No. In response to a similar recommendation made in Oregon, PacifiCorp stated "[t]he Company's Aurora model curtails wind only when transmission constraints prevent delivery of wind generation to load, consistent with actual operations."[32] These types of

29 Docket No UE 433, Pac/200 McVee/7:18.

30 Oregon PUC Docket No. UE 433, PacifiCorp's Application for Reconsideration or Rehearing at 11-12 (Feb. 18, 2025) (internal citations omitted).

31 Oregon PUC Docket No. UE 451, PAC/300 Link/10:3-5 (internal citations omitted).

32 Oregon PUC Docket No. UE 450, PAC/500 Mitchell/24:7-9.

assertions, however, are not credible and should be given zero weight by the Commission. There is ample transmission capability in the model, even when curtailments are being modeled. This is particularly true given the inclusion of the Gateway South capacity in the model. I was able to demonstrate this through a modeling approach, discussed below, which considers the same transmission constraints, while still allowing for the delivery of wind output. While transmission constraints do impact pricing in the WEIM and influence whether curtailment instructions are issued to wind plants, transmission constraints are not the cause of the extraordinary large volume of wind curtailments in PacifiCorp's Aurora modeling.

Q. WHAT IS THE MODELING THAT YOU PERFORMED TO DEMONSTRATE TRANSMISSION IS NOT AN ISSUE?

A. I performed modeling that treated all non-emitting resources as "must-run" resources. This modeling was subject to the same transmission constraints as PacifiCorp uses, while still producing substantially lower NPC. On a total-Company basis, this approach reduced PacifiCorp's total-Company cost by $182,752,594 (including PTCs), while still meeting the same transmission constraints. In other words, the curtailments PacifiCorp modeled were uneconomic and produced a substantial increase to total-system costs. The fact that much of the wind curtailments PacifiCorp modeled also occurred in areas that are typically not subject to physical transmission constraints, such as the Columbia River Gorge Wind, is yet another reason why it is clear that transmission constraints are not the cause.

Q. SHOULD WASHINGTON RATEPAYERS GET 100% OF THE VALUE FROM THE NON-EMITTING RESOURCES THEY HAVE INVESTED IN?

A. Yes. Regardless of the modeling complications, as general principle Washington ratepayers should get full value and 100% of the non-emitting energy from the renewable resources that they have invested in. These resources, therefore, should be modeled in a way that eliminates unnecessary and costly wind curtailments. Notably, to the extent that curtailments are necessary in the total-company NPC modeling, it is due to the fact that they are benefiting other states, not Washington customers, and should be reversed through the Washington-allocated NPC on that basis as well.

Q. WHAT IS CAUSING THE LARGE VOLUME OF CURTAILMENTS IN AURORA?

A. The cause of the curtailment appears to be driven principally by systemwide oversupply in the model, with no ability to sell or market the excess power. The largest driver of this appears to be constraints modeled surrounding coal-fired resources, as well as new situs-assigned solar resources that are being directly assigned to Utah, under green tariff arrangements of that state. There are also several conflicting self-imposed modeling limitations, meant to reduce the model's flexibility, which impact the curtailments. For example, as discussed earlier, PacifiCorp eliminated the use of "trapped energy" in the 2023 general rate case, which was a long-standing method going back to PacifiCorp's use of GRID to model power costs. Overly restrictive market capacity limits, coupled with pre-hedging transactions, also appear to have exacerbated this problem. There also appear to be instances where the model is uneconomically relying on market purchases at the same time as curtailing wind, when it could have otherwise not made the market

purchase, indicating a problem with the commitment logic that PacifiCorp is using. The model is full of so many different techniques designed by PacifiCorp to increase modeled cost that it becomes difficult to track how they interact—Market Caps, DA/RT Adjustment, Unspecified Purchases, Prehedging Transactions, Trapped Energy, and coal supply constraints.

Q. WHAT ARE THE COAL SUPPLY CONSTRAINTS THAT PACIFICORP MODELS?

A. Coal fuel supply constraints, including those related to Hunter and Huntington, were perhaps the largest contributor to the oversupply and the wind curtailments that were observed in PacifiCorp's model. PacifiCorp has take-or-pay contracts with third-party suppliers to its coal generation facilities that require PacifiCorp to purchase a minimum amount of coal or pay liquidated damages. To avoid paying liquidated damages in modeled NPC, PacifiCorp forces the model to dispatch enough coal to use at least the minimum supply quantity. This is done through specified constraints input into Aurora that impose floors and caps on the output of coal plants in order to satisfy the minimum and maximum coal supply limits in the contracts. There are several problems with this approach that I discuss below, including the fact that Aurora considers the constraint on an hourly basis, in a manner that severely restricts its ability modify the output to respond to changes in renewable energy production. It also assumes that PacifiCorp will never decide to stockpile coal, or that it will never decide to pay liquidated damages, in order to avoid uneconomically curtailing wind resources.

Q. HOW DO COAL SUPPLY CONSTRAINTS IMPACT WIND CURTAILMENTS IN MODELED DISPATCH?

A. I performed a scenario where I removed the fuel supply constraints, and instead allowed the model to dispatch coal based on the incremental cost of its coal supplies. I also performed a calculation that assumed PacifiCorp would pay liquidated damages to its coal suppliers if the minimum take obligations were not satisfied by the model. The price of coal in NPC continued to use the actual costs of PacifiCorp's fuel contracts, in the same manner as PacifiCorp modeled those costs, only the modeled constraints were removed. In this scenario, PacifiCorp's modeled wind curtailments declined by [redacted]%. Thus, the coal supply constraints in the new contract amendments that PacifiCorp has recently executed are having a major impact on the amount of renewable energy that PacifiCorp is able to deliver to Washington customers, as well as its progress towards CETA requirements.

Q. DO WASHINGTON CUSTOMERS BENEFIT FROM HUNTER AND HUNTINGTON?

A. No. Notwithstanding the fact that all coal must be removed from PacifiCorp's rates as of the rate effective date of this case, Washington customers have never benefitted from Hunter and Huntington – these plants have never been in Washington rates. Therefore, the Commission should not approve an NPC forecast that includes wind curtailments that enable PacifiCorp to uneconomically increase output and emissions from its coal fleet allocated to other states.

Q. HOW HAVE THE UTAH GREEN TARIFF PROGRAMS IMPACTED THE CURTAILMENTS IN AURORA?

A. PacifiCorp's total company NPC includes several solar PPA contracts that were procured under certain Utah green tariff programs. Washington does not benefit from those contracts, and the costs and benefits of those contracts should be situs assigned to Utah, both under the 2020 Protocol and the new 2026 allocation methodology PacifiCorp has proposed.[33] Notwithstanding, the excess supply created by those contracts is also a significant driver of the modeled curtailments in Aurora. If those contracts are eliminated from the total-company NPC calculation, the curtailments decline by 13%.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION.

A. I recommend that PacifiCorp's wind fleet be modeled based on the capacity factors input into Aurora, without the extensive level of curtailments noted above. I performed a scenario where I modeled wind resources as "must-run" resources, limiting the model's ability to treat them as dispatchable. My adjustment results in a $11,668,822 reduction to Wasington-allocated NPC and a $7,382,988 increase to Washington-allocated PTCs. After considering the production factor impacts, my recommendation results in a total reduction to PCORC revenue requirement of $19,566,055.

[33] 2020 Protocol § 5.8; Mullins, Exh. BGM-7 at 11 (2026 Protocol § 3.7).

d. BPA Real Power Losses

Q. PLEASE SUMMARIZE THE ISSUE YOU HAVE IDENTIFIED FOR BPA REAL POWER LOSSES.

A. In its BP-24 general rate case, BPA changed the way that real power losses associated with the use of its transmission system were handled.[34] In BP-24, BPA implemented more stringent requirements surrounding the way that power losses were required to be settled, requiring physical losses to be settled concurrently.[35] My understanding is that previously losses were settled over the course of a billing cycle in conjunction with imbalances, but with BPA joining the EIM, it also changed its approach for handling in-kind loss returns. As a result of this change, in March 2024, PacifiCorp transitioned from In-Kind Loss Return Service (i.e. physical loss returns) to financial settlement of real power losses.[36] Based on this change, PacifiCorp also added a new wheeling charge into its NPC forecast of $[redacted] on a total-Company basis.[37] The cost of these transmission losses, however, have historically been reflected in PacifiCorp's load forecast, and based on my review, PacifiCorp has not modified its load forecasting approach to reflect this change. Therefore, considering the cost of financially settled losses as a component of PacifiCorp's wheeling expense forecast overstates NPC because the costs of BPA losses are already reflected as losses in its load forecast. Accordingly, I recommend the new wheeling cost item be removed from forecast NPC in this case.

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34 This change continued in BPA's BP-26 rate case proceeding, with no proposed changes to the treatment for real power losses.

35 BP-24-E-BPA-09 at 5:4-10.

36 Mullins, Exh. BGM-3 (PacifiCorp's Resps. to AWEC DRs 31 & 32).

37 See Workpaper 250224-PAC-RJM-GNwWheeling-4-1-25(C), Tab "WheelingCosts," Cell "I171".

Q. WHAT ARE REAL POWER LOSSES?

A. As power flows across a transmission system, a certain amount of power is lost due to resistance and impedance on the conductors and equipment involved conveying electrical energy. For BPA, it's Open Access Transmission Tariff assumes that 2.04% (September through May) and 2.09% (June through August) of energy transmitted on its electrical system is lost.[38] Accordingly, if a transmission customer delivers 100 MWh of electrical energy onto BPA's transmission system, approximately 2 MWh (rounding to the nearest MWh) of that power will be lost and not deliverable to the customer's point of receipt. This represents a cost to BPA, which must be considered in the rates for services that it provides to its transmission customers.

Q. HOW DO TRANSMISSION SERVICE PROVIDERS RECOVER THE COST OF REAL POWER LOSSES?

A. There are at least two different methods that transmission providers use to recover the cost of real power losses. One way is through "in-kind" or physical loss return, where a transmission customer schedules more power to the transmission system than it intends to receive to compensate for the losses. The other is through financial settlement, where the transmission customer pays the transmission service provider for the market value of power that was lost in connection with its services.

Q. PLEASE PROVIDE AN EXAMPLE OF PHYSICAL LOSS RETURN.

A. Assuming a 100 MWh transfer and a 2% loss rate, under physical loss return, a transmission customer would deliver 102 MWh of power to the transmission system and

[38] Bonneville Power Administration, Open Access Transmission Tariff, Schedule 11, at 137 (June 30, 2024).

subsequently take delivery of 100 MWh of power at its point of receipt, thus compensating for losses. This is the principal method that PacifiCorp used on BPA's system prior to March 2024, when it transitioned from physical to financial settlement of real power losses.

Q. PLEASE PROVIDE AN EXAMPLE OF FINANCIAL LOSS SETTLEMENT.

A. Using the same example, the transmission customer would schedule 100 MWh of power to the transmission system and subsequently receive 100 MWh of power at its point of delivery. To compensate for losses, however, it also would pay the transmission provider for the market value of 2 MWh of power at whatever the market index rate was. If the market index rate was $50/MWh, this would amount to a $100 payment for losses from the transmission customer to the transmission service provider in connection with the 100 MWh transfer. This is the method that PacifiCorp now uses on BPA's system. Note, however, that BPA also includes a capacity charge in addition to a market rate in its calculation of the financial value of real power losses.

Q. DID PACIFICORP ACKNOWLEDGE THAT IT CHANGED SERVICES?

A. Yes. In response to a discovery request in Oregon Docket No UE 450, PacifiCorp noted the following:

> BPA loss return charges are financial costs incurred by the Company for real power losses associated with scheduling energy on PacifiCorp's long-term and short-term transmission BPA reservations, pursuant to Schedule 11 of BPA's OATT (Section 15.7). Historically, the Company returned these losses physically (energy sent to BPA). Beginning March 2024, the Company began settling these losses financially. As it concerns PacifiCorp's usage of BPA transmission, financial loss settling is lower cost than returning losses physically.[39]

[39] Mullins, Exh. BGM-3 (PacifiCorp's Resp. to AWEC DR 16 in Oregon Docket No. UE 450).

Q. WHAT ISSUES HAVE YOU IDENTIFIED WITH PACIFICORP'S FORECAST OF BPA REAL POWER LOSSES?

A. As noted, PacifiCorp has included a new line item in its wheeling expense calculations for financially settled BPA real power losses. There are two issues that I identified with these amounts. First, PacifiCorp already considers BPA real power losses in its load forecast, and therefore, it is unnecessary to consider the value of losses reimbursed to BPA through wheeling expense. Second, PacifiCorp used historical financial losses as the basis for its forecast. This approach is inaccurate because the market prices will have changed between the historical period and the forecast period resulting in a different value for losses settled in the forecast period than the historical period.

Q. HOW DOES PACIFICORP CONSIDER LOSSES IN ITS LOAD FORECAST?

A. The load forecast PacifiCorp uses in NPC is based on its load at the generator input level. It includes a forecast of its retail sales at individual customer meters, plus a provision for losses. In other words, the load forecast includes not only the MWhs necessary to serve PacifiCorp's customers' load requirements, but also the losses associated with serving those customers. To perform its forecast, PacifiCorp includes a projection of its retail sales based on various statistical analyses and then grosses up those values using a loss factor. PacifiCorp was asked to explain how line losses were calculated in its load forecast. In response, PacifiCorp stated the following:

> Line losses are added to PacifiCorp's sales forecast to produce the load forecast. Once line losses are added to test period retail sales by jurisdiction to produce jurisdictional load, it is then transformed to hourly loads.[40]

[40] *Id.* at (PacifiCorp's Resp. to AWEC DR 34 in Oregon Docket No. UE 450).

Q. WHAT LINE LOSS FACTORS DOES PACIFICORP USE?

A. In AWEC Data Request 30, PacifiCorp was requested to provide workpapers supporting the line loss calculations included in its load forecast.[41] In response, PacifiCorp provided an excel workbook that contained line loss factors applied for each of its jurisdictions, and along with the requested workpapers. In response to AWEC Data Request 29, PacifiCorp explained that the loss factors were calculated based on actual losses measured over the period 2019 through 2023:

> The Company calculates line losses as the five-year average of annual load at input (generation) divided by annual retail (sales). Please refer to Attachment AWEC 029 which provides the loss factors and the associated work paper used in the load forecast in this 2026 power costs only rate case (PCORC) proceeding..[42]

It was confirmed through an evaluation of the line loss workpapers that were provided in response to AWEC Data Request 29 that the five-year calculation was performed over the period 2019 through 2023.[43]

Q. DID THE LOSS FACTORS IN PACIFICORP'S LOAD FORECAST CONSIDER THE TRANSITION TO FINANCIAL LOSS SETTLEMENT FOR BPA?

A. No. PacifiCorp's load forecast was prepared in mid-2024, using data from 2019 through 2023.[44] At that time, the data that PacifiCorp relied upon to develop its forecast, and its line loss factors, did not consider the transition to financial settlement of BPA losses. In the response to AWEC Data Request 29, no adjustment was applied to reflect the transition to financial loss settlement through BPA. Accordingly, the load forecast

41 *Id.* at (PacifiCorp's Resp. to AWEC DR 30).
42 *Id.* at (PacifiCorp's Resp. to AWEC DR 29).
43 *Id.*
44 *Id.*

continued to assume that the physical losses associated with power transmitted on BPA's system would to be settled in-kind, i.e. physically. In other words, physical BPA losses are already considered in the load forecast and the system costs associated with those losses are already reflected in NPC.

Q. WHAT IS YOUR RECOMMENDATION FOR BPA REAL POWER LOSSES IN THIS PROCEEDING?

A. Because BPA real power losses are already considered in the loss factors used in the load forecast and already reflected in NPC, my recommendation is that the wheeling charge for BPA real power losses that PacifiCorp included in its NPC forecast be removed from NPC. PacifiCorp asserted that financial settlement of losses was less expensive than physical settlement of BPA losses. In response to AWEC Data Request 32, PacifiCorp stated "that financial settlement of losses could lower costs by settling for losses with BPA at the hourly Load Aggregation Point (LAP) price."[45] This means that the BPA real power losses embedded in the load forecast result in more cost in NPC than if they were to be removed from the load forecast and considered solely through wheeling expense. Thus, continuing to include BPA real power losses in the load forecast is a reasonable approach, and will not result in PacifiCorp under-recovering its costs.

Q. HAS PACIFICORP ACCEPTED YOUR RECOMMENDATION IN OTHER PROCEEDINGS?

A. Yes. In Oregon Docket No UE 450, PacifiCorp's Oregon Transmission Adjustment Mechanism filing, PacifiCorp accepted this change to its NPC forecast.[46] PacifiCorp

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45 Mullins, Exh. BGM-3 (PacifiCorp's Resp. to AWEC DR 32).

46 Or.PUC Docket No UE 435, PAC/500, Mitchell/6:15-17.

stated, "the Company recommends that the Commission adopt AWEC's recommendation from their testimony which involves removing the financial costs of BPA real power losses included in a wheeling expense line item in the NPC forecast."[47]

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. The impact of this recommendation is a $[redacted] reduction to total-company NPC, with $[redacted] allocated to Washington. After applying the production factor, this change produces a $1,643,175 reduction to PCORC revenue requirement.

e. BP-26 Rate Case

Q. PLEASE SUMMARIZE THE ISSUE YOU IDENTIFIED WITH RESPECT TO THE BP-26 RATE CASE?

A. The Bonneville Power Administration has recently concluded the BP-26 rate case, which resulted in an approximate 24.0% increase to Point-to-Point transmission rates.[48]

Q. HAS PACIFICORP CONSIDERED THIS IMPACT IN ITS NPC IN THIS CASE?

A. No. At the time PacifiCorp made its filing in this case, the magnitude of the rate increase was known based on the initial proposal that was filed in November 2024. Notwithstanding, PacifiCorp did not include an estimate of the increased cost in its filing. Presumably it anticipated excluding the cost altogether from its filing or waiting until its compliance filing to incorporate this additional wheeling cost into rates. This rate increase is material enough, however, that it would have been reasonable for PacifiCorp

47 *Id.*

48 See Bonneville Power Administration, Docket BP-26-A-01, Administrator's Final Record of Decision, Appendix E, at PTP-26 (Jul. 24, 2025). The $2.043 per kilowatt per month rate compares to the former rate of $1.648 per kilowatt per month.

to identify the rate increase in its Direct Testimony and provide an estimate of the impacts.

Q. HAVE YOU ESTIMATED THE IMPACTS OF THIS CHANGE?

A. I recommend PacifiCorp provide an estimate of this impact in its Rebuttal Testimony. I roughly estimate that the new rates will result in a $20,000,000 increase to PacifiCorp's total-system costs, with approximately $1,579,413 allocated to Washington, which I reflected in my recommendation in Tabel 1, above. The PCORC revenue requirement impact of this change is a $1,649,018 increase after applying the production factor.

f. Nodal Pricing Model Fee

Q. WHAT AMOUNT OF COSTS HAS PACIFICORP FORECAST FOR THE NODAL PRICING MODEL FEES IN THE FORECAST PERIOD?

A. PacifiCorp forecast includes $[redacted] in nodal pricing model ("NPM") fees to the CAISO in the forecast period on a total-company basis.[49]

Q. WHAT IS THE NODAL PRICING MODEL?

A. The NPM was a term of art developed in the 2020 Protocol. Under the 2020 Protocol, PacifiCorp was expected to develop a pricing model that it would use to perform interjurisdictional allocation of NPC following the expiration of the Interim Period.[50] As amended, the 2020 Protocol Interim Period is set to expire on December 31, 2025.[51] As a part of implementing this requirement, the MSP Parties entered into an Memorandum of Understanding, provided in Appendix D of the 2020 Protocol, through which they agreed

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49 See Workpaper 250224-PAC-RJM-GNwWheeling-4-1-25(C), Tab "WheelingCosts," Excel Rows "160:161."

50 2020 Protocol at 39:828-830.

51 Docket No. UM 1050, Order No. 23-229 (June 30, 2023).

that PacifiCorp would procure a nodal pricing model from the CAISO, which it would present to the Framework issues group to begin developing a nodal pricing cost allocation method during the interim period.[52]

Q. DID PACIFICORP REPRESENT THAT THE NODAL PRICING MODEL WOULD BE USED TO DISPATCH ITS SYSTEM?

A. Yes. Prior to using the model for allocation purposes, the model was supposed to be used to perform system dispatch in lieu of existing dispatch modeling solutions. The 2020 protocol stated that PacifiCorp "will use best efforts to implement the NPM by the end of January 2021, for purposes of total-Company day-ahead scheduling."[53] In other words, PacifiCorp represented that it would be used for day-ahead scheduling. In testimony supporting the 2020 Protocol, PacifiCorp stated:

> When the NPM is developed and fully operational, the Company anticipates that it will be used at a total Company level for day-ahead schedules and commitment decisions, also referred to as day-ahead setup, and capture any co-optimized system efficiencies that the NPM creates.[54]

Q. DID PACIFICORP EXPECT THAT USING THE MODEL FOR DAY-AHEAD SCHEDULE AND COMMITMENT DECISIONS WOULD REDUCE COSTS?

A. Yes. PacifiCorp testified that the cost of the model would be offset by tangible NPC benefits through increased operational efficiencies and optimization:

> In addition to providing a method to allocate NPC among unique resource portfolios, the NPM potentially provides more granular day-ahead setup information resulting in potential operational cost savings. The potential operational cost savings will be the result of a more efficient day-ahead setup and the cost savings will be embedded in the actual NPC. These potential cost saving will be impossible to accurately and precisely track as

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52 2020 Protocol § 6.2.

53 *Id.*

54 *In re PacifiCorp General Rate Case*, Docket No. UE-191024, Exh. MGW-1CT-12-13-19 at 38:12-15 (December 13, 2019).

the calculation of such savings would rely on a counterfactual setup of the system without the NPM.[55]

In other words, it was expected that the model would be used in PacifiCorp's day-ahead set-up and that doing so would reduce its costs.

Q. HAS PACIFICORP BEEN USING THE MODEL TO DISPATCH ITS SYSTEM OR PERFORM DAY-AHEAD SCHEDULING?

A. No. PacifiCorp does not use the NPM to dispatch its system or to perform day-ahead scheduling.[56] It uses a model known as the PCI Energy Solutions' ("PCI") dispatch model to perform day-ahead dispatch and scheduling. While PacifiCorp has fully implemented the Nodal Pricing Model and the model is operational, it has never been used, other than cursorily, to perform day-ahead dispatch or scheduling. Nor has PacifiCorp modeled the cost reductions in its NPC forecasts. Thus, the NPM is not used and useful, and is providing no benefits to Washington customers.

Q. HOW DID PACIFICORP ASSERT THAT IT IS USING THE NODAL PRICING MODEL?

A. Allegedly, the only way it uses the NPM is in a process where it reviews and compares the NPM model output "to the PCI Energy Solutions'(PCI) dispatch model for discrepancies."[57] My understanding is, however, that the NPM outputs are not received in time to be adequately reflected in day-ahead dispatch decisions, and that any after-the-fact review process would only be cursory in nature. Further, I have seen no evidence

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55 *Id*, at 41:15-21.

56 Mullins, Exh. BGM-3 (PacifiCorp's Resp. to AWEC DR 38 in Oregon Docket No. UE 450).

57 *Id*.

that such a review and compare process actually occurs or that the day-ahead dispatch has ever been affected by such a process.

Q. HAS PACIFICORP USED THE NODAL PRICING MODEL TO DEVELOP A NET POWER COST ALLOCATION FRAMEWORK?

A. No. Apart from not being used in dispatch, as PacifiCorp asserted it would be, PacifiCorp never developed an allocation framework using the NPM. While there was some continued expectation that such a method would be developed, in July 2024, PacifiCorp terminated the Framework Issues Working Group that was responsible for developing the Post-Interim Period allocation framework using the nodal pricing model. Accordingly, there is no expectation that the NPM will be used as it was intended or contemplated under the 2020 Protocol, and given PacifiCorp's decision to join the EDAM, the efforts and costs incurred with respect to the NPM have been fruitless.

Q. DOES PACIFICORP PLAN TO EVER USE THE NODAL PRICING MODEL?

A. No. The nodal pricing model will not be used in the future, for allocation purposes, dispatch or otherwise. In response to AWEC Data Request 18, PacifiCorp stated:

> PacifiCorp does not intend on continuing to use and pay for the nodal pricing model (NPM) following joining the extended day-ahead market (EDAM).

Thus, PacifiCorp does not use the Nodal Pricing Model to perform system dispatch, it did not use the Nodal Pricing Model to develop an allocation framework and will not use the model going forward. Considering these factors, it is not reasonable for customers to continue paying for the model.

Q. DOES PACIFICORP HAVE THE ABILITY TO TERMINATE THE NODAL PRICING MODEL SERVICE FROM THE CAISO?

A. Yes. As **Mullins, Exh. BGM-6,** I have attached the NPM agreement between PacifiCorp and the CAISO, which contains the termination provision for the NPM payment. The NPM agreement "allows for termination by PacifiCorp for any reason, provided it has first entered into good-faith discussions for 30 days in an effort to resolve any differences."[58]

Accordingly, once it became apparent that the NPM was not going to be used to perform cost allocation, it should have been terminated, and in fact, it still can be. For purposes of the rate period in this case, PacifiCorp still can terminate the nodal pricing model service and cease paying all associated charges to the CAISO no later than January 1, 2026. This, at least, would be a prudent course of action, considering that the costs of the model are being reimbursed by ratepayers.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION.

A I recommend that all nodal pricing service charges be removed from the PCORC. PacifiCorp has stated that it will not be paying for such charges once it joins the EDAM in May 2026. The model will also not be used in the forecast period, nor will it provide any benefits to ratepayers. It can also be terminated on 30-days' notice. This recommendation produces an approximate $696,521 reduction to Washington-allocated NPC, with a $727,217 PCORC revenue requirement reduction after applying the production factor.

[58] Mullins, Exh. BGM-6 at 9.

g. CETA Adder

Q. WHAT ADJUSTMENT DID PACIFICORP PROPOSE WITH RESPECT TO CETA COMPLIANCE COSTS?

A. PacifiCorp proposed including a 50% adder on the cost of quarterly structured products allocated to Washington in order to model the cost of CETA compliance. PacifiCorp states that it applied a "premium of 50 percent on top of the costs of traditional quarterly power hedge blocks and applied that premium to all forward transactions in the NPC forecast."[59] PacifiCorp further explained that these additional costs did not assume that House Bill ("HB") 1329, which allowed for non-complaint, unspecified quarterly energy products to be included in customer rates, would pass.

Q. WHAT WAS THE IMPACT OF PACIFICORP'S MODELING CHANGE?

A. Based on its initial filing, the impact of this modeling change was a $18,237,237 increase to Washington-allocated NPC.

Q. DID HB 1329 PASS?

A. Yes. Pursuant to HB 1329, PacifiCorp is allowed to use unspecified structured products to serve its customers' loads in Washington. Accordingly, PacifiCorp's adjustment is no longer valid, and I recommend it be rejected. In response to Staff Data Request 63(b), PacifiCorp confirmed its position that, as a result of the bill's passage, the 50% adder should be eliminated.[60] After considering my recommendations above, this modeling approach results in a $14,729,676 reduction to Washington-Allocated NPC, a

[59] Mitchell, Exh. RJM-1CT at 18-20.

[60] Mullins, Exh. BGM-3 (PacifiCorp's Resp. to Staff DR 63(b), PacifiCorp states that as a result of the bill's passage the factor applied to structured product costs should be reduced from 1.5, *i.e.* a 50% adder, to 1.0, *i.e.* no adder).

$15,378,813 reduction to PCORC revenue requirement after applying the production factor.

h. Hypothetical Hedges

Q. WHAT MODELING CHANGE HAS PACIFICORP PROPOSED WITH RESPECT TO HEDGING COSTS?

A. PacifiCorp has proposed a major increase to Washington-allocated NPC to reflect modeled hedging costs.[61] PacifiCorp's testimony on this change is brief and not entirely clear, but explains that "additional short-term firm transactions are calculated, in quarterly 25 megawatt (MW) energy blocks of heavy or light load hour products, and loaded into the model to ensure that the quarterly average hedge ratio in the peak hour of each month satisfies the policy-dictated minimum requirements for the first quarter."[62] In other words, PacifiCorp includes hypothetical, future hedging contracts in its NPC forecast, even though those contracts have not yet been executed. In its description in testimony, PacifiCorp did not discuss the volumes nor pricing that it assumed, nor attempt to justify the reasonableness of the modeled impacts. It also did not discuss that a major part of the Washington adjustment was actually not a hedging cost at all, but rather, related to WRAP compliance, even though the WRAP will not be binding in 2026.[63]

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61 *See* Mitchell, Exh. RJM-1CT at 26:13-28:6.

62 *Id.*

63 Mullins, Exh. BGM-3 (PacifiCorp's Resp. to Staff DR 66).

Q. WHAT WAS THE IMPACT OF THIS CHANGE?

A. In Opening Testimony, PacifiCorp asserted that the impact of this change was $22.8 million.[64] From its workpapers, however, I was unable to isolate this amount. In the workpaper "250224-PAC-RJM-WANoHedgingRequirement-4-1-2025 (C)" PacifiCorp calculated a Washington-allocated NPC of $158,000,785 assuming all hypothetical hedging costs were eliminated from the modeling. Based on this, the true impact of the change appears to have been $36,585,109,[65] inclusive of the 50% CETA adder above. If the 50% adder is removed, the additional hedging costs decline to approximately $19,219,404. In other words, PacifiCorp's change to its hedging assumptions, which was accompanied by about two pages of vague testimony, increased costs by an amount that exceeds the entirety of the $10.6 million increase to NPC that PacifiCorp is proposing in this case, and about two-thirds of the overall revenue requirement change under consideration.

Q. HOW IS HEDGING EXPECTED TO IMPACT COSTS IN THE FORECAST PERIOD?

A. PacifiCorp explained in Docket UE-230482, its 2023 Power Cost Adjustment Mechanism filing, "[t]he purpose of hedging is to stabilize NPC, not to minimize NPC because hedges can raise or lower NPC depending on whether the fixed transaction prices are above or below prevailing spot market prices."[66] Thus, at this point, there is not

64 Mitchell, Exh. RJM-1CT at 29:4.
65 Relative to the filed $194,585,894 Washington-Allocated NPC.
66 Docket UE-230482, Staples Exh. DRS-1CT at 37:8-11.

sufficient information to conclude whether hedging will raise or lower NPC in the test period because the actual spot market prices for the test period are unknown.

Q. WHAT PRICE DOES PACIFICORP ASSUME FOR THE HYPOTHETICAL HEDGES?

A. The hedging prices for the hypothetical contracts are assumed at the rates specified in its Official Forward Price Curve ("OFPC"). In other words, PacifiCorp is not attempting to forecast a systematic hedging cost associated with its hedging program. It is simply assuming future hedges will be executed at the OFPC rate.

Q. WHAT SPOT MARKET PRICES ARE ASSUMED IN NPC FOR THE TEST PERIOD?

A. Monthly spot market prices assumed in NPC for the test period are also based on PacifiCorp's OFPC. Thus, in terms of hedging costs or benefits for the hypothetical contracts, there is none, because the monthly spot market prices and hedging prices are the same. In other words, the mark-to market value of the hedges is zero because the spot market and hedging price are equivalent.

Q. WHY THEN DOES THIS MODELING APPROACH RESULT IN INCREMENTAL HEDGING COSTS TO WASHINGTON?

A. The approximate $19,219,404 of additional cost is not actually due to a hedging benefit or cost. This is a cost associated with the model balancing around the fixed block of energy. Because the block of energy is a fixed amount, there are some hours when energy from the block must be sold into the market, and other hours when additional energy must be purchased to fill the same monthly requirements. It is this balancing activity that is resulting in the incremental costs, not the hedging itself. In addition to this, the modeled market cap assumptions appear to greatly influence the cost of this

modeling approach, particularly considering the further restrictions PacifiCorp has proposed in this case. Because PacifiCorp is adding in large volumes of purchases, the model has nowhere to sell the energy in hours where there is a surplus. Also, as a part of PacifiCorp's Day Ahead and Real Time ("DA/RT") adjustment, it increases the cost of hourly market purchases and reduces the revenue from hourly market purchases based on the historical relationship between its actual costs and monthly spot market rates, which magnifies the cost of this balancing activity. These blocks of power input into the model are also one of the factors contributing to the high levels of wind curtailments discuss above, as due to market cap limitations, there is often no place to dispose of the power when the block amount exceeds system requirements.

Q. ARE THE COSTS OF BALANCING AROUND STRUCTURED PRODUCTS ALREADY CAPTURED IN THE DA/RT ADJUSTMENT?

A. Yes. The purpose of the DA/RT adjustment is to capture the balancing costs associated with "[t]he products used to balance the Company's forward position in the wholesale market [that] are primarily available in flat 25 megawatt (MW), 16-hour or 8-hour blocks."[67] The DA/RT adjustment was specifically designed to "reflect the inefficiencies and associated costs of that operational practice of transacting on a monthly basis using, as an example, standard 25-MW increment, 16-hour block products…"[68] These products used to balance the Company's forward position in calculating the cost of system balancing in the DA/RT adjustment are the same "quarterly 25 megawatt (MW) energy

67 Mitchell, Exh. RJM-8 at 1:20-21.
68 *Id.* at 2:10-12.

blocks of heavy or light load hour products"[69] that PacifiCorp proposed to incorporate into NPC through its new hedging adjustment.

Q. WHAT VOLUME OF FORWARD TRANSACTIONS ARE INCORPORATED INTO THE DA/RT ADJUSTMENT

A. The monthly 25 MW blocks incorporated into the DA/RT adjustment can be found in the Total Company NPC Calculation tab "STF DA-RT"[70] A comparison between the monthly 25MW blocks included in DA/RT adjustment and those proposed in the new hedging adjustment are detailed in **Confidential Table 4,** below.

Confidential Table 4
25 MW Blocks in DA/RT vs. Hedging Adjustment –
Net Purchase MW

As can be seen, there are already a significant volume of 25 MW structured products embedded in NPC through the DA/RT adjustment. In fact, the two methods produce

69 *Id.* at 27:20-21.

70 See e.g. Workpaper 250224-PAC-RJM-TCNoHedgingRequirements-4-1-2025 (C), Tab STF RT Excel Rows 84:96.

comparable hedging volumes, at least for the HLH period. By including the structured product volumes through two separate adjustments—once through the DA/RT and also through the new hedging adjustment—PacifiCorp is overstating the cost of balancing around those 25MW blocks in the model.

Q. DOES PACIFICORP ALSO INCLUDE COSTS ASSOCIATED WITH THE WESTERN RESOURCE ADEQUACY PROGRAM IN ITS ADJUSTMENT?

A. Yes. While not clearly discussed in testimony, a major portion of the hedging requirements that PacifiCorp calculates is based on the requirements of the Western Resource Adequacy Program ("WRAP"). This calculation, for example, can be found in the workpaper "250224-PAC-RJM-GNPrehedgingPeak-4-1-25 (C)." The WRAP, however, is not yet binding, and will not be in a binding phase in 2026. Thus, WRAP related costs should not be considered in NPC in this case.

Q. DO YOU SUPPORT PACIFICORP'S HEDGING ADJUSTMENT?

A. No. Since the hedging prices are the same as the OFPC prices, future hedges are not expected to impose any additional cost on ratepayers relative to the OFPC PacifiCorp has used in this case. With respect to the balancing costs associated with 25 MW blocks, PacifiCorp's hedging adjustment is a valid replacement for at least that part of the DA/RT adjustment. While hedging itself is not expected to impose any additional costs, balancing around the structured products may. Notwithstanding, using both adjustments—the DA/RT and the hedging adjustment—in NPC overstates the cost of system balancing in relationship to 25 MW structured products. Since it would be difficult to remove the impact of those products from the DA/RT adjustment, my

recommendation is to eliminate the separate hedging adjustment PacifiCorp has proposed.

Q. WHAT IS THE IMPACT OF THIS RECOMMENDATION?

A. The impact of this recommendation is a $14,729,676 reduction to Washington-Allocated NPC, inclusive of the impact of the other adjustments that I have detailed above. After considering the production factor impacts, this results in a $15,378,813 reduction to PCORC revenue requirement.

i. Non-Precedential Modeling Changes

Q. WHAT DID PACIFICORP IDENTIFY AS NON-PRECEDENTIAL MODELING CHANGES?

A. PacifiCorp's direct testimony contains two sentences describing a class of adjustments that Witness Mitchell refers to as "Non-Precedential Modeling Improvements." Witness Mitchell does not actually go through the trouble of listing the adjustments, nor does the witness provide explanation of the adjustments in testimony. Rather, witness Mitchell provide a list of six different attachments, which contain testimony from other proceedings discussing these issues. In Mitchell, Exh. RJM-12, the impact of these non-precedential changes is detailed to be $7,750,901. PacifiCorp's Testimony on this matter is as follows:

> All non-precedential modeling improvements from the 2023 GRC are included in this filing. Please refer to Confidential Exhibit No. RJM-4C, Confidential Exhibit No. RJM-6C, Exhibit No. RJM-7, Exhibit No. RJM-8, Confidential Exhibit No. RJM-11C,32 and Exhibit No. RJM-12 for supporting testimony.[71]

[71] Exh. RJM-1CT at 35:14-17.

Q. WHAT DOES PACIFICORP MEAN BY "NON-PRECEDENTIAL MODELING" IMPROVEMENTS?

A. It's not clear. Usually, when something is cited as non-precedential it means that it is something that won't necessarily apply in future circumstances. It is possible that PacifiCorp cites these changes as non-precedential because they don't have a precedent from the Commission to use them. Review of Mitchell, Exhibit RJM-12 indicates that at least two of the changes are related to the changes to the DA/RT adjustment that PacifiCorp introduced in Rebuttal Testimony in the 2023 GRC, and which the Commission rejected.[72] The Commission stated:

> The Commission has reviewed PacifiCorp's limited evidence on the DA/RT adjustment, which was significantly updated in rebuttal testimony. However, we were unable to fully comprehend the means and methodology the Company used in calculating the rebuttal update …. [T]he workpapers provided to the parties showed different calculations than the workpapers provided earlier with initial testimony. We remain concerned that this update to the volume component [of the DA/RT adjustment] was only proposed in rebuttal, was insufficiently explained, and was not subject to appropriate vetting by the non-Company parties.[73]

Q. WHAT INFORMATION WAS PROVIDED IN THE ATTACHMENTS TO WITNESS MITCHELL'S TESTIMONY?

A. The attachments used to support those adjustments were the rebuttal testimony of Witness Mitchell and Witness Zacharia from the 2023 GRC, along with a whitepaper describing the mechanics of the DA/RT adjustment.

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72 2023 GRC, Order 08 ¶ 311.

73 *Id.*

Q. DID PACIFICORP SATISFY ITS BURDEN OF PROOF TO SUPPORT THESE MODELING CHANGES?

A. No. Attaching rebuttal testimony from a prior case that the Commission has already rejected as insufficient explanation as the sole means for justifying a change in forecasting method is not sufficient to satisfy PacifiCorp's burden of proof. The Commission stated that it was concerned that PacifiCorp had not adequately justified those changes in the 2023 GRC, and in this case PacifiCorp did not attempt to provide updated testimony but simply referred back to testimony from the prior proceeding. Attaching prior testimony as an exhibit in this case carries no greater evidentiary value than simply citing to it.

Q. IS PACIFICORP'S CHANGE TO THE DA/RT ADJUSTMENT VALID NOTWITHSTANDING THE EVIDENTIARY PROBLEMS?

A. No. PacifiCorp's change relates to the volume component of the DA/RT adjustment (the other component being a pricing component). Witness Mitchell testified in the 2023 GRC that "the DA/RT volume component adjusts system balancing transaction volumes to reflect the *inefficiencies* and associated *costs* incurred in actual operations. A calculation that is designed to simulate *costs* associated with real-world trading *inefficiencies* but produces substantial ($102 million) and unrealistic (artificial) arbitration *revenue* is producing an erroneous result."[74] In other words, PacifiCorp did not like that an outboard adjustment it created to increase NPC was now reducing NPC and decided to make an ad hoc modeling change in the spreadsheet to counteract this effect.

[74] Exh. RJM-8 at 2:17-23 (emphasis in original).

Moreover, Witness Mitchell's justifications for modifying the volume component of the DA/RT adjustment are entirely fictional. The volumes added in the DA/RT adjustment are added in by the Company, not due to some sort of optimization in the DA/RT adjustment. They are set at equal and offsetting levels. There is no buying at low prices and selling at high prices assumed in these volumes applied in the historical adjustment. Other than the impact of tying the DA/RT price impacts back to the historical values, the perfunctory offsetting volumes and their associated revenues are equal and offsetting, and therefore it is unclear how Witness Mitchell is concluding that this part of the historical adjustment is somehow engaging in arbitrage trading.

Q. DO YOU AGREE WITH THE CHANGES TO MARKET CAPS THAT PACIFICORP HAS PROPOSED AS A NON-PRECEDENTIAL ADJUSTMENT?

A. No. One of the other "non-precedential" modeling changes PacifiCorp proposed was to the treatment of market caps. PacifiCorp has historically not applied market caps on major Market Hubs, such as the Mid-Columbia and Palo Verde market. In its 2020 GRC, for example, PacifiCorp excluded market caps from the Mid-Columbia and Palo Verde market hubs, yet it subsequently changed that method, with no explanation, in the 2021 Power Cost Only Rate Case.[75] AWEC questioned this change in the 2023 GRC, but ultimately decided to withdraw the issue, because it did not substantially impact Washington-allocated NPC. I continue to support the use of the modeling approach that does not apply market caps to the major market hubs. Further, in this case PacifiCorp is proposing even further reductions to its ability to model transactions at those markets, by

[75] 2023 GRC, Mullins, Exh. BGM-1CT at 42.

excluding the sales of structured products from its historical averaging calculation. In order for Washington ratepayers to receive all the costs and benefits of resources allocated to them, it is important to let the model, not historical results, determine what volume of sales are economic. As new non-emitting resources are brought onto the system, it is expected that the volume of sales transactions will change over time. By rigidly limiting the model's ability to make sales in every hour based on historical averages, it dilutes the value that Washington is able to recognize from those non-emitting resources, and excluding structured products from the historical volume of sales used in the calculation only exacerbates this problem. Thus, in recommending the Commission reject PacifiCorp's "non-precedential" modeling changes, I also recommend the Commission reject its expansion of the market cap method to exclude structured products.

Q. WHAT IS THE IMPACT OF THIS RECOMMENDATION?

A. The impact of eliminating the non-precedential modeling changes, including removal of the new, more restrictive market cap method, is a $9,785,687 reduction to Washington allocated NPC, and a $10,216,942 reduction to PCORC revenue requirement after application of the production factor.

IV. INTERJURISDICTIONAL COST ALLOCATION

a. Generation Fixed Allocation Factors

Q. WHAT CHANGE IS PACIFICORP PROPOSING WITH RESPECT TO GENERATION ALLOCATION FACTORS?

A. For Washington, PacifiCorp is proposing to move away from dynamically calculated generation allocation factors to fixed allocation factors.[76] Thus, rather than being recalculated every year based on the relative loads and demands of the individual states, the generation allocation factors for Washington would be fixed for the life of the underlying resources.

Q. IS PACIFICORP PROPOSING TO FIX THE ALLOCATION FACTORS OF THE OTHER STATES?

A. No.[77] Notwithstanding, in the 2020 Protocol, one of the Resolved Issues for the Post-Interim Period allocation method was that all of the states, not just Washington, would transition to fixed allocation factors for generation resources.[78] Thus, while PacifiCorp is not proposing to use fixed allocation factors for the other states, it is possible, if not likely that the other states will choose to transition to fixed allocation factors, in which case there could be inconsistencies between the allocation factors used between the states. For example, it is possible that resources may be oversubscribed (i.e. more than 100% of the costs and benefits of a resource being allocated to the various states) or undersubscribed (i.e. less than 100% of the costs and benefits of a resource being allocated to the various states). As I mentioned above, this is a risk that PacifiCorp inherently has to bear due to

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76 Link, Exh. RTL-1T at 5:1-14.

77 *Id.* at 5:15-19.

78 2020 Protocol § 5.1.

its decision to seek a unilateral, rather than a negotiated solution to interjurisdictional allocation framework.

Q. DOES AWEC OPPOSE THE USE OF FIXED ALLOCATION FACTORS FOR GENERATION?

A. No. AWEC finds benefit in fixing the allocation factors for Washington. Given the growing loads in the West, fixing the allocation factors prevents Washington's investment in non-emitting resources from being diluted due to load growth in other states. The challenge with adopting fixed allocation factors, however, is devising methods that ensure all of the costs and benefits of the fixed resource shares are being allocated to Washington.

Q. WHY DOES A FIXED ALLOCATION PRESENT CHALLENGES WITH THE ALLOCATION OF THE COSTS AND BENEFITS OF RESOURCES?

A. Because PacifiCorp dispatches its resources as a system, there are often economic tradeoffs between resources. I discussed one of them above with respect to WEIM wind curtailments. PacifiCorp's modeling asserts (albeit inaccurately so) that it is necessary to reduce the output from non-emitting resources allocated to Washington, in favor of increasing output from coal resources, which are not allocated to Washington, to comply with certain coal supply agreement provisions. In this case, Washington ratepayers would be allocated a cost (i.e. the lost zero-cost output from the non-emitting resource and the associated PTCs), but the benefit of the associated curtailment actually inures to the other states that still rely on coal plants. These sorts of trade-offs are extremely complicated, and are one of the driving factors behind the complex structure of organized markets, such as the EDAM or Markets+.

Q. WHAT DO YOU RECOMMEND WITH RESPECT TO FIXED GENERATION FACTORS?

A. I recommend that the Commission accept fixed generation factors in this proceeding, but ensure in future proceedings where PacifiCorp's power costs are established that Washington customers receive the full value of the fixed share of resources they are paying for.

b. Chehalis Allocation

Q. WHAT IS PACIFICORP PROPOSING FOR CHEHALIS?

A. PacifiCorp is proposing to allocate 100% of the costs and benefits of the Chehalis power plant to Washington.[79] This change is relative to the 22.3% allocation that Washington ratepayers formerly received under the WIJAM. According to PacifiCorp, this change is necessary to "more closely match how it is planning to meet load in each of the states in which it operates."[80] In conjunction with this, PacifiCorp would remove Hermiston from Washington rates and reduce the allocation of the Jim Bridger 1 & 2 gas fired boilers from 22.3%, down to 7.9%.

Q. WHAT IS THE IMPACT OF PACIFICORP'S RECOMMENDATION FOR CHEHALIS?

A. Allocating 100% of Chehalis to Washington results in a $33,880,917 increase to fixed revenue requirement.[81] Notwithstanding, allocating Chehalis to Washington results in a $60,639,043 reduction to Washington-allocated NPC, using PacifiCorp's spreadsheet

79 Steward, Exh. JRS-1T.
80 Link, Exh. RTL-1T at 10:22-23.
81 Cheung, Exh. SLC-1T at 4, Table 2.

method. Thus, the Chehalis allocation results in an approximate $26,758,126 reduction to PCORC revenue requirement.

Q. WHY DOES PACIFICORP PROPOSE CHANGING THE ALLOCATION OF HERMISTON IN CONJUNCTION WITH THE CHANGE TO CHEHALIS?

A. PacifiCorp states "[r]emoving Hermiston from Washington rates at this time will facilitate PacifiCorp's compliance with CETA and ensure that there is not a significant overallocation of gas resource to Washington."[82] As a result of this change, the beneficial impact of allocating Chehalis to Washington is slightly offset by the impacts of removing Hermiston from Washington rates. Specifically, removing Hermiston resulted in a $4,426,900 reduction to fixed revenue requirement and a $6,774,607 increase to Washington allocated NPC.[83] The net effect of these two changes is a $2,347,707 increase to PCORC revenue requirement from the loss of Washington's share of Hermiston capacity. The benefits of allocating 100% of Chehalis to Washington, therefore, outweigh the additional cost from the removal of Hermiston.

Q. DOES AWEC SUPPORT THE PROPOSAL TO 100% OF ALLOCATE CHEHALIS TO WASHINGTON?

A. Yes. AWEC supports PacifiCorp's proposal to allocate 100% Chehalis to Washington as a means to mitigate the rate impacts of serving Washington customers and, because that plant is located in Washington, its principal use is in serving Washington customers, warranting its consideration as a Washington-allocated resource. To limit Washington's

82 Link, Exh. RTL-1T at 14:7-10.

83 Based on PacifiCorp's initial filing NPC.

increased exposure to gas plants, however, I also recommend that, like Hermiston, Jim Bridger Gas Units 1 & 2 be reallocated out of Washington rates.

c. Jim Bridger Gas 1 & 2 Allocation

Q. WHAT DOES PACIFICORP RECOMMEND FOR JIM BRIDGER GAS UNITS 1 & 2?

A. PacifiCorp proposes to reduce the allocation of Jim Bridger Gas Units 1 & 2 from 22.3%, down to 7.9%. PacifiCorp states that it is making this proposal to "to provide greater flexibility as it plans for compliance with the clean energy requirements set forth in CETA."[84] According to PacifiCorp, this proposal will "reduce the reliance on thermal generation to serve Washington customers and facilitate the eventual removal of these plants from Washington rates."[85]

Q. WHAT IS THE IMPACT OF THIS CHANGE?

A. Unlike Hermiston, where its removal from Washington rates increased costs, reducing the allocation of Jim Bridger Gas Units 1 & 2 to Washington is a net benefit to ratepayers. Reducing the allocation factor to 7.9% reduces fixed revenue requirement by $10,426,681; whereas NPC declined by just $1,812,867. Thus, there is an approximate $8,613,814 net benefit to Washington ratepayers for reducing the allocation of Jim Bridger Gas Units 1 & 2.

84 Link, Exh. RTL-1T at 14:2-3.

85 *Id.* at 14:4-6.

Q. DOES AWEC SUPPORT PACIFICORP'S RECOMMENDATION?

A. No. AWEC recommends that, in conjunction with Washington assuming a larger share of Chehalis, its allocation of Jim Bridger Gas Units 1 & 2 be reduced to zero. In other words, AWEC recommends that Jim Bridger Gas Units 1 & 2 be removed from rates.

Q. WHY DO YOU RECOMMEND REMOVING JIM BRIDGER UNITS 1 & 2 FROM WASHINGTON RATES?

A. Foremost, the Jim Bridger Gas Units 1 & 2 are thermally inefficient gas boilers, with emissions that are nearly double those of a combined cycle combustion turbine, such as Chehalis or Hermiston. As a result, the cost of power from those resources is very high. The continued operating costs of those plants do not exceed the NPC benefit being allocated to Washington rates, which is why reducing Washington's allocation results in a net benefit to ratepayers. In addition to this, Washington continues to be in a net-long energy position, even without the generation from Jim Bridger Units 1 & 2. Using my modeling methods above, for example, Washington is in a net long position of [redacted] MWh after removing the two units from Washington-allocated NPC.

Q. WHAT TYPE OF GENERATION TECHNOLOGY DO JIM BRIDGER GAS UNITS 1 & 2 RELY ON?

A. Unlike the highly efficient combined cycle combustion turbines at Chehalis, the Jim Bridger Gas Units 1 & 2 rely on steam turbines (the same ones that were used for coal operations) and gas-fired boilers. Apart from being economically costly to operate, gas boilers have very high emission factors that are comparable to, if not worse than, coal emissions. Chehalis is a highly efficient combined cycle combustion turbine, one of PacifiCorp's most efficient resources. It operates at heat rates of approximately

[redacted] btu/kWh.[86] The Jim Bridger Gas Units 1 and 2 boilers operate at heat rates of [redacted] btu/kWh, or nearly double that of Chehalis.[87] In other words, the emissions produced by a gas boiler, are nearly double that of a modern combined cycle. This means that the emissions of Jim Bridger Gas Units 1 and 2 are also nearly double those of a modern gas plant. Thus, their inclusion in Washington customer rates increases Washington's emission profile. Considering that Jim Bridger Units 1 & 2 actually increase costs to Washington ratepayers, their continued inclusion in Washington rates cannot be justified, whether in the context of the new allocation framework or otherwise.

Q. WHAT IS THE REMAINING PLANT BALANCE FOR JIM BRIDGER UNITS 1 AND 2?

A. As of December 31, 2025 the estimated plant balance is (-)$9,231,047, with (-)$2,045,875 allocated to Washington based on the existing allocation factors.[88] Thus, Washington has no stranded cost obligation with respect to the Jim Bridger Gas units.

Q. DID PACIFICORP PROPOSE REFUNDING THAT OVERPAYMENT WHEN IT REDUCED WASHINGTON'S SHARE OF JIM BRIDGER UNITS 1 AND 2?

A. No. By reducing the allocation factor, without addressing this overpayment by Washington customers, PacifiCorp is effectively keeping a portion of the overpayment for its shareholders. Regardless of what the Commission decides with Jim Bridger 1 & 2, these overpayments need to be addressed and refunded to customers prior to any reallocation. I recommend they be refunded to ratepayers over a 3-year period.

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86 See e.g. 250224-PAC-RJM-TCDirect 4-1-2025 (C), Tab "NPC", Cell "D810."

87 *Id. at* Cells "D826:D827."

88 Obtained from 250224-PAC-SLC-WP-JimBridgerGasPlantDetails-4-1-25 by summing the December 31, 2025 amounts on the tabs "JB 1&2 Existing (UE-230172)" and "JB 1&2 Pro Forma (UE-230172)."

Q. WHAT IS THE IMPACT OF THESE RECOMMENDATIONS?

A. Removing Jim Bridger Gas Units 1&2 from Washington customer rates in their entirety results in a $5,764,789 reduction to fixed revenue requirement relative to PacifiCorp's filed case (i.e. in addition to the $10,426,681 reduction reported in PacifiCorp's testimony). In addition to that amount, I recommend that a refund of $716,591[89] per year be returned to ratepayers, for a total fixed revenue requirement reduction of $6,481,380. Further, this change results in a $2,511,562 increase to Wasington-allocated NPC, or $2,622,247 after applying the production factor. Thus, the net effect of removing Jim Bridger Gas Units 1 and 2 in their entirety results in a $3,859,134 reduction to PCORC revenue requirement, along with improvements to Washington's emissions profile.

d. Rolling Hills Allocation

Q. WHAT DID PACIFICORP PROPOSE WITH RESPECT TO ROLLING HILLS?

A. PacifiCorp has proposed allocating the portion of the Rolling Hills wind plant that was disallowed from Oregon rates to Washington customers, resulting in an increase to the allocation from 7.9% to 34.9%.[90] This change increased fixed revenue requirement by $7,485,076, which was offset by a corresponding reduction of $3,236,394 to Washington Allocated NPC. Thus, the net impact of allocating Rolling Hills to Washington is a $4,248,682 increase in revenue requirement, at least based on PacifiCorp's filing.

89 Pre-tax revenue requirement value of $681,958 per year in amortization, including revenue sensitive costs.

90 Link, Exh. RTL-1T at 8:8-13.

Q. DO THE AURORA MODELED WIND CURTAILMENTS IMPACT THE VALUE OF THE ADDITIONAL SHARE OF ROLLING HILLS?

A. Yes. Rolling Hills had the second highest curtailment rate of any resource based on PacifiCorp's curtailment modeling approach that I contest above. If the must-run wind modeling I recommend is used, the NPC benefit of the additional Rolling Hills share increases to $5,062,570, meaning the net cost to Washington is $2,422,506 for assuming Oregon's disallowed share.

Q. DOES AWEC SUPPORT THE CHANGE TO THE ALLOCATION FACTOR FOR ROLLING HILLS?

A. Not if PacifiCorp is allowed to continue to curtail its wind resources. Since, under this modeling constraint, the additional Rolling Hills share results in a substantial increase to Washington revenue requirement, AWEC does not believe that it is reasonable for Washington to assume Oregon's disallowed share. However, if my recommendation above is accepted and PacifiCorp does not model wind curtailments, the net cost impact of reassigning a larger portion of Rolling Hills to Washington is materially reduced. Given the relatively small cost impact under this scenario combined with the additional CETA compliance benefits, AWEC would not oppose reassignment of Rolling Hills under this scenario.

e. System Overhead Factor

Q. WHAT CHANGE HAS PACIFICORP PROPOSED WITH RESPECT TO THE SYSTEM OVERHEAD FACTOR?

A. The System Overhead ("SO") factor is used to allocate a wide range of costs, such as administrative and general costs, which are not directly tied to generation output. Historically, the SO factor was calculated based on a percentage of allocated gross plant

balances.[91] PacifiCorp proposes to change the calculation of that factor to be calculated based on a weighting of three factors: System Capacity (SC), System Energy (SE) and System Gross Plant Distribution (SGDP). This change, according to PacifiCorp, will increase Washington allocated costs by $2,211,934.

Q. DOES AWEC SUPPORT CHANGING THE SO FACTOR IN THIS CASE?

A. No. This was intended to be a Power Cost Only Rate case, and the allocation of administrative and general costs falls outside of the scope of this proceeding, even as an offsetting factor.

Q. IS PACIFICORP PROPOSING TO FIX THE SO FACTOR, LIKE IT IS WITH WASHINGTON'S GENERATION FACTORS?

A. PacifiCorp is not proposing to fix the SO factor in this case. It will continue to be a dynamic factor calculated across the six-state service area, so there is no pressing need to revise that formula in this case. In contrast, reallocation of resources to accommodate the fixed factors is directly related to the power costs at issue in this case and appropriately considered in the overall PCORC rate impacts.

Q. IS THE NEW SO FACTOR CALCULATION REASONABLE?

A. No. The current SO factor allocates costs based on the relative gross plant of the various states. States with higher allocated gross plant balances are allocated more costs. In contrast, for the new factor, two-thirds of the costs are allocated as energy- and capacity-related costs, based on the System Energy ("SE") and System Capacity ("SC") factors. Of note, the SO factor is not used to allocate energy-related overhead costs, such as

[91] Cheung, Exh. SLC-1T at 7:13-8:2.

PacifiCorp's energy supply management office. Converting the SO factor into a predominantly energy and capacity-related factor is contrary to cost causation because those costs are not necessarily related to the energy and capacity requirements of individual states. The former method which relied on allocated gross plant balances of each state recognized that states with more fixed resources, including thermal generation units, require more administrative costs. Accordingly, apart from my recommendation for the Commission to not consider the SO factor change in this case, I recommend the Commission retain the current SO factor, if it does decide to consider the issue.

f. Industrial Curtailment Contracts

Q. WHAT COSTS HAS PACIFICORP ALLOCATED TO WASHINGTON IN CONNECTION WITH INTERRUPTIBLE CURTAILMENT CONTRACTS?

A. PacifiCorp allocates $2,271,196 in costs to Washington rates for two industrial contracts located in other states, one in Utah and the other in Idaho.

Q. WHAT DO YOU RECOMMEND FOR THESE CONTRACTS?

A. Washington did not approve the rates for those contracts, and given the move to fixed factors for Washington, there is no clear way to allocate the costs and benefits of those contracts to Washington rates. Accordingly, I recommend the costs of those industrial contracts be eliminated from Washington rates under the new allocation framework.

g. Washington Hedging Allocation

Q. DO YOU SUPPORT THE CHANGE TO A SEPARATE HEDGING BOOK FOR WASHINGTON?

A. As a general matter, AWEC does not believe it is necessary for the Commission to pre-approve of PacifiCorp's hedging policy in this case. The purpose of this case is to

establish just and reasonable rates considering the change in NPC resulting from the removal of coal fired resources from rates, along with other offsetting factors. In terms of PacifiCorp's hedging policy, it should bear the risk of developing a prudent policy for Washington ratepayers, without requiring pre-approval from the Commission. Further, AWEC does not believe that allocating explicit hedges to Washington customer rates is practical in the context of the spreadsheet method of NPC allocation that PacifiCorp has proposed. Specifically, while PacifiCorp would be directly assigning certain hedges to Washington under its proposal, it would also be assigning the cost of hedges executed for other states through the ordinary NPC allocation. While AWEC does not necessarily oppose some recognition of Washington-allocated hedges, AWEC believes that proposal is better evaluated in the context of a PCAM proceeding where the actual costs and benefits of PacifiCorp's hedging policies can be evaluated. At a minimum, AWEC believes the Commission should not place itself in the place of PacifiCorp management to pre-approve of a policy, which inherently needs to be evaluated in the context of PacifiCorp's day-to-day operations.

h. Decommissioning & Remediation Costs

Q. WHAT DOES PACIFICORP PROPOSE WITH RESPECT TO DECOMMISSIONING AND REMEDIATION COSTS?

A. As part of its 2026 Washington allocation methodology, PacifiCorp proposes that "Washington will continue to be allocated 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."[92]

Q. DO YOU RECOMMEND THE COMMISSION CONSIDER THE ALLOCATION OF DECOMMISSIONING COSTS IN THIS DOCKET?

A. No. I recommend that the allocation of decommissioning costs be considered in PacifiCorp's next general rate case. At this time, it is not known how the other states will handle Washington's former share of Bridger Units 3-4 and Colstrip Unit 4, and accordingly, it is not possible to develop any concrete findings about the reasonableness of Washington's ongoing contribution to decommissioning and remediation costs for those plants.

Q. IS PACIFICORP'S TREATMENT OF COAL PLANT DECOMMISSIONING COSTS REASONABLE UNDER ITS WASHINGTON 2026 ALLOCATION METHOD?

A. Likely not. Without the benefit of a full evidentiary record on coal plant decommissioning costs in this docket, it is difficult to make a final recommendation on this issue; however, allocating ongoing decommissioning costs to Washington for plants the state no longer receives benefits from seems unreasonable on its face. A more reasonable approach would be to allocate decommissioning costs to Washington based on the ratio of the plants' total useful lives to the period of time Washington benefitted from these plants. All else equal, Washington rates will increase as a consequence of the removal of coal from rates at the end of this year; it is unreasonable to require customers also to pay for decommissioning costs incurred after these plants are removed. AWEC

[92] Link, Exh. RTL-2 § 10.

reserves the right to modify this recommendation in a later proceeding with the benefit of a fuller record on this issue, if it is not resolved in this case.

Q. IF PACIFICORP IS PROPOSING TO CONTINUE THE SAME TREATMENT OF COAL PLANT DECOMMISSIONING COSTS UNDER THE WIJAM, AND AWEC SUPPORTED THE WIJAM, WHY DOES AWEC NOW OPPOSE THIS TREATMENT?

A. AWEC supported the WIJAM as part of a comprehensive settlement of issues in PacifiCorp's 2020 general rate case, UE-191024. AWEC was agreeable to the treatment of coal plant decommissioning costs in the WIJAM because of the other benefits the WIJAM provided and because it knew the WIJAM would expire before PacifiCorp would be required to remove coal from rates. At this point, parties would be able to make new recommendations with regard to how decommissioning costs are allocated to Washington customers. Consistent with this understanding, the 2020 rate case settlement provided that the parties "reserve all rights to challenge future decommissioning costs estimates in subsequent general rate cases or other proceedings in which such cots are at issue."[93]

Q. DO YOU ALSO RECOMMEND PACIFICORP COMMIT TO AN ANNUAL FILING TO BEGIN TRACKING THE AMOUNT OF DECOMMISSIONING COSTS ALLOCATED TO WASHINGTON CUSTOMERS?

A. Yes. I recommend that PacifiCorp be required to report annually to the Commission the amount of decommissioning funds collected from Washington customer rates along with the total balance available for decommissioning. Such a filing will provide transparency

[93] Docket No. UE-191024, Order 09, Appen. B ¶ 26 (Dec. 14, 2020).

to ensure that the amounts paid by Washington customers are actually used to cover decommissioning and remediation costs.

V. OTHER ISSUES

a. Production Tax Credit Rate

Q. WHAT PTC RATE HAS PACIFICORP ASSUMED IN THE PCORC REVENUE REQUIREMENT?

A. As PacifiCorp explained in response to AWEC Data Request 17, PacifiCorp assumed a 3.0 ¢/kWh PTC rate for all PTC-eligible wind in this proceeding.[94]

Q. HAS PACIFICORP REVISED ITS FORECAST?

A. Yes. In response to AWEC Data Request 17, PacifiCorp also noted that it had made an error in its calculation of the PTCs rate for new wind resources constructed after December 31, 2021.[95] PacifiCorp noted that it would make this change in its Rebuttal Testimony.

Q. DO YOU AGREE WITH PACIFICORP'S 3.0 CENTS/KWH PTC RATE FORECAST?

A. No. Based on information available today, the base PTC rate will increase to 3.1 ¢/kWh. for tax year 2026.

Q. HOW HAVE YOU MADE THAT CONCLUSION?

A. The PTC rate is established pursuant to Internal Revenue Code ("IRC") § 45.[96] The PTC rate was first authorized in 1993 and established at a baseline of 1.5¢/kWh. To account for inflation, the IRS adjusts the PTC rate each year by applying an "inflation adjustment

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94 Mullins, Exh. BGM-3 (PacifiCorp's Resp. to AWEC DR 34).

95 *Id.*

96 26 U.S.C. § 45(b)(2) (2021).

factor." The PTC rate changes based on increases in an economic indicator called the "GDP implicit price deflator" published by the department of commerce. The inflation adjustment factor is calculated for a tax year by taking the GDP implicit price deflator for the prior year and dividing by the GDP implicit price deflator for calendar year 1992. The resulting inflation adjustment factor is then multiplied by the 1.5¢/kWh rate to derive the inflation adjusted PTC, rounded to the nearest tenth of a cent.

Q. WHAT WAS THE INFLATION ADJUSTMENT FACTOR FOR 2025?

A. The 2025 inflation adjustment factor was published by the IRS in the Federal Register on May 27, 2025, and resulted in an inflation adjustment factor of 1.9971. This factor was calculated by taking the 2024 (i.e. the year prior to 2025) implicit price deflator of 125.23 and dividing by the 1992 implicit price deflator of 62.707. The resulting inflation adjustment factor yielded a 3.0¢/kWh PTC rate for 2025, which is the same rate that PacifiCorp has used in this case. In other words, PacifiCorp is forecasting that there will not be an increase to the PTC rate in 2026.

Q. WILL THE PTC RATE INCREASE IN 2026?

A. Barring unexpected high levels of deflation in the third and fourth quarters of 2025, yes. The inflation adjustment factor for the 2026 PTC rate will use the implicit price deflator for calendar year 2025 as its basis. The Department of Commerce will not publish the annual GDP implicit price deflator for calendar year 2025 until the spring of 2026 Notwithstanding the Department of Commerce also publishes quarterly GDP implicit price deflator indices, and based on those quarterly increases in the GDP implicit price deflator that have occurred to date, it can be determined that, even if the GDP implicit

price deflator remains flat for the remainder of the year, an increase to the PTC rate will be triggered for 2026. In other words, the quarterly GDP implicit price deflator has already exceeded the threshold necessary to trigger an increase in 2026. This is detailed in **Table 5** below.

Table 5
2026 PTC Rate Forecast

2025 PTC Rate Calculation	
1993 PTC	1.5
1992 GDPIPD	62.707
2024 GDPIPD	125.23
Infl. Adj. Factor	1.9971
2025 PTC	**3.0**

2026 PTC Rate Forecast	
1993 PTC	1.5
1992 GDPIPD	62.707
2025.Q1	127.429
2025.Q2	128.059
2025.Q3 (Est)	*128.059*
2025.Q2 (Est)	*128.059*
2025 GDPIPD	127.902
Infl. Adj. Factor	2.0397
2026 PTC	**3.1**

In **Table 5** I present the 2025 and 2026 PTC rate calculation side by side. For the 2025 calculation the 2024 Gross Domestic Product Implicit Price Deflator is a known value. For the 2026 calculation, the 2025 Gross Domestic Product Implicit Price Deflator is not known. Using the average of the quarterly data received to date and assuming no further inflation for the remainder of the 2025, however, it can be shown that the PTC rate will increase to 3.1 ¢/kWh in 2026, barring significant deflation.

Q. IS THE CALCULATION DIFFERENT FOR RESOURCES CONSTRUCTED AFTER 2021?

A. Yes. There is a slightly different formula applicable to wind resources constructed after 2021, although the two formulas typically track each other closely. In addition, there is a 10% bonus applied for wind constructed after 2021 that meets certain domestic content requirements. For those projects, I propose using the 31 ¢/kWh rate PacifiCorp identified in response to AWEC Data Request 17.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. Updating the PTC rate, consistent with the above forecast, produces a $1,126,917 reduction to PCORC revenue requirement.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.