BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 450

In the Matter of	)
	)
PACIFICORP	)
	)
2026 Transition Adjustment Mechanism.	)
	)

OPENING TESTIMONY OF BRADLEY G. MULLINS

ON BEHALF OF THE

ALLIANCE OF WESTERN ENERGY CONSUMERS

(REDACTED)

June 17, 2025

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AWEC/101 - Qualification Statement of Bradley G. Mullins

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Confidential AWEC/103 - Historical Congestion Revenue Analysis

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Bradley G. Mullins. I am the Principal Consultant of MW Analytics, a consulting firm that represents utility customers before state public utility commissions in the Northwest and Intermountain West. My witness qualifications have been attached as **Exhibit AWEC/101**.

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

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

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I discuss my initial review of PacifiCorp's proposed 2026 Net Power Cost ("NPC") forecast. Specifically, I evaluate PacifiCorp's $2,420,428,436 forecast of NPC for calendar year 2026 (the "Forecast Period"),[1] as well as other adjustments that impact recovery through Schedule 125 rate.

Q. WHAT WAS THE SCOPE OF YOUR REVIEW?

A. I did not review every modeling method or technique PacifiCorp proposed or included in its filing. My review was limited to an evaluation of significant issues surrounding modeled wind production, wheeling expenses, Western Energy Imbalance Market ("WEIM") congestion revenues, and policy surrounding the Hunter and Huntington Power Plants.

[1] PAC/101, Mitchell/1:36.

Q. PLEASE SUMMARIZE YOUR PRINCIPAL RECOMMENDATIONS AND CONCLUSIONS.

A. **Confidential Table 1**, below, provides an estimate of my recommended adjustments to 2025 NPC, which results in a $63,739,419 reduction to Oregon-allocated NPC. Brief descriptions of my recommendations follow the table.

Confidential Table 1
Recommended TAM Adjustments – Whole Dollars

- *Wind Feathering:* I recommend eliminating a wind feathering method PacifiCorp has implemented in Aurora because it produces uneconomic dispatch and is inconsistent with actual wind operations.

- *P50 Production Factors:* I also recommend modeling wind capacity factors based on the production factors assumed at the time those resources were built, also referred to as the P50 production factors.

- *Erroneous PPA Dispatch:* Similar to wind, I recommend modeling Power Purchase Agreements ("PPAs") as non-dispatchable, in contrast to PacifiCorp's modeling, which erroneously treats PPAs as dispatchable resources.

- *BPA Real Power Losses:* I recommend removing Bonneville Power Administration ("BPA") real power losses from wheeling expense because those losses are already reflected in PacifiCorp's load forecast and because PacifiCorp did not develop its forecast based on forward market prices.

- *Nodal Pricing Model:* I recommend removing the cost of the Nodal Pricing model from NPC because PacifiCorp stated that it will no longer purchase that service from the CAISO, and PacifiCorp has not been using the nodal pricing model for dispatch or allocation, except cursorily so.

- *WEIM Congestion Revenues:* I recommend that WEIM congestion revenues be modeled distinctly in the calculation of WEIM benefits and in the calculation of extended day-ahead market ("EDAM") benefits because those revenues are not captured in the historical benefits calculation.

- *Hunter and Huntington:* With the expiration of the 2020 Protocol, I recommend the Commission initiate a proceeding to reevaluate the exit dates for the Hunter and Huntington power plants.

II. WIND CAPACITY FACTORS

Q. WHAT ISSUE HAVE YOU IDENTIFIED WITH RESPECT TO PACIFICORP'S WIND CAPACITY FACTORS?

A. The first three issues in my testimony—wind feathering, P50 production factors, and erroneous PPA dispatch—all relate to PacifiCorp's wind capacity factors, and my recommended changes to correct severe modeling problems with the way that wind is being considered in PacifiCorp's forecast. Foremost, PacifiCorp has attempted to model a dispatch action known as wind feathering, in which the Aurora model is allowed to curtail wind output relative to the production values entered into the model. The way the method has been implemented, however, produces an erroneous dispatch outcome, resulting in extreme volumes of curtailed wind and wind curtailments that are uneconomic. Wind curtailments from feathering are supposed to reduce costs, yet PacifiCorp's method is resulting in significantly higher modeled costs, contrary to the purpose of wind feathering. PacifiCorp's forecast of wind production from its wind fleet can be found in the workpaper "Aurora GN Wind and Solar CONF." In that workpaper, PacifiCorp employs a method where it uses historical data to estimate the wind

production factors of certain wind facilities. In addition to correction for the erroneous feathering method, I also have concerns with using the historical data to forecast wind production factors and recommend the long-term engineering studies (also known as the P50 estimates) be used as the basis for wind output included in the forecast. Finally, as I have attempted to correct the faulty modeling surrounding wind feathering, it became apparent that PacifiCorp has implemented Aurora in a way that allows for the economic dispatch of non-dispatchable PPAs, without considering liquidated damages under those contracts. It is likely that this behavior has to do with deeper issues within the Aurora model dispatch solution, although, for purposes of this testimony, I have attempted to correct it by treating both owned wind resources and PPAs as must run resources.

Q. PLEASE DESCRIBE THE MAJOR WIND INVESTMENTS THAT PACIFICORP HAS UNDERTAKEN IN RECENT YEARS.

A. Over the past ten years, PacifiCorp has engaged in major investment in its wind fleet, including both the construction of several thousand megawatts of new wind and the repowering of its existing fleet. For example, Energy Vision 2020 ("EV 2020") was a major initiative undertaken by PacifiCorp consisting of 1,150 MW of new wind resources, among other resources, located in Wyoming. Part of the justification for this project was the availability of production tax credits ("PTCs"), which were at the time set to expire. Also around the same time as it undertook EV 2020, PacifiCorp undertook a major effort to repower the majority of its existing wind fleet. Repowering was described in detail in Docket No. UE 352, and was a strategy undertaken by PacifiCorp whereby it rebuilt its existing wind fleet in order to improve the wind production factors and to be able to obtain additional production tax credits.[2] In

[2] Docket No. UE 352, Order No. 19-304 at 1 (Sep. 16, 2019) ("In this order, we adopt a stipulation of all parties and authorize PacifiCorp…to recover, effective October 1, 2019, and December 1, 2019, the revenue requirements corresponding with anticipated in-service dates for repowered wind facilities."); *id.* at Appendix A, at 3 ("The Stipulating Parties agree that PacifiCorp's decision to repower the nine wind facilities described in PacifiCorp's

addition to these initiatives, there have been a series of other new wind resource additions, such as Pryor Mountain Wind, Rock River, Foot Creek, Rock Creek I and Rock Creek II, some of which have only recently been put into service or are still under construction.

Q. DID PACIFICORP PERFORM ENGINEERING STUDIES TO ASSESS THE LONG-TERM WIND POTENTIAL FROM THESE INVESTMENTS WHEN IT PROPOSED THEM?

A. Yes. At the time these facilities were proposed and presented for Commission approval, PacifiCorp conducted due diligence of the sites and production levels that would be achieved from these investments. The long-term engineering wind production estimates that PacifiCorp prepared at the time the facilities were planned are known as the "P50" production estimates. P50 refers to the fact that there is a 50% probability that wind production will be higher than the projected values and 50% that it will be lower. Absent the adequate production from these wind investments, there may not have been an economic case for the projects. The type of engineering analysis that PacifiCorp undertook to develop the P50 production estimates for these investments, for example, was described in Docket No. UE 352:

> PacifiCorp worked with its consultant, Black & Veatch (B&V), to use the extensive data history from PacifiCorp's facilities to derive precise estimates of the energy production expected from repowering. This analysis used millions of data points from the operational record of the wind facilities and incorporated additional modeled wake losses anticipated from the new equipment. Wake losses are the reduction in generation at turbines downwind of other turbines due to reduced wind speed and increased turbulence in the airflow—or wake—behind a turbine.[3]

Q. HOW DO THE P50 PRODUCTION ESTIMATES COMPARE TO THE WIND PRODUCTION ESTIMATES PROPOSED IN THIS CASE?

A. The variance between the P50 production estimates and the 2026 TAM forecast are detailed in **Confidential Table 2**, below.

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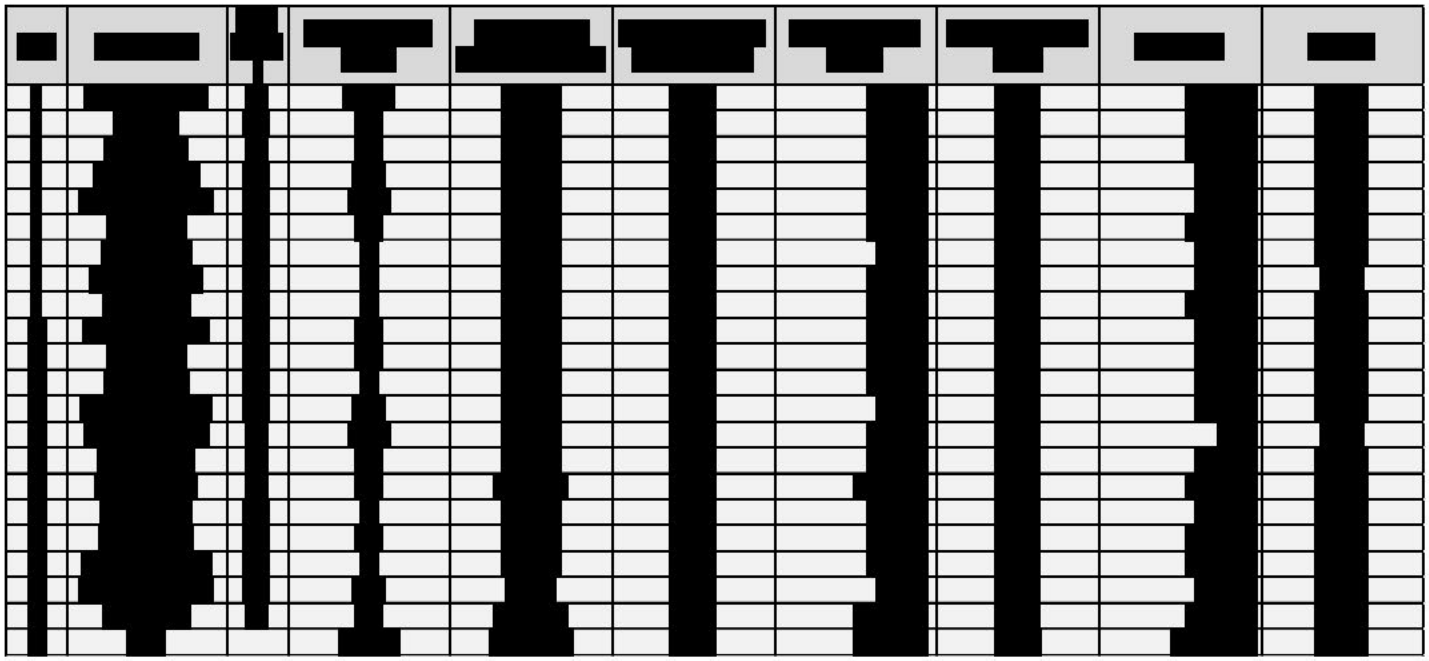
initial filing was prudent and in the public interest, based on the analysis and projections of ratepayer benefits provided by PacifiCorp, including the Company's qualification for production tax credits (PTCs).").

[3] Docket No. UE 352 PAC/200, Hemstreet/13:12-18.

Confidential Table 2
2026 TAM vs P50 Wind Production Estimates



As can be seen from the figure, the wind production included in the TAM is approximately [redacted] lower than the amount projected in the forecasts that were used to justify the resources. In the context of repowering, the TAM production factors are, for most resources, lower than the actual capacity factors prior to repowering. Given that these production factors also serve as the basis for the PTCs included in the TAM revenue requirement, this magnitude of a variance is highly concerning and highly impactful.

Q. WHAT IS DRIVING THESE VARIANCES?

A. There appear to be two sources for these major variances, although as I discuss below, the second one is somewhat murky. First, PacifiCorp has transitioned to a method of using a 4-year average of historical wind production for repowered wind resources as an input into the Aurora model. For non-repowered wind that has been in service for less than four years, PacifiCorp is continuing to use values that are close to the P50 forecast. This resulted in lower

production factors being entered into the Aurora model because the recent history of wind production for repowering resources was lower than P50 estimates.

Q. WHAT IS THE SECOND SOURCE OF THE TABLE 2 VARIANCES?

A. I had thought the variances were due solely to the use of average historical production for repowered resources. As I demonstrate below, however, the cause of most of the variance was actually due to an error in the way wind is being modeled in Aurora. On closer review, it became apparent that that the production forecast input into Aurora for most wind resources was based on, or at least close to, the P50 production estimates. Even for those resources that relied on a historical average, the Aurora model output was much lower than the forecast production input into the model. This gets to the second, and more impactful cause of the Table 2 variances, the Aurora model itself appears to be producing wind output values that are different than the wind production values being input into the model. Aurora is erroneously treating wind resources as dispatchable, resulting in modeled wind production that is significantly lower than both the historical 4-year data and the P50 production estimates. **Confidential Table 3**, below, shows the: 1) the P50 production factors; 2) the production factors input into Aurora; and 3) the production factors output from Aurora.

Confidential Table 3
Wind Production Factors Input Into, and Exported Out of, Aurora

As can be seen the use of historical wind production versus the P50 forecast represented only a minor portion of the variance in wind production observed in **Table 2**. The values input into Aurora, which relied in part on historical data, were only [redacted] lower than the P50 production estimates. The majority of the variance—[redacted]—is based on differences between the production estimates input into Aurora and those output from the Aurora model. Thus, it is the Aurora model algorithm itself that is reducing the output from wind facilities relative to the forecast values that are input into the model.

Q. WHY WOULD AURORA PRODUCE LOWER WIND PRODUCTION THAN INPUT INTO THE MODEL?

A. Ordinarily, wind is modeled as a "Must-Run" resource, meaning the production forecast is input as static values, which the model is not allowed to dispatch, up or down. It appears, however, that PacifiCorp has incorporated into the Aurora model a technique that allows for the "feathering" dispatch of wind resources. In the Resources Table within Aurora, PacifiCorp

assigned a negative dispatch price to wind at a rate equal to the grossed-up PTC, and provided the model with the option to curtail wind output based on that negative price.

Q. WHAT IS WIND FEATHERING?

A. Wind feathering is an action taken by a utility where it prevents a wind turbine from spinning even though the wind is blowing. This might be done, for example, in circumstances when prices are negative and it is more beneficial for a utility to not receive generation output from a wind resource, even though the wind is blowing. In such a circumstance, a utility can avoid selling into the market at negative energy prices, or alternatively purchase more power at negative energy prices, in both cases reducing overall NPC. Given that PacifiCorp receives PTCs from its wind plants, however, feathering also results in an opportunity cost equal to the lost value of those credits. Thus, in order for it to be economical for PacifiCorp to feather its owned wind plants, the price must be sufficiently negative to justify the lost PTCs. Given the high cost, particularly for those wind plants with PTCs, feathering is typically a dispatch action undertaken as a last resort.

Q. HOW DID THE NEGATIVE DISPATCH PRICE PACIFICORP IMPLEMENTED FOR WIND IN AURORA IMPACT NPC?

A. Inputting negative dispatch prices to incorporate feathering into Aurora did not result in economic savings, nor was that there sufficient economic savings to justify lost PTCs. To investigate the impact of PacifiCorp's modeling method, I performed an Aurora model scenario which eliminated the feathering dispatch option and required Aurora to treat wind as must-run resources. Based on that study, I was able to demonstrate that PacifiCorp's method for implementing feathering wind dispatch actually resulted in an approximate $[redacted] million increase to total Company NPC. In other words, the feathering dispatch was uneconomic, and therefore, erroneous. Further, it also resulted in the loss of approximately

$[redacted] in PTCs. Thus, in total, the feathering dispatch produced $[redacted] of additional system costs, which demonstrates that the method PacifiCorp is using is erroneous.

Q. HOW DO YOU RECOMMEND HANDLING WIND PRODUCTION IN THIS CASE?

A. First, rather than relying on historical production, I recommend the P50 engineering studies that served as the basis for the Commission's prudence determination be used to develop the wind production assumed in Aurora. The historical wind production over a four year period does not represent the long-term wind potential from PacifiCorp's wind fleet. In addition, PacifiCorp has not performed any new long-term engineering wind production studies to inform its forecast. Finally, if PacifiCorp makes a decision to commit billions of ratepayers dollars based on long-term production estimates of wind production, it is expected that those estimates will be reliable, and if they are not, that is a reason to question the reasonableness of these projects.

Second, I recommend removing the wind feathering modeling technique from Aurora. This technique is producing results that are erroneous and may be indicative of even deeper problems with the Aurora model dispatch solution. While the correct negative dispatch prices were input into the model, the model itself was not able to produce an economic dispatch solution using those negative prices. It is possible, for instance, that there are many other errors in the model like this, caused by similarly erroneous dispatch modeling, although given the timeline for testimony, I have been unable to perform a detailed review of all possible errors.

Q. WERE THERE ANY OTHER ERRONEOUS DISPATCH OR OTHER PROBLEMS YOU ENCOUNTERED?

A. Yes. When I attempted to model wind resources as must-run resources, and not subject to the erroneous feathering dispatch modeling, I noticed that the Aurora model began dispatching

PPAs in a similar manner. This was also an erroneous outcome because I am not aware of any PacifiCorp PPAs that are dispatchable, and to the extent that they are, it is my understanding that PacifiCorp would likely be required to pay liquidated damages to the counterparty. I have attempted to correct this issue by forcing all PPA's to be must-run resources in the model, not subject to dispatch. This produced a higher NPC because the model was dispatching the PPAs without considering the associated liquidated damages from refusing to take delivery from a contracted supply. It is not clear to me why the model was doing this, and as I mentioned, there are likely a deeper problems with the model that is causing this result, which I will continue to investigate over the course of this proceeding.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATIONS ON WIND PRODUCTION?

A. As set forth in **Confidential Table 1**, I have detailed my recommendations related to wind production in three parts: 1) correcting the erroneous wind feathering method; 2) using the P50 capacity factors; and 3) correcting the erroneous dispatch of PPAs. In total, making the above modeling corrections results in a $[redacted] reduction to Oregon-allocated TAM revenues, consisting of $[redacted] in reduced Oregon-allocated NPC and $[redacted] in increase Oregon-allocated PTCs.

III. 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.[4] In BP-24, BPA implemented more stringent

[4] This change continued in BPA's BP-26 rate case proceeding, with no proposed changes to the treatment for real power losses. As such, AWEC does not anticipate that BPA's current treatment will change when BP-26 rates are set in late July.

requirements surrounding the way that power losses were required to be settled, requiring physical losses to be settled concurrently.[5] 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. Based on this change, PacifiCorp also added a new wheeling charge into its NPC forecast of $[redacted]. 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.

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 as real power losses.[6] 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.

[5] BP-24-E-BPA-09 at 5:4-10.
[6] Bonneville Power Administration, Open Access Transmission Tariff, Schedule 11, at 137 (June 30, 2024).

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 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 deliver 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 AWEC Data Request 16, 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.

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 MWh's 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 retails sales based various statistical

analyses, and then grosses-up those values using a loss factor. In AWEC Data Request 34, 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 lines losses are added to test period retail sales by jurisdiction to produce jurisdictional load, it is then transformed to hourly loads.

Q. WHAT LINE LOSS FACTORS DOES PACIFICORP USE?

A. In AWEC Data Request 35, PacifiCorp was requested to provide workpapers supporting the line loss calculations included in its load forecast. In response, PacifiCorp provided an excel workbook that contained only the hardcoded line loss factors applied for each of its jurisdictions, and did not provide the requested workpapers. In response to a follow-up, in AWEC Data Request 60, PacifiCorp explained that the hard-coded numbers were calculated based on actual losses measured over the period 2019 through 2023:

> The line loss factors are calculated as the average of the most recent five years (2019 through 2023) of the annual load at generation over retail sales. (Load/Retail -1). The average losses are then rounded to four decimal places.

This was confirmed through an evaluation of the line loss workpapers that were provided in response to AWEC Data Request 59.

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. 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 59, no adjustment was applied to reflect the transition to financial loss settlement through BPA. Accordingly, the load forecast 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 16, PacifiCorp stated "financial loss settling is lower cost than returning losses physically." 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. 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 Oregon.

Q. HAVE YOU ALSO IDENTIFIED CALCULATION ERRORS IN PACIFICORP'S FORECAST OF BPA REAL POWER LOSSES?

A. Yes. While not impactful on my recommendation, it is also necessary to point out that PacifiCorp's forecast used a backwards-looking calculation of real power losses, rather than a forecast based on expected market prices. PacifiCorp used historical data in its calculation, and did not adjust that calculation based on changes to expected market prices in the forecast period. Notably, PacifiCorp used actual historical real power loss settlements over the period August 2023 through July 2024 to perform its adjustment, and since PacifiCorp did not have a

full set of annual data to perform its analysis, relied on estimates of what the loss calculation would be months prior to March 2024. Namely in August 2023 through February 2024, before it transitioned to financial loss settlement, PacifiCorp estimated its losses using historical WEIM prices. Because the historical settlements and calculations relied on historical market prices, however, it resulted in a skewed and inaccurate calculation of real power losses. This can be seen in **Confidential Table 4**, below.

Confidential Table 4
BPA Financial Losses Repriced Based on OFPC

As can be seen from the table, if the financial losses are repriced based on actual forward prices in the forecast period, the result is a smaller cost for losses.

IV. 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.[7]

Q. WHAT IS THE NODAL PRICING MODEL?

A. The 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.[8] As amended, the 2020 Protocol Interim Period is set to expire on December 31, 2025.[9] As a part of implementing this requirement, the Muti-State Process ("MSP") Parties entered into an Memorandum of Understanding, provided in Appendix D of the 2020 Protocol, through which the agreed 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.[10]

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 leu 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." In other words, PacifiCorp represented

7 5-BD Workpaper GNw_Wheeling CONF, Tab "WheelingCosts," Excel Rows "160:161."
8 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol at 39:828-830 ("2020 Protocol").
9 Docket No. UM 1050, Order No. 23-229 (June 30, 2023).
10 2020 Protocol at 6.2.

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.[11]

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

A. Yes. In addition, it was expected that the cost of the model would be offset by tangible NPC benefits through increased operational efficiencies and optimization. PacifiCorp stated:

> 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 the calculation of such savings would rely on a counterfactual setup of the system without the NPM.[12]

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. As PacifiCorp explained in response to AWEC Data Request 38, PacifiCorp does not use the nodal pricing model to dispatch its system or to perform day-ahead scheduling. 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.

[11] UM 1050, PAC/300, Wilding/7:20-23 (Dec. 2019).
[12] *Id.* at 11:4-10.

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

A. Allegedly, the only way it uses the nodal pricing model is in a process where it reviews and compares the NPM model output "to the PCI Energy Solutions'(PCI) dispatch model for discrepancies."[13] My understanding is, however, that the nodal pricing model 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 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 nodal pricing model. 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.[14] Accordingly, there is no expectation that the NPC 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 20, PacifiCorp stated:

[13] AWEC/102 (PacifiCorp response to AWEC Data Request 38).
[14] Docket No. UM 1050, PacifiCorp's Notice of Termination of the Framework Issues Workgroup Under the 2020 Protocol (July 11, 2024).

> 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. In response to AWEC Data Request 38(b), PacifiCorp stated the following

> Per section D of the NPM Agreement, "the 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".

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 Forecast Period in this case, PacifiCorp 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, could 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 TAM forecast period. PacifiCorp has stated that it will not be paying for such charges once it joins the EDAM in May 2026.[15] 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

[15] PAC/100 Mitchell/22:15-17.

produces a [redacted] reduction to total-company NPC, with approximately [redacted] allocated to Oregon.

V. WEIM CONGESTION REVENUES

Q. PLEASE SUMMARIZE THE ISSUE YOU HAVE IDENTIFIED RELATED TO CONGESTION REVENUES.

A. In Docket No. UE 434, I raised an issue regarding the consideration of congestion revenues, and other similar uplift charges, in the WEIM benefits forecast reflected in NPC. I continue to support that adjustment in this case.

Q. WHAT WEIM BENEFITS DOES PACIFICORP INCLUDE IN NPC?

A. In its initial filing, PacifiCorp calculated WEIM benefits of $[redacted] on a total-Company basis,[16] with $32,156,369 allocated to Oregon.[17]

Q. HOW DID PACIFICORP CALCULATE THIS AMOUNT?

A. This amount was calculated based on a regression between historical monthly market prices and a calculation of historical WEIM benefits. This approach was discussed in the Direct Testimony of Vijay Singh.

Q. HOW WERE THE HISTORICAL WEIM BENEFIT AMOUNTS CALCULATED IN THAT ANALYSIS?

A. PacifiCorp has been unable to produce any workpapers supporting the calculation of historical WEIM benefits. In response to AWEC Data Request 42, PacifiCorp was requested to provide the workpapers supporting the historical WEIM benefits calculations. In response, PacifiCorp provided the historical WEIM benefit amounts but was unable to produce any workpapers showing the derivation of the amounts. In response to AWEC's Data Request 42(d), wherein

[16] *See* workpaper "_OR UE-450 ORTAM26-Mitchell Direct Apr 2025 CONF" Tab "EDAM and EIM," Cell "P2."
[17] Using the 26.884% System Generation ("SG") factor.

AWEC requested the deliverables from the consultant who prepares the calculations, PacifiCorp objected and stated:

> PacifiCorp uses a third-party vendor, Yes Energy, to calculate WEIM benefits. […] WEIM benefit files produced by Yes Energy benefits are aggregated for determining monthly WEIM benefits. The monthly WEIM benefits are then used in PacifiCorp's WEIM benefit forecasting models.[18]

Thus, PacifiCorp was not able to provide any analytical support for the historically calculated WEIM benefits, other than the level of monthly WEIM benefits that Yes Energy calculated.

Q. DID PACIFICORP PROVIDE ANY OTHER INFORMATION TO DETERMINE HOW THE CALCULATIONS WERE PERFORMED?

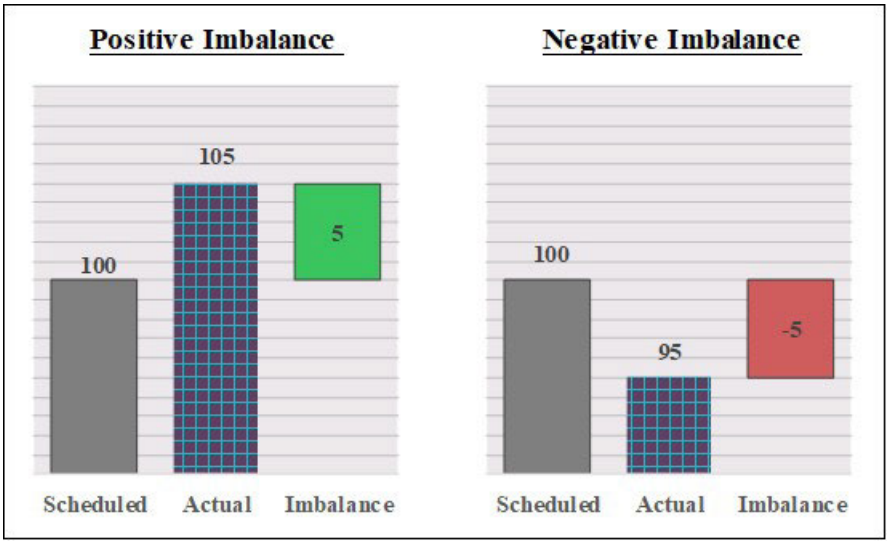
A. In response to sub part (c) of its response to AWEC Data Request 42, PacifiCorp also provided a link to a document that explained the method used by the CAISO to calculate historical WEIM benefits.[19] PacifiCorp asserted that the WEIM transfers benefits developed by Yes Energy followed this general methodology, although this is not necessarily evident from the information it provided. The method detailed in the linked document was a very high-level calculation, which relied on the assumed volume WEIM inter-regional transfers and valued those based on the difference between a calculated generation cost and the regional load aggregation point price. Notwithstanding it being a high-level calculation, however, the method is principally an estimate of instructed imbalance revenues from the market. In particular because the benefits are settled on a single LAP, it does not consider the benefit of congestion revenue allocations, which are a major benefit of the market that cannot be modeled in a historical benefits calculation of this sort.

[18] AWEC/102 (PacifiCorp's Response to AWEC Data Request 42).
[19] *See EIM Quarterly Benefit Report Methodology*, *available at:* https://www.westerneim.com/Documents/EIM-BenefitMethodology.pdf.

Q. WHAT IS AN IMBALANCE?

A. An imbalance represents the difference between the volume of load or generation scheduled (*i.e.*, planned or forecast) and the actual volume. The concept of an imbalance is described graphically in **Figure 1**, below:

Figure 1
Illustration of Positive and Negative Imbalances from Energy Source (MWh)



Prior to an operating period, typically an hour, a wholesale transmission customer must submit a forecast to its transmission service provider detailing expected sources and uses of electricity in the operating period, including expected generation from network resources and expected loads based on its load forecast. These forecasts are generally referred to as a "schedule." To the extent that the actual sources or uses of electricity vary from the scheduled amount, the transmission customer will have an energy imbalance. As a balancing area authority, a transmission service provider is responsible for maintaining the voltage and frequency of its transmission system. A balancing area authority is responsible for dispatching resources in real-time to serve imbalances of transmission customers. Correspondingly, transmission customers must reimburse the transmission service provider for the imbalance energy provided by, or be reimbursed for imbalance energy supplied back to, the balancing

area. In other words, an energy imbalance can be either positive or negative, resulting in cases where sometimes the market participant must pay for shortfall imbalance energy and other times when it is paid for excess imbalance energy. The charges for these energy imbalance services are detailed in the transmission service provider's open access transmission tariff. Historically, these energy imbalance services were settled using a percentage of monthly market index prices, but that changed with the initiation of the WEIM.

Q. HOW DOES THE WEIM CREATE A MARKET FOR IMBALANCE SERVICES?

A. The WEIM provides an organized market for imbalance services that is settled in 15 minute and, subsequently, 5-minute intervals over the course of an hour. Before the WEIM, each transmission system operator in the West managed imbalances independently. The WEIM started trading nearly ten years ago in November 2014 between PacifiCorp and the CAISO as a then novel framework to jointly dispatch in real-time to serve imbalances in the most economical way possible across the two systems. It has since expanded rapidly through the fragmented balancing authority areas in the Western Interconnection, with most now participating in the market framework. In the WEIM, real-time dispatch is managed and optimized collectively over the entire WEIM footprint, as opposed to each balancing area going it alone. The market uses a computer model operated by the CAISO that optimizes dispatch in real-time and then settles imbalance energy based sub-hourly LMPs calculated in the same model. As a part of the market, dispatchable generators are re-dispatched relative to their scheduled output and used to serve imbalance energy of non-dispatchable resources and loads across the entire WEIM footprint, with the objective of doing so in the most economical way possible. Dispatchable generators are then compensated for responding to the instructions.

Q. WHAT ARE INSTRUCTED AND UNINSTRUCTED IMBALANCES?

A. In the hour-ahead, all market participants must submit schedules that balance their individualized system, meaning that all scheduled generation and scheduled load must be equal. The CAISO market model, however, reoptimizes the sub-hourly dispatch for the entire WEIM footprint, subject to the actual operating costs and capabilities of dispatchable resources, as well as transfer limitations and other security constraints between participants. Over the course of an hour, the market model will provide automated generation instructions for dispatchable resources to dispatch up or dispatch down, relative to the scheduled output to serve the footprint more efficiently. These instructions are referred to as an "Instructed Imbalance." In contrast, an "Uninstructed Imbalance" occurs when the actual energy from a non-dispatchable resource or a load is different from the forecasted schedule.

Q. HOW DO UTILITIES BENEFIT FROM RESPONDING TO MARKET INSTRUCTIONS?

A. The WEIM settlement revenues from an instructed imbalance represent the gross proceeds from the WEIM, and do not include the cost of fuel incurred to generate those proceeds. The net benefit of an instructed imbalance, therefore, is the margin between the gross settlement proceeds and the incremental fuel costs from responding to the WEIM dispatch instructions. Importantly, dispatch instructions may be up or down. A high-cost dispatchable resource could also be instructed to back down production. In this case, the utility saves on fuel costs but is also required to reimburse the cost of WEIM energy that it consumed instead of generating. In this case the net benefit, is the difference between the fuel cost savings and the settlement payment made to the WEIM**.**

Q. DO INSTRUCTED IMBALANCES CONSIDER CONGESTION REVENUES?

A. No. Instructed imbalances exclude the financial benefit of congestion revenues. Accordingly, for the purpose of comparing to the Aurora model output, it is appropriate to consider the benefit of these congestion revenues PacifiCorp's forecast.

Q. WHY DO CONGESTION REVENUES ARISE?

A. Generally speaking, congestion revenues arise because the sum of the energy imbalance settlements paid and those received do not sum to zero, most commonly resulting in excess revenues for the market. Congestion revenues are designed to reallocate the excess revenues, or costs, earned in by the market using a cost-causative allocation method.

Q. WHY DO THE INSTRUCTED AND UNINSTRUCTED ENERGY IMBALANCE SETTLEMENTS NOT SUM TO ZERO?

A. As stated, LMPs have three different components: congestion, losses, and energy. Accordingly, LMPs are different at each point or node in the system. If they were not, one can devise a simplistic example, where the WEIM is settled on a single price for all instructed and uninstructed imbalances. In such a case, the charges assessed for purchasing imbalance energy and the revenues paid for supplying it would be the same. It would result in zero net revenues for the overall market. That simplistic example, however, is not how the market operates. The market is specifically designed to assess higher prices where demand for energy imbalance services is higher, and lower where it is not. This is a fundamental part of the economic optimization of the WEIM footprint. Because of the effects of congestion and losses, there are unique prices throughout the system and the charges assessed for purchasing imbalance energy will tend to be at higher prices than for supplying it, resulting in net revenues to the overall market footprint. This intuitively makes sense, because the points where energy imbalances are being purchased generally have higher demand, and correspondingly, higher prices. The

CAISO, however, does not keep the net revenues resulting from the differential pricing for itself. It allocates the revenues to participants using the neutrality settlement charges identified above, one for each component of the LMP.

Q. HAS PACIFICORP ACKNOWLEDGED THAT CONGESTION REVENUES ARE APPROPRIATE TO CONSIDER OUTSIDE OF ITS POWER COST SIMULATION?

A. Yes. In AWEC Data Request 45, PacifiCorp acknowledged the following quote from the EDAM study conducted by the Brattle Group:

> "EDAM Congestion and Transfer Revenues: are collected by the EDAM market administrator (CAISO) and allocated back to market members as specified in the EDAM design. In the market, generators are paid the price at their location, which is accounted for in the [Adjusted Power Costs (APC)] calculation as revenue from market sales. Similarly, load pays the price at its location, also accounted for in the APC metric as the cost of purchased power. However, due to congestion on the system when trading between member BAAs, the locational price paid by load in most instances is higher than the locational price paid to generators. Therefore, on EDAM transactions between member BAAs, the money collected from load is typically greater than the money paid out to generators. The EDAM design mandates that this additional money be allocated back to member BAAs. The same process is in place today in the WEIM, and WEIM members currently receive allocations of congestion revenues collected in the market."

Congestion revenues are present in both the EDAM and in the WEIM, and must be considered in the benefits calculations for both market terms. For purposes of the EDAM, congestion revenues were not considered in the power cost simulations Brattle performed and needed to be added separately outside of the model as an additional benefit of the market participation. The same is true for the WEIM congestion revenues. These revenues represent one of the most significant benefits from WEIM market participation, particularly as the number of participants have increased, and excluding them, results in an inaccurate calculation of WEIM benefits. Accordingly, considering those benefits in the NPC forecast in this case is appropriate.

Q. ARE CONGESTION REVENUES REFLECTED IN THE YES ENERGY BENEFITS STUDIES?

A. No. The documentation and the summary level workpapers provided make no mention of the treatment of congestion revenues. Further, the imbalance valuation used by the Yes Energy study is performed at a single LAP for each WEIM participant, and accordingly, does not consider the transmission constraints leading to congestion revenues. Congestion revenues are based on the revenues and receipts across the entire market footprint, and absent a comprehensive analysis of every node within the WEIM, it would be impossible to adequately capture the full value of congestion revenues, which are allocated to PacifiCorp.

Q. WHAT DO YOU RECOMMEND?

A. I recommend an adjustment to incorporate congestion settlements into PacifiCorp's WEIM benefits calculation using a multiple regression against Mid-Columbia and Palo Verde market prices. This calculation is detailed in **Confidential Exhibit AWEC/103**. As can be seen over the 4-years 2021 through 2024, PacifiCorp has recognized $[redacted] in congestion revenues. Using the results of a multiple regression applied against that data, I calculate an approximate $[redacted] total-Company forecast of congestion revenues for the forecast period, which I recommend be considered in PacifiCorp's NPC forecast as an addition to WEIM benefits. The use of multiple regression produces results that are only slightly higher than the $[redacted] four-year average of congestion revenues. On an Oregon-allocated basis, my recommended adjustment produces a $[redacted] reduction to TAM revenues.

VI. HUNTER AND HUNTINGTON FUEL SUPPLY

Q. WHAT ARE YOUR RECOMMENDATIONS FOR HUNTER AND HUNTINGTON?

A. I recommend the Commission comprehensively evaluate Oregon's participation in PacifiCorp's coal fleet considering the termination of the 2020 Protocol. This could occur in PacifiCorp's forthcoming allocation proposal docket, or as a stand-alone proceeding.

Q. WHY ARE THE UNCONTROLLED FUEL COSTS FOR THE HUNTER AND HUNTINGTON PLANT CONCERNING?

A. While many events and challenges have occurred with respect to the fuel supply at the Hunter and Huntington plants, PacifiCorp's response to those challenges has largely been ad hoc, without considering the continued economics of those plants from Oregon customer's perspective. Oregon law HB 1547 (2016) requires PacifiCorp to remove coal from Oregon rates by the end of 2029,[20] and considering that requirement, its decisions regarding the fuel supply and the long-term benefit of those plants from Oregon's perspective deserves greater due diligence, rather than the continual renegotiation of the fuel supply contracts on terms that are increasingly worse and worse for ratepayers. There needed to be comprehensive analyses conducted that considers not only the fuel supply, but also the potential for retiring and replacing those resources. None of that has occurred and efforts to determine Oregon's participation in these resources has been considered a *fait accompli,* as a matter that was resolved and only considerable within the context of PacifiCorp's multi-state allocation process. Accordingly, in the TAMs and IRPs, most of PacifiCorp's analysis has been from the point of view that anything PacifiCorp pays for fuel at Hunter and Huntington is a sunk cost, and therefore, has no bearing on the continued operation of those resources. While in the 2020 Protocol parties agreed to Oregon exit dates for those resources, that does not mean that

[20] ORS 757.518.

PacifiCorp should not continue evaluating the plants from Oregon's perspective and considering Oregon's policies.

Q. DO YOU HAVE CONERNS ABOUT THE HUNTER AND HUNTINGTON COAL SUPPLY AGREEMENTS IMPACTING 2026 OREGON NPC?

A. Yes. The Commission was clear in the 2024 TAM that it expected PacifiCorp to meaningfully evaluate the Hunter and Huntington February 15, 2024 Coal Supply Agreement ("CSA") amendments so that the prudence for forecast NPC could be determined in future power cost proceedings.[21] As noted above, my concern is that PacifiCorp's analysis has focused on fueling Hunter and Huntington as system resources through December 31, 2029. This has led PacifiCorp to agree to minimum take amounts that may not be appropriate or aligned with Oregon's ratepayers' economic interests.

Q. WHAT DID THE 2020 PROTOCOL SAY ABOUT OREGON EXIT DATES?

A. The exit dates provision of the 2020 Protocol can be found in section 4, Implemented Issues. That section described items that were "implemented and effective during the Interim Period."[22] Thus, the provisions of that section had no bearing on the post-interim period allocation method, nor any other potential method that PacifiCorp might unilaterally propose following the termination of the agreement. The general condition the 2020 Protocol Signatories agreed to for an exit order was a four-year notice to other states.[23] In the document, it was agreed that Oregon's exit dates for Hunter and Huntington would be December 31, 2029.[24]

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21 Docket No. UE 434, Order 24-309 at 3-4 (Sep.19, 2024).
22 2020 Protocol § 4.
23 *Id.* at § 4.1.2.
24 *Id.* at § 4.1.3.3.

Q. DO THOSE EXIT PROVISIONS SURVIVE FOLLOWING THE TERMINATION OF THE AGREEMENT?

A. No. As amended, the Interim Period under the 2020 protocol will expire on December 31, 2025. No subsequent agreement has been reached with respect to a post-interim period allocation method. As noted above with respect to the NPC, PacifiCorp terminated negotiations in order to unilaterally propose a new allocation method, which I understand to be forthcoming. Absent an agreement amongst the states, however, my understanding is the implemented issues in the 2020 Protocol, including the Exit Notification requirements will no longer apply after the end of this year, unless otherwise agreed by the Commission in the subsequent allocation method.

Q. IS IT REASONABLE FOR THE COMMISSION TO REEVALUATE EXIT DATES?

A. Yes. As evidenced from the fuel supply issues experienced at Hunter and Huntington, much has occurred since the 2020 Protocol was negotiated, and reevaluation of Oregon's exit dates is appropriate. Considering that no agreement was reached and that PacifiCorp terminated negotiations amongst the states, the four-year notification period for an exit order need no longer apply.

Q. SHOULD THE RESULT OF AN APPROVED ALLOCATION METHODOLOGY BE REFLECTED IN 2026 NPC?

A. Potentially. It is unclear what the timing will be for the Commission to evaluate and approve an allocation methodology once PacifiCorp files its proposal. However, and in particular given that PacifiCorp controls the timing of its filing, the Commission should put PacifiCorp on notice that an approved allocation methodology with a 2026 implementation date may be used to allocate actual NPC costs as part of PacifiCorp's 2026 PCAM proceeding, and that such adjustments may occur outside of the PCAM's deadbands and sharing bands if determined appropriate.

Q. DOES THIS CONCLUDE YOUR OPENING TESTIMONY?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 450

In the Matter of	)
	)
PACIFICORP	)
	)
2025 Transition Adjustment Mechanism.	)
	)

EXHIBIT AWEC/101

QUALIFICATION STATEMENT OF

BRADLEY G. MULLINS

MW Analytics
ENERGY & UTILITIES

Bradley Mullins
Principal Consultant
brmullins@mwanalytics.com

MW Analytics is the professional practice of Bradley Mullins, a consultant and expert witness that represents utility customers in regulatory proceedings before state utility commissions throughout the western United States. Mr. Mullins started MW Analytics in 2013 and, since then, has sponsored expert witness testimony in over 100 regulatory proceedings on a variety of subject matters, including revenue requirements, regulatory accounting, pricing, cost allocation, depreciation and new resource additions. MW Analytics also assists utility customers with informal regulatory, legislative energy policy matters, as well as providing advisory and other energy consulting services.

Education

- Master of Accounting, Tax Emphasis, University of Utah, 2007
- Bachelor of Finance, University of Utah, 2006
- Bachelor of Accounting, University of Utah, 2006

Prior Relevant Experience

PacifiCorp, Portland, Oregon: Net Power Cost Consultant 2010 – 2013

- Analyst responsible for power cost modeling and forecasting
- Supported regulatory filings, including drafting prewritten testimony, preparing annual power cost deferral filings, and developing qualifying facility avoided cost calculations

Deloitte, San Jose, California: Tax Senior 2007 – 2009

- Staff accountant responsible for preparing corporate tax returns for multinational corporate clients and partnership tax returns for hedge fund clients
- Joined national tax practice specialized in research and development tax credits

Recent Expert Witness Testimony

Docket	Party	Topics
In re Application of Nevada Power Company d/b/a NV Energy for Establishment of a Wildfire Self Insurance Policy and Cost Recovery for the Wildfire Self-Insurance Policy, PUC Nv. Docket No. 25-01018 (Cons.)	Smart Energy Alliance, et. al.	Revenue Requirement, Rate Spread, & Rate Design
In re Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision, Or. PUC Docket No UG 520	Alliance of Western Energy Consumers	Net Power Costs
In re Avista Corporation, d/b/a Avista Utilities, Request for a General rate Revision, Or. PUC Docket No. UG 519	Alliance of Western Energy Consumers	Revenue Requirement, Rate Spread, & Rate Design
In Re the Application of Rocky Mountain Power for Authority to Increase Its Retail Electric Service Rates by Approximately $123.5 Million per Year or 14.7 Percent, to Establish an Insurance Cost Adjustment Rider, to Revise the Energy Cost Adjustment Mechanism, to Approve the Wildfire Mitigation Plan, and to Approve a Voluntary Renewable Energy Credit Program, Wy.PSC Docket No 20000-671-ER-24 (Record No 17659)	Wyoming Industrial Energy Consumers	Net Power Costs
In re Cascade Natural Gas Corporation, 2024 General Rate Case, Wa.UTC Docket No. UE-240008	Alliance of Western Energy Consumers	Revenue Requirement
In re the Application of Rocky Mountain Power to Increase Current Rates by $84.3 Million to Recover Deferred Net Power Costs Under Tariff Schedule 95 Energy Cost Adjustment Mechanism and to Increase Current Rates By $2.1	Wyoming Industrial Energy Consumers	Power Cost Deferral

Docket	Party	Topics
Million Under Tariff Schedule 93, REC and SO2 Revenue Adjustment Mechanism, Wy.PSC Docket No 20000-664-EM-24 (Record No 17547)		
In re Puget Sound Energy, 2024 General Rate Case, Wa.UTC Docket No. UE-240004 (Cons.)	Alliance of Western Energy Consumers	Revenue Requirement
In re Portland General Electric Company, Requests for a General Rate Revision, Or.PUC Docket No UE 343	Alliance of Western Energy Consumers	Revenue Requirement
In re Avista 2024 General Rate Case, Wa.UTC Docket No. UE-240006 (Cons.)	Alliance of Western Energy Consumers	Revenue Requirement
In re Portland General Electric Company, 2025 Annual Update Tariff, Or.PUC Docket No UE 346	Alliance of Western Energy Consumers	Power Cost Forecasting
In re PacifiCorp 2025 Transition Adjustment Mechanism, Or.PUC Docket No. UE 434	Alliance of Western Energy Consumers	Power Cost Forecasting
In re the Application of Sierra Pacific Power Company d/b/a NV Energy for authority to adjust its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto, PUC Nv. Docket No. 24-02026	Smart Energy Alliance	Revenue Requirement
In re Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for Approval of the Cost Recovery for the 2023 Natural Disaster Protection Plan Regulatory Asset Account, PUC Nv. Docket No. 24-03006	Smart Energy Alliance and Wynn Las Vegas, LLC	Wildfire Mitigation
In re the Petition of PacifiCorp d/b/a Pacific Power & Light Company, 2022 Power Cost Adjustment Mechanism Annual Report., Wa.UTC Docket UE-230482.	Alliance of Western Energy Consumers	Power Cost Deferral
In re Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision, Or.PUC Docket no. UG 490	Alliance of Western Energy Consumers	Revenue Requirement
Application of Nevada Power Company d/b/a NV Energy for authority to adjust its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto, PUC Nv. Docket No. 23-06007; *Application of Nevada Power Company d/b/a NV Energy for approval of new and revised depreciation and amortization rates for its electric and common accounts,* PUC Nv. 23-06008.	Circus Circus Las Vegas, LLC, HR Nevada, LLC, and Smart Energy Alliance	Revenue Requirement, Depreciation
In re the Application of Rocky Mountain Power To Increase Current Rates By $50.3 Million To Recover Deferred Net Power Costs Pursuant to Tariff Schedule 95 Energy Cost Adjustment Mechanism And To Decrease Current Rates By $1.5 Million Pursuant to Tariff Schedule 93, REC and SO2 Revenue Adjustment Mechanism, Wy.PSC Docket No. 20000-642-EM23	Wyoming Industrial Energy Consumers	Power Cost Deferral
In re the Application of Rocky Mountain Power for Authority to Increase Its Retail Electric Service Rates by Approximately $140.2 Million Per Year or 21.6 Percent and to Revise the Energy Cost Adjustment Mechanism, Wy.PSC Docket No. 20000-633-ER-23	Wyoming Industrial Energy Consumers	Power Costs
In re of Avista Corporation, d.b.a. Avista Utilities, Request for a General Rate Revision, Or.PUC Docket No. UG 461	Alliance of Western Energy Consumers	Revenue Requirement
In re Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for Approval of the Cost Recovery of the Regulatory Assets Relating to the Development and Implementation of their Joint Natural Disaster Protection Plan., PUC Nv. Docket No. 23-03004	Smart Energy Alliance and Wynn Las Vegas, LLC	Wildfire Mitigation

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 450

In the Matter of	)
	)
PACIFICORP	)
	)
2026 Transition Adjustment Mechanism.	)
	)

EXHIBIT AWEC/102

PACIFICORP RESPONSES TO DATA REQUESTS

AWEC Data Request 016

Reference work paper "GNw_Wheeling CONF", Tab "Known and Measurable" Rows "20:30": Please provide a description of the BPA loss return charges and explain what changed historically to require those charges to be assessed.

Response to AWEC Data Request 016

Referencing the Company's responses to TAM Support Set 2 (5-business day work papers) supporting the direct testimony of Company witness, Ramon J. Mitchell, specifically confidential folder "All_DataSeriesFiles CONF", confidential file "GNw_Wheeling CONF", the Company responds as follows:

Please refer to Attachment "_UE 450_NONC_PACtoAWEC_IR016R_Attach_05022025" which provides a copy of Bonneville Power Administration's (BPA) Transmission Services Open Access Transmission Tariff (OATT) effective June 30, 2024.

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.

AWEC Data Request 020

Reference work paper "GNw_Wheeling CONF": Does PacifiCorp intend on continuing to use and pay for the Nodal Pricing Model following joining of the EDAM?

Response to AWEC Data Request 020

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

AWEC Data Request 034

Please explain how line losses are considered in the development of PacifiCorp's load forecast.

Response to AWEC Data Request 034

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

AWEC Data Request 035

Please provide all line loss factors, and associated work papers, as used in the load forecast in this proceeding.

Response to AWEC Data Request 035

Please refer to Attachment "_UE 450_NONC_PACtoAWEC_IR035R_Attach_05192025" which provides the loss factors and the associated work papers used in the load forecast in this proceeding.

Line Lossses by Jurisdiction

Oregon	9.93%
Washington	10.57%
California	10.42%
Utah	4.15%
Idaho	5.29%
Wyoming PPL	9.12%
Wyoming UPL	3.26%

AWEC Data Request 038

Reference PacifiCorp's response to AWEC Data Request 20:

(a) Is PacifiCorp currently using the Nodal Pricing Model? If yes, please explain how the model is currently being used.

(b) Does PacifiCorp have the ability to cancel the Nodal Pricing Model services from the CAISO? If yes, please discuss the cancellation or termination terms under the contract.

(c) Please provide a copy of the contract between PacifiCorp and the CAISO for the nodal pricing model and associated services.

Response to AWEC Data Request 038

(a) Yes. Generation bids, load bids and ancillary service bids are submitted into the nodal pricing model (NPM). Non-binding generation awards, along with nodal prices, are published daily by the California Independent System Operator (CAISO). Generation awards are reviewed and compared to the PCI Energy Solutions'(PCI) dispatch model for discrepancies

(b) Yes. Per section D of the NPM Agreement, "the 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".

(c) Please refer to Attachment "_UE 450_NONC_PACtoAWEC_IR038R_Attach_05192025" which provides a copy of the NPM Agreement dated December 20, 2019, and the first amendment to the NPM agreement dated October 24, 2023, between the California Independent System Operator (CAISO) and PacifiCorp.

December 20, 2019

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: California Independent System Operator Corporation
Filing of CAISO Rate Schedule No. 6052

Docket No. ER20-____-000

Dear Secretary Bose:

The California Independent System Operator Corporation (CAISO) submits for filing and acceptance the Nodal Pricing Model Agreement dated December 20, 2019, between the CAISO and PacifiCorp (Agreement).[1] The Agreement sets forth the terms under which the CAISO will modify its existing day-ahead optimization systems to provide a nodal pricing model solution for PacifiCorp. This solution will produce separate day-ahead nodal pricing results within PacifiCorp's balancing authority areas, without a financial settlement or impact to the CAISO's day-ahead market. PacifiCorp intends to use the solution results as the basis for its power cost allocation among the states within which it provides retail electric service, consistent with the expectations of the associated state public utility commissions. Under the Agreement, PacifiCorp will compensate the CAISO for the annual cost to provide the service to PacifiCorp. The CAISO requests that the Commission accept the Agreement effective March 1, 2020, so that the configuration activities can be undertaken and completed prior to implementation of the nodal pricing service on January 1, 2021.

I. Background

PacifiCorp provides retail electric service in six states,[2] and has arrangements among the state public utility commissions in which it provides electric service concerning the allocation of its power costs. The current arrangements among these state public utility commissions are set to expire at

[1] The CAISO submits the Nodal Pricing Model Agreement pursuant to Section 205 of the Federal Power Act, 16 U.S.C. § 824d.

[2] California, Oregon, Washington, Idaho, Utah, and Wyoming.

the end of 2023. PacifiCorp is seeking a third-party administered arrangement that includes a day-ahead, security-constrained economic solution upon which its power costs can be equitably allocated among the states in which PacifiCorp provides retail electric service.

PacifiCorp dispatches its system on a system-wide, least-cost basis, and then allocates the power costs to each state using an allocation factor based on its annual load. For example, if a state accounts for 25 percent of PacifiCorp total annual load then it is allocated 25 percent of the total power costs for that same year. The allocation factors are dynamic because they change annually based on each state's load. The ability to dynamically allocate power costs in a reasonable manner hinges on a common resource portfolio for which all states share proportionately in the resources. In the future, states will no longer participate in a common resource portfolio. In addition to providing a path for states to have unique resource portfolios, it is important to maintain the benefits of system dispatch and optimization as much as practicable.

PacifiCorp established guiding principles for developing a method to allocate its power costs among states. The allocation method should support individual states' abilities to have a unique resource portfolio mix that does not adversely impact other states. The allocation method should also assign costs to the state(s) that benefit from and/or drive those costs and provide appropriate incentives and transparency of cost drivers to better inform resource decision making. Finally, the allocation method should maximize the transparency of cost allocation and dispatch decisions and reduce reliance on subjective assumptions.

PacifiCorp researched multiple power cost allocation methods and concluded that most do not meet the guiding principles above. However, the nodal pricing model appears to provide the cost-benefit precision and transparency desired while adhering to the guiding principles. Under a nodal pricing model, each of PacifiCorp's six states would have its own metered load boundaries (and associated price) and a day-ahead locational marginal price associated with each of PacifiCorp resources. Accordingly, PacifiCorp sought a third party that would operate a dispatch engine to optimize PacifiCorp's day-ahead resources and create transparent nodal pricing to enable precise power cost tracking. The dispatch results would determine states' net power costs. Only PacifiCorp resources and market purchases would be included in this day-ahead nodal pricing model.

PacifiCorp and its stakeholders, which consist of utility regulatory agencies, customers, and certain others potentially affected by the power cost allocation procedures, executed a memorandum of understanding in September

2019 on this basis.[3] The memorandum of understanding supports PacifiCorp's reasonable and prudent investment of related capital funds, related operations and maintenance expenses, and the related ongoing services charges to develop and implement a nodal pricing model.

The CAISO operates the day-ahead market pursuant to the CAISO tariff, and has in place the people, processes, and technology necessary to support the bid-to-bill services associated with that market. The CAISO is able to leverage its existing technology platform, the full network model, and available data interfaces to provide PacifiCorp with a nodal pricing model solution. At the same time, PacifiCorp has developed the systems and data interfaces with the CAISO for submitting data and receiving settlement statements for participation in the energy imbalance market. Consequently, the proposed nodal pricing model would only require a modest expansion of PacifiCorp's bidding, scheduling, and settlement systems, while allowing access to the CAISO's security constrained unit commitment tool in the day-ahead timeframe. Likewise, the CAISO would need to make no significant changes to its systems beyond those needed to account for a solution that includes more than one balancing authority area.

The CAISO's technology platform and optimization engine algorithm is a highly advanced and sophisticated solution. All applicable rules, offered products, information on resources' characteristics and models, and transmission and scheduling constraints are in the CAISO's optimization tool. Leveraging these capabilities, in lieu of PacifiCorp's trying to mimic these involved and complex mathematical models and algorithms, will avoid costs that PacifiCorp would otherwise have to spend for an equivalent solution. Using a working technology platform that has proven its capabilities will reduce both schedule and budget risk, and allow for expedient implementation of the network power cost allocation methodology that PacifiCorp is seeking to implement based on the nodal pricing model solution.

Using the CAISO optimization tool will also ensure that the nodal pricing model is consistent with the actual CAISO day-ahead market since it will use the same tool, network model, and input data. Having the consistency of the solution provided by the CAISO optimization will simplify the comparison of nodal pricing model results with actual day-ahead market results. Similarly, using the same schedule data for internal and external resources impacting the calculation of both scheduled and unscheduled loop flows is critical when performing congestion management and enforcing physical flow transmission constraints. This requires significant daily effort to keep the information on generation schedules, interchange schedules, outage schedules, load forecasts, load

[3] The memorandum of understanding is included in Appendix D to a filing that PacifiCorp submitted to the Public Utility Commission of Oregon on December 3, 2019, which is available at https://edocs.puc.state.or.us/efdocs/HAA/um1050haa161935.pdf.

distribution factors, and variable energy resources forecasts up to date. Using the same tool and data will ensure that the nodal pricing solution is consistent with what the CAISO day-ahead market uses.

Finally, implementing the nodal pricing model via the CAISO's optimization tool will enable PacifiCorp to continue seamless participation in the CAISO day-ahead market by bidding at existing CAISO scheduling points. This allows the solution to account for the CAISO day-ahead cleared interchange transactions as one simultaneous optimization run. The benefit of a simultaneous run is that the resources and transmission constraints inside PacifiCorp that may impact the amount of feasible cleared interchange transactions in the CAISO's day-ahead market are dynamically enforced and accounted for inside the optimization, instead of being dealt with after the fact using another optimization tool deployed by PacifiCorp.

II. Agreement

The Agreement details the contractual terms, including the scope of work necessary to provide PacifiCorp the nodal pricing model solution it seeks, and establishes the nodal pricing model services fee that PacifiCorp will pay the CAISO to compensate for the service.

A. The Agreement Establishes the Project Scope and Schedule

Attachment A to the Agreement establishes the scope of the service and the associated implementation work.[4] The CAISO and PacifiCorp will complete certain agreed-upon tasks necessary for implementation of the nodal pricing model service on January 1, 2021. This implementation date will permit PacifiCorp's timely transition from its current network cost allocation arrangements to an arrangement supported by the CAISO's nodal pricing model that will facilitate PacifiCorp's power cost allocation. In addition, the requested March 1, 2020 effective date of the Agreement will give the parties the time and assurance required to undertake the implementation activities prior to the start of the services on January 1, 2021.

The CAISO will include the two PacifiCorp balancing authority areas (*i.e.*, PacifiCorp East (PACE) and PacifiCorp West (PACW)) in the day-ahead optimization and will model them as individual balancing authority areas to deliver the nodal pricing model solution. Using software features and a technology optimization algorithm, the day-ahead software will produce optimal unit commitment and hourly energy schedules for PacifiCorp supply resources in PACE and PACW, subject to power balance and active transmission network

[4] The parties may modify Attachment A by mutual agreement. *See* Agreement, Section 3.3.

constraints. Pursuant to the Agreement, the CAISO will be able to optimize PacifiCorp generation schedules in PACE and PACW, while maintaining complete price separation with the CAISO day-ahead market.

Energy transfers between PACE and PACW will be optimally scheduled, subject to applicable scheduling limits, whereas the net energy transfer with the CAISO will be fixed at zero to prevent energy exchange between the CAISO and PacifiCorp. This avoids any impact to the CAISO day-ahead market solution. Although the net energy transfer with the CAISO will be constrained to zero, PacifiCorp will be able to continue its participation in the day-ahead market with import/export bids at any CAISO scheduling point, the same as it does today.

The nodal pricing model will use balancing authority area-specific loss penalty factors to isolate the marginal cost of losses between balancing authority areas in the same optimization solution. Similarly, the nodal pricing model will ignore shift factors to a binding transmission constraint between balancing authority areas. This isolates the marginal cost of transmission congestion solely based on transmission congestion inside the PACE and PACW balancing authority areas for PacifiCorp's resources, and solely based on transmission congestion inside the CAISO balancing authority area.

The CAISO will also be able to produce results supporting optimal procurement of ancillary services to meet the corresponding requirements in PACE and PACW by designating these balancing authority areas as separate ancillary service regions with distinct requirements. The regional ancillary services procurement results will isolate the marginal ancillary services prices between the PACE, PACW, and CAISO balancing authority areas. The day-ahead energy schedules and ancillary services awards from the nodal pricing model solution will be ignored in the energy imbalance market.

The day-ahead settlement for the nodal pricing model solution is advisory only, *i.e.*, there will be no financially binding results. Day-ahead energy and ancillary services prices for PacifiCorp resources will be provided to PacifiCorp, but they will not be published by the CAISO. Similarly, there will be no publication of locational marginal prices, and the 6-month lagging reports the CAISO makes available will not include the day-ahead energy bids of PacifiCorp resources. This is appropriate given that the nodal pricing model solution does not involve participation in a CAISO market. Results of PacifiCorp's participation in the day-ahead market will be published pursuant to the CAISO's normal procedures.

Day-ahead price correction will apply to the day-ahead energy and ancillary services prices for PacifiCorp resources, and any corrected prices will be provided after any corrections based on the applicable price correction timelines. As part of the nodal pricing model service, the customer inquiry and

dispute system and the CAISO settlement dispute process will be available for PacifiCorp with regard to the advisory day-ahead settlement.

B. PacifiCorp Will Pay an Annual Services Fee to Compensate the CAISO for Its Ongoing Costs

The Agreement specifies that PacifiCorp will pay an annual services fee of $8.4 million, to be invoiced quarterly, for estimated costs incurred by the CAISO to perform the nodal pricing model service.[5] The annual services fee to which the CAISO and PacifiCorp have agreed is just and reasonable.[6] As discussed below, the CAISO based the fee on its estimated expenses to provide service to PacifiCorp under the Agreement. The CAISO leveraged its existing rate design model and activity-based costing system to determine the amount it will charge PacifiCorp.[7] The basis for the estimated cost is the direct and indirect time and expense necessary for the CAISO to perform the nodal pricing model service for PacifiCorp. This approach is similar to how the CAISO determines the grid management charge, the energy imbalance market administrative fee, and the reliability coordinator service charge pursuant to the CAISO tariff.

The CAISO estimated the service fee by performing a forward-looking cost of service study specifically for the nodal pricing model service. The CAISO referenced the 2016 cost of service study as the basis of the nodal pricing model study, because it is the most recent comprehensive cost of service study performed by the CAISO. The nodal pricing model study also accounts for the reliability coordinator service costs and the projected cost impacts necessary to support the nodal pricing model service.

The CAISO first estimated the associated direct operating expenses in order to project the cost necessary to support the nodal pricing model service. Labor will be the largest expense. The CAISO developed this estimate based on an analysis that considered internal resources necessary to provide the

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[5] Agreement, Section 4.1. The Agreement also allows PacifiCorp or its scheduling coordinator to dispute an invoice following payment of the full amount due. *Id.*, Section 4.2.

[6] More specifically, the annual services fee falls within the zone of reasonableness. As the Commission has explained, "the courts and this Commission have recognized that there is not a single just and reasonable rate. Instead, we evaluate [proposals under Section 205 of the Federal Power Act] to determine whether they fall into a zone of reasonableness. So long as the end result is just and reasonable, the [proposal] will satisfy the statutory standard." *Calpine Corp. v. Cal. Indep. Sys. Operator Corp.*, 128 FERC ¶ 61,271, at P 41 (2009) (citing *FPC v. Hope Nat. Gas Co.,* 320 U.S. 591, 602 (1944), and *Montana-Dakota Utils. Co. v. Northwestern Pub. Serv. Co.*, 341 U.S. 246, 251 (1951)). For the reasons explained below, the annual services fee satisfies this standard.

[7] Additional information regarding the CAISO's rate structure is available at http://www.caiso.com/Documents/DraftFinalProposal-2012GridManagementChargeFeb15_2011.pdf.

nodal pricing model service and other information related to the associated functions. The CAISO also accounted for its ability to leverage existing CAISO personnel to reduce the direct costs of the services. The CAISO can do this because it already has significant resources performing activities similar to those required to support the nodal pricing model (*e.g.*, day-ahead support staff). The CAISO thus based the total labor cost estimate on the direct hours associated with each related task that existing CAISO staff would perform paired with the personnel expenses of each of the FTE positions included in the analysis. The CAISO projects that it will need approximately 14 full-time equivalent (FTE) positions to support the service. This projection includes 6 new FTE positions and 8 existing FTE positions. The CAISO also identified the projected non-labor-related costs and mapped these costs to the nodal pricing model related tasks. These costs include nodal pricing model-specific tools and applications.

The CAISO also allocated a proportionate amount of its indirect expenses to the nodal pricing model services fee. The CAISO determined the indirect portion of the estimated expense by allocating the indirect expenses identified in the CAISO's revenue requirement proportionately based on the direct cost percentages. Indirect costs represent those costs that are not assignable to a specific task associated with a CAISO service and charged to customers who receive that service. Indirect costs include labor costs from those positions considered in an indirect, rather than a direct, supporting role, as well as other components of the revenue requirement such as administrative tools and capital. The table below breaks down the nodal pricing model services fee between direct costs (which equal the sum of the costs for new resources and existing resources) and indirect costs.

	Operating Cost ($ in millions)
New Resources	$1.20
Existing Resources	$3.64
Direct Costs	$4.84
Indirect Costs	$3.56
Total Costs	**$8.4**

As noted above, PacifiCorp has agreed to the initial level of the annual services fee. Going forward, the Agreement provides for adjustment of the annual services fee.[8] The services fee will be subject to adjustment if the parties agree to a change in the scope of the services and agree that an adjustment to the fee is warranted in light of such change. The services fee will also be subject to adjustment if the CAISO provides notice that (i) its costs to continue delivery of the service exceed the fee and (ii) the CAISO operating costs have increased by at least 2 percent since the date the services fee was most recently set. This

[8] Agreement, Section 4.1.

allows for appropriate consideration of the costs and, at the same time, provides for potential increases in the services fee if the CAISO costs increase and the increase is correlated with an overall increase in CAISO costs for services. Any adjustment will be submitted to the Commission for review. The Agreement therefore represents a reasonable balance between the parties' interest in preserving a level of cost certainty for their customers and appropriate allocation of the costs associated with the nodal pricing model solution.

C. The Agreement Ensures that the Nodal Pricing Model Solution Will Not Impact the Day-Ahead Market

The CAISO is committed to ensuring that the nodal pricing model solution does not impact the day-ahead market results, and the CAISO is confident that there will be no interactions between the nodal pricing model and the day-ahead market based on the proposed approach. However, the CAISO will not be able to demonstrate that there are no interactions prior to the simulation testing anticipated as part of the implementation. Accordingly, the parties have agreed that the CAISO may terminate the agreement prior to the start of the services if the CAISO reasonably determines that the nodal pricing model will adversely impact the day-ahead market.[9] This will give the CAISO the opportunity to test the solution and demonstrate to its reasonable satisfaction that there are no adverse interactions between the nodal pricing model and the day-ahead market. In turn, stakeholders will be assured that the PacifiCorp nodal pricing model services may commence without any impact on the results they experience in the CAISO day-ahead market. Indeed, the CAISO believes the nodal pricing model will benefit the day-ahead market by improving the information the CAISO uses to determine power flows on the system and will not have adverse interactions.

In addition, the CAISO is committed to ensuring that the nodal pricing model solution does not impact the timelines associated with the day-ahead market process. Solving for the PacifiCorp balancing authority areas will increase the scale of the solution that must solve within the specified timelines. However, the CAISO systems have the capability to produce a day-ahead solution for the entire western interconnection based on the current timelines. PacifiCorp represents only an incremental part of the total solution that the CAISO can deliver, and the CAISO does not anticipate any impact on its processing timelines. In the event there are conditions in the PacifiCorp balancing authority area(s) that potentially could delay the day-ahead processes, the CAISO would adhere to its timelines and address the PacifiCorp conditions through the same mechanisms the CAISO would use to resolve infeasibilities in its own balancing authority area. Accordingly, the CAISO will ensure that it maintains the day-ahead processing timelines while performing the nodal pricing model services set forth in the Agreement.

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9 *Id.*, Section 2.2.1.

D. The Agreement Provides a Framework to Resolve Differences That May Arise

The Agreement represents a binding commitment of the parties. As such, it must provide a workable framework for the parties to resolve any differences and correct course along the way. On the other hand, the Agreement recognizes that committing to the services is a voluntary act on the part of PacifiCorp. Accordingly, the 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. Likewise, the Agreement allows for termination by the CAISO if the parties are unable to reach agreement on a change in the annual nodal pricing model services fee or the CAISO is unable to demonstrate separation from the day-ahead market.[10] This and other related provisions mean that the parties must work closely together to achieve the goal of implementing the nodal pricing model and delivering the service on terms that remain just and reasonable.

E. Other Provisions

The Agreement includes a variety of standard provisions that round out the parties' commitment. These provisions are generally modeled on other terms and conditions accepted by the Commission with respect to CAISO *pro forma* service agreements, including some general provisions (Article V), dispute resolution (Article VI), uncontrollable forces (Article IX), and miscellaneous provisions (Article X). The limitation of liability and indemnification provisions (Article VIII) are segregated, with a commercial standard applicable to implementation and the CAISO tariff standard applicable to the service.

III. Treatment of Revenues Received Under the Agreement

The CAISO will treat all revenues it receives from PacifiCorp pursuant to the Agreement (*i.e.*, revenues for the annual nodal pricing model services fee) to offset the annual grid management charge revenue requirement. The formula used to calculate that revenue requirement includes an input for "CAISO Other Costs and Revenues", which the CAISO tariff defines to include penalties, interest earnings, and other revenues.[11] Therefore, the CAISO will include the annual services fee in this category, which includes offsets to the revenue

[10] *Id.*, Section 2.2 *et seq.*

[11] CAISO Tariff, Section 11.22.2; CAISO Tariff, Appendix F, Schedule 1, Part C.

requirement.[12] As such, the annual services fee will indirectly impact the Commission-jurisdictional rates under the grid management charge by reducing them pursuant to such offsets.

It is just and reasonable to use this existing tariff mechanism to reduce the grid management charge amounts that market participants are ultimately required to pay.[13]

IV. Effective Date

The CAISO requests that the Agreement be made effective on March 1, 2020. This will allow the parties sufficient time to complete the implementation activities prior to the service commencing on January 1, 2021.

V. Request for Waivers

The CAISO believes this filing constitutes a new service (delivery of the nodal pricing model solution) to a new customer (PacifiCorp), and is thus an initial rate schedule, subject to Section 35.12 of the Commission's rules, 18 C.F.R. § 35.12. This filing substantially complies with the requirements of Section 35.12 applicable to filings of this type. The CAISO respectfully requests waiver of any such requirement to the extent this filing does not satisfy that requirement.

Alternatively, in the event the Commission concludes that this filing is a change in a rate tariff or service agreement, the CAISO submits that the filing also substantially complies with the requirements of Section 35.13 of the Commission's rules, 18 C.F.R. § 35.13, applicable to filings of this type. In that event, the CAISO respectfully requests waiver of any such requirement to the extent this filing does not satisfy that requirement. In particular, the CAISO requests waiver of the requirement to submit Period 1 and Period 2 schedules, because, as explained above, the annual nodal pricing model services fee is based on an acceptable methodology and is subject to adjustment in the event the CAISO costs to provide the services change.

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[12] *See 2019 Budget and Grid Management Charge Rates* at 6, 55-56 (Dec. 13, 2018), available at http://www.caiso.com/informed/Pages/StakeholderProcesses/Budget-GridManagementCharge.aspx.

[13] *See, e.g.*, *Cal. Indep. Sys. Operator Corp.*, 149 FERC ¶ 61,232, at PP 5, 11 & n.9 (2014) (internal quotation marks omitted) (accepting as just and reasonable the CAISO's proposal to implement an Energy Imbalance Market administrative charge that "is not technically a GMC rate but, instead, a source of miscellaneous revenue that ultimately serves to reduce the revenue requirement").

In any event, good cause exists to waive filing requirements that are not material to the Commission's consideration of the Agreement.

VI. Service and Contents of this Filing

The CAISO has served copies of this filing upon all scheduling coordinators, PacifiCorp, the California Public Utilities Commission, and the California Energy Commission. In addition, the CAISO has posted the filing on the CAISO website.

Enclosed for filing is each of the following:

(1) This letter of transmittal; and

(2) the Agreement (Attachment A).

VII. Correspondence

The CAISO requests that all correspondence, pleadings, and other communications concerning this filing be served upon the following:

John C. Anders*
Assistant General Counsel
California Independent System
Operator Corporation
250 Outcropping Way
Folsom, CA 95630
Tel: (916) 608-7287
E-mail: janders@caiso.com

* Individual designated for service pursuant to Rule 203(b)(3), 18 C.F.R. § 203(b)(3).

VIII. Conclusion

The CAISO respectfully requests that the Commission accept this filing and permit the Agreement, CAISO Rate Schedule No. 6052, to be effective March 1, 2020. If there are any questions concerning this filing, please contact the undersigned.

Respectfully submitted,

By: *<u>/s/ John C. Anders</u>*

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Attorneys for the California Independent
System Operator Corporation

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

AND

PACIFICORP

FIRST AMENDMENT NODAL PRICING MODEL AGREEMENT

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

AND

PACIFICORP

FIRST AMENDMENT TO THE NODAL PRICING MODEL AGREEMENT

This First Amendment to the Nodal Pricing Model Agreement **("First Amendment")** is dated this 23rd day of October, 2023, and is entered into, by and between:

(1) **PacifiCorp** ("PacifiCorp"), an Oregon corporation having its registered and principal executive office at 825 NE Multnomah Street, Portland, Oregon,

and

(2) **California Independent System Operator Corporation** ("CAISO"), a California nonprofit public benefit corporation having a principal executive office located at such place in the State of California as the CAISO Governing Board may from time to time designate.

PacifiCorp and the CAISO are hereinafter referred to as the "Parties." All capitalized terms used herein and not otherwise defined shall have the meaning assigned to such terms in the Nodal Pricing Model Agreement.

Recitals:

A. Whereas, the Parties are signatories to the Nodal Pricing Model Agreement dated December 20, 2019 (the "Agreement"), which was filed with the Federal Energy Regulatory Commission ("FERC") on December 20, 2019, in Docket No. ER20-664-000. FERC accepted the Agreement effective March 1, 2020, in their letter order dated February 28, 2020, and service commenced on January 14, 2021.

B. Whereas, the Parties desire to amend the Agreement to increase the annual NPM Services Fee by ten (10) percent. Section 4.1 of the Agreement authorizes an adjustment in the annual NPM Services Fee when CAISO Operating Costs have increased by at least two (2) percent since the date the annual NPM Services Fee was previously set.

C. Whereas, in all other respects, the Parties intend that the Agreement remain in full force and effect in accordance with its terms.

NOW THEREFORE, **THE PARTIES AGREE** as follows:

1. Effective Date. This First Amendment shall be effective on the date made effective by FERC.

2. Termination. This First Amendment shall remain in full force and effect until the termination of the Agreement.

3. First Amendment to the Agreement. The Agreement shall be amended as follows:

3.1 Section 4.1: Payment for NPM Services is deleted in its entirety and replaced with the following:

"4.1 Payment for NPM Services. PacifiCorp shall pay the CAISO an annual fee of $9.24 million for costs incurred by the CAISO to perform the NPM Services (the "NPM Services Fee"). The NPM Services Fee will be subject to adjustment in either of the following circumstances: (1) if the Parties agree to a change in Attachment A in accordance with Section 3.3 and agree an adjustment to the NPM Services Fee is warranted in light of such change; or (2) the CAISO provides notice to PacifiCorp that its costs to continue delivery of the NPM Services exceed the NPM Services Fee and the CAISO Operating Costs have increased by at least two percent (2%) since the date the NPM Services Fee was most recently established and agreed upon by the Parties; provided, however, that a change in the NPM Services Fee under this clause (2) may not occur more frequently than annually. The CAISO will invoice PacifiCorp or its Scheduling Coordinator for the NPM Services Fee quarterly. Invoicing, including disputes, will be addressed by PacifiCorp or its Scheduling Coordinator."

4. This First Amendment constitutes the complete and final agreement of the Parties with respect to the purpose of this First Amendment as described in the Recitals hereto and supersedes all prior understandings, whether written or oral, with respect to such subject matter.

5. Except as expressly modified in this First Amendment, the Agreement shall remain in full force and effect in accordance with its terms, and the unmodified provisions of the Agreement shall apply to any new rights and/or obligations established by this First Amendment.

6. This First Amendment may be executed in one or more counterparts at different times, each of which shall be regarded as an original and all of which, taken together, shall constitute one and the same agreement.

IN WITNESS WHEREOF, the Parties have caused this First Amendment to be duly executed by and through their respective authorized representatives as of the date hereinabove written.

California Independent System Operator Corporation

By: DocuSigned by: Khaled Abdul-Rahman 018C508C28F6464...

Name: Khaled Abdul-Rahman

Title: Vice President

Date: 10/23/2023

PacifiCorp

By: DocuSigned by: Michael Wilding 0AFF310D9C284F3...

Name: Michael Wilding

Title: VP, Energy Supply Management

Date: 10/23/2023

AWEC Data Request 042

Reference work paper "Exhibit PAC 102 - Net Power Costs Report," Excel Row 216 "EDAM and EIM Imports/Exports":

(a) Please provide the work papers supporting the calculation of EIM benefits reflected in the referenced row, along with an explanation of how those benefits were derived.

(b) Please provide historical EIM benefits over the period 2020 through 2024, including work papers supporting the calculation of those benefits, on a plant by plant, or the most granular, level available.

(c) Please explain how PacifiCorp calculates historical EIM benefits.

(d) If PacifiCorp uses a third-party consultant to perform the calculation of historical EIM benefits, please provide all project deliverables received from said consultant over the period January 1, 2023, through December 31, 2024.

(e) Please provide actual historical EIM settlements by charge code and month over the period January 1, 2020, through December 31, 2024.

(f) Please provide work papers used to calculate the EDAM benefits reflected in the referenced row.

Response to AWEC Data Request 042

(a) Please refer to Confidential Attachment "_UE 450_CONF_PACtoAWEC_IR042R_Attach1" which provides copies of the work papers used to calculate Western Energy Imbalance Market (WEIM) benefit forecasts for 2026. Please refer to the direct testimony of Company witness, Vijay Singh, which provides a description of how PacifiCorp forecasts WEIM benefits.

(b) PacifiCorp objects to this request as overly broad, unduly burdensome and not reasonably calculated to lead to the discovery of admissible evidence. Without waiving any objection, the Company responds as follows:

Please refer to Confidential Attachment "_UE 450_CONF_PACtoAWEC_IR042R_Attach2" which provides historical WEIM benefits by balancing area (BA) and transfer direction. The column named "Sum of Margin" contains the monthly historical WEIM benefits.

Note: the third-party vendor that calculates PacifiCorp's WEIM benefits, Yes Energy, does not use plant level data for calculating WEIM benefits. The data provided is in monthly granularity.

(c) PacifiCorp uses a third-party vendor, Yes Energy, to calculate WEIM benefits. The vendor's calculation mirrors the transfer cost, greenhouse gas (GHG) revenue, and GHG cost calculations used by the California Independent System Operator (CAISO).[1]

(d) PacifiCorp assumes the term "project deliverables" to mean any files produced by Yes Energy related to WEIM benefits. As such, PacifiCorp objects to this request as overly broad, unduly burdensome and not reasonably calculated to lead to the discovery of admissible evidence. Without waiving any objection, the Company responds as follows:

WEIM benefit files produced by Yes Energy benefits are aggregated for determining monthly WEIM benefits. The monthly WEIM benefits are then used in PacifiCorp's WEIM benefit forecasting models.

(e) Please refer to Confidential Attachment "_UE 450_CONF_PACtoAWEC_IR042R_Attach4_05192025" which provides the actual historical EIM settlements by charge code and month for the period of January 1, 2020, through December 31, 2024.

(f) Please refer Confidential Attachment: "_UE 450_CONF_PACtoAWEC_IR042R_Attach3_05192025" which provides the data used to formulate the Extended Day-Ahead Market (EDAM) values in Exhibit PAC 102 (Net Power Costs Report), row 216 "EDAM and EIM Imports/Exports"

Confidential information is designated as Protected Information under Order No. 23-132 and may only be disclosed to qualified persons as defined in that order.

[1] See https://www.westerneim.com/Documents/EIM-BenefitMethodology.pdf

AWEC Data Request 045

The Brattle study states the following: "EDAM Congestion and Transfer Revenues: are collected by the EDAM market administrator (CAISO) and allocated back to market members as specified in the EDAM design. In the market, generators are paid the price at their location, which is accounted for in the [Adjusted Power Costs (APC)] calculation as revenue from market sales. Similarly, load pays the price at its location, also accounted for in the APC metric as the cost of purchased power. However, due to congestion on the system when trading between member BAAs, the locational price paid by load in most instances is higher than the locational price paid to generators. Therefore, on EDAM transactions between member BAAs, the money collected from load is typically greater than the money paid out to generators. The EDAM design mandates that this additional money be allocated back to member BAAs. The same process is in place today in the WEIM, and WEIM members currently receive allocations of congestion revenues collected in the market." Please explain why congestion revenues were not otherwise already reflected in adjusted power cost in the Brattle model.

Response to AWEC Data Request 045

The Brattle Group's (Brattle) description of why transfer revenues are not accounted for in the Adjusted Power Cost (APC) is the same rationale for why congestion revenues are not already reflected in APC in the Brattle study. Congestion internal to BAAs can also cause the locational price paid by loads to be higher than the locational price paid to generators. Therefore, the money collected from loads will be greater than the money paid to generators. This is not captured in APC since the metric captures revenues from market sales and costs of purchased power. Like transfer revenues, congestion revenues are allocated back to EDAM BAAs in the Brattle study as a separate benefit than the benefit that accrues to EDAM BAAs due to lower APC.

AWEC Data Request 059

Reference PacifiCorp's response to AWEC Data Request 35: The referenced response is not responsive. The request asked for the work papers supporting the line loss calculations. PacifiCorp only provided the line loss factors that were used. Please provide the work papers used to derive the values in the attachment provided in the referenced response.

Response to AWEC Data Request 059

Please refer to attachment "_UE 450_NONC_PACtoAWEC_IR059 Attach 06112025" which provides the loss factors and the associated work papers used in the load forecast in this 2026 Transition Adjustment Mechanism (TAM) proceeding.

Line Lossses by Jurisdiction

Oregon	9.93%
Washington	10.57%
California	10.42%
Utah	4.15%
Idaho	5.29%
Wyoming PPL	9.12%
Wyoming UPL	3.26%

		Pacific Power				Rocky Mountain Power			5 Year Monthly Average 2019-2023						
		Oregon	Washington	California	Utah	Idaho	Wyoming PPL	Wyoming UPL	Oregon	Washington	California	Utah	Idaho	Wyoming PPL	Wyoming UPL
Total 2023	System Load	15,409,341	4,339,714	852,445	26,745,093	3,587,417	8,187,175	1,311,656							
	Sales	13,949,228	3,850,048	760,415	26,062,338	3,495,580	7,326,238	1,252,481							
	Line Loss	10.5%	12.7%	12.1%	2.6%	2.6%	11.8%	4.7%	9.93%	10.57%	10.42%	4.15%	5.29%	9.12%	3.26%
Total 2024	System Load	15,154,156	4,646,416	879,485	27,217,232	3,849,161	8,264,783	1,217,769							
	Sales	13,700,592	4,181,079	799,528	26,109,777	3,706,984	7,510,221	1,155,915							
	Line Loss	10.6%	11.1%	10.0%	4.2%	3.8%	10.0%	5.4%							
Total 2021	System Load	14,839,651	4,591,029	865,826	26,866,196	3,719,643	8,019,121	1,249,553							
	Sales	13,510,323	4,198,961	798,075	25,657,420	3,552,489	7,335,411	1,221,255							
	Line Loss	9.8%	9.3%	8.5%	4.7%	4.7%	9.3%	2.3%							
Total 2020	System Load	14,170,716	4,457,782	845,246	25,994,468	3,828,650	7,516,114	1,395,034							
	Sales	12,993,459	4,065,151	758,823	24,850,549	3,534,206	6,968,337	1,389,453							
	Line Loss	9.06%	9.66%	11.39%	4.60%	8.33%	7.86%	0.40%							
Total 2019	System Load	14,353,220	4,559,396	815,759	25,607,255	3,727,022	8,217,166	1,745,168							
	Sales	13,088,664	4,144,590	740,931	24,490,305	3,485,476	7,706,847	1,685,794							
	Line Loss	9.7%	10.0%	10.1%	4.6%	6.9%	6.6%	3.5%							

AWEC Data Request 060

Reference PacifiCorp's response to AWEC Data Request 35, Attachment _UE 450_NONC_PACtoAWEC_IR035R_Attach_05192025": Please provide a detailed explanation for how the line loss factors in the referenced workpaper were calculated.

Response to AWEC Data Request 060

The line loss factors are calculated as the average of the most recent five years (2019 through 2023) of the annual load at generation over retail sales. (Load/Retail -1). The average losses are then rounded to four decimal places.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 450

In the Matter of	)
	)
PACIFICORP	)
	)
2026 Transition Adjustment Mechanism.	)
	)

CONFIDENTIAL EXHIBIT AWEC/103

WEIM CONGESTION REVENUE ANALYSIS

PROTECTED INFORMATION

SUBJECT TO GENERAL PROTECTIVE ORDER

Exhibit AWEC/103 contains Protected Information Subject to General Protective Order No. 23-132 and has been redacted in its entirety.