ORDER NO. 23-404

ENTERED Oct 27 2023

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 420

In the Matter of PACIFICORP, dba PACIFIC POWER, 2024 Transition Adjustment Mechanism	ORDER

DISPOSITION: STIPULATION ADOPTED; RECOVERY OF CERTAIN COSTS DENIED

I. SUMMARY

In this order, we adopt a contested Stipulation that resolves most issues among the parties regarding PacifiCorp, dba Pacific Power's 2024 Transition Adjustment Mechanism. We adopt the parties' agreement to decrease PacifiCorp's filed TAM by $18.8 million, $5.5 million of which is attributable to removal of costs attributable to the Ozone Transport Rule and $13 million of which is an unspecified black box reduction. We are not persuaded by arguments opposing the Stipulation and find that this falls within the range of just and reasonable rates.

In addition, two contested issues remained that were not covered by the Stipulation—costs related to compliance with the Washington Climate Commitment Act (CCA) and certain coal issues raised by Sierra Club. We disallow the Washington CCA costs as a state-specific initiative that is properly allocated to Washington under PacifiCorp's Multi-State Process. We do not order any adjustments related to Sierra Club's coal issues.

II. BACKGROUND AND PROCEDURAL HISTORY

On April 3, 2023, PacifiCorp filed its 2024 Transition Adjustment Mechanism and associated documents. PacifiCorp stated that its proposed change in net power costs would affect approximately 652,000 customers and result in an overall annual increase of approximately $163.8 million or 9.5 percent. Residential customers using 900 kilowatt-hours would see an average monthly bill increase of $9.58 per month were the change to go into effect. The Company states that there are four main drivers of the increase:

1) Power, natural gas, and coal prices for calendar year 2023 have increased by an average of 31 percent, 20 percent, and 12 percent respectively.
2) The TAM now includes the impact of the Washington Cap and Invest program and the Ozone Transport Rule.
3) The hedges in the 2023 TAM were favorable to the current calendar year 2023 prices from the official forward price curve used in this filing.
4) The calendar year 2023 Oregon load projections used to calculate the 2023 TAM net power costs were substantially lower than the current calendar year 2023 load projections.[1]

Numerous parties intervened in this proceeding, namely the Alliance of Western Energy Consumers (AWEC), Calpine Solutions, LLC, the Klamath Water Users Association (KWUA), the Oregon Citizens' Utility Board (CUB), Sierra Club, and Vitesse. The intervenors in this proceeding, as well as Staff of the Oregon Public Utility Commission, filed their opening testimony on June 23, 2023. PacifiCorp filed its reply testimony on July 24, 2023; rebuttal testimony was filed on August 16, 2023; and PacifiCorp's surrebuttal was filed on August 30, 2023.

On September 7, 2023, prior to the start of the evidentiary hearing in this proceeding, the parties informed the Administrative Law Judge that a number of parties had reached a Partial Stipulation covering most, but not all, of the issues in the case. The parties then proceeded to have an abbreviated evidentiary hearing on September 7, 2023, and September 8, 2023, while scheduling an additional evidentiary hearing on the opposed Partial Stipulation. PacifiCorp filed the Partial Stipulation as well as a supporting brief on September 12, 2023.

III. THE STIPULATION

The Stipulation resolves all issues in the proceeding except: (1) the coal modeling issues raised by Sierra Club; and (2) issues related to compliance with the Washington Climate Commitment Act. It was joined by PacifiCorp, Staff, CUB, Calpine, KWUA, and Vitesse. Sierra Club and AWEC did not join the Stipulation and AWEC opposes it.

The Stipulation agrees to an $18.5 million decrease to net power costs on an Oregon-allocated basis. Of the decrease, $5.5 million is attributable to removal of costs related to compliance with the Ozone Transport Rule. The remaining $13 million is an unspecified black box reduction. This results in a baseline net power costs of $703.6 million Oregon-allocated, and an overall rate increase of $112.3 million, subject to the final update. That is a 6.5 percent increase, down from 9.5 percent in the initial filing.

[1] PAC/100, Mitchell/7-8

In the Stipulation, PacifiCorp agrees to hold workshops to discuss the modeling, inputs, and forecasting of the following topics, including how these topics are modeled in Aurora:

a. Coal contracting;
b. Coal dispatch;
c. Day-ahead and Real-time (DA/RT) Adjustment;
d. Wind forecasting;
e. Short-term transmission; and
f. Extended Day-Ahead Market/EIM.

It also agrees to provide certain information in the 2023 Power Cost Adjustment Mechanism (PCAM) regarding the operation of PacifiCorp's coal facilities. In particular, PacifiCorp will provide information regarding the forecasted and actual generation per plant, coal consumed per plant, and price of coal consumed for the month at each plant. It will also provide an explanation for variances in forecasted generation greater than 10 percent from the forecast on a monthly and annual basis.

The Stipulation also provides that if the combined January 1, 2024, rate increases from the 2024 TAM, 2022 PCAM, and any other rate change exceeds 15 percent, PacifiCorp will seek to delay the rate effective date of revised Schedule 206, the PCAM tariff, until April 1, 2024.

The Stipulation addresses the DA/RT adjustment in calculating the transition charge, stating that PacifiCorp will apply the adjustment for market prices used for valuing changes in generation for months when the net change in the Company's generation is a reduction of generation attributable to direct access. For other months, PacifiCorp will not apply the market adjustment to the net generation increase but will value it at cost.

IV. APPLICABLE LAW

ORS 757.210 establishes the applicable standard and burden of proof. It provides that, in a rate case, "the utility shall bear the burden of showing that the rate or schedule of rates proposed to be established or increased or changed is fair, just and reasonable." Thus, PacifiCorp must submit evidence showing that its proposed rates, including the terms and conditions of service, are just and reasonable. The Commission must also determine that stipulations result in just and reasonable rates; the parties to that stipulation have the burden of making that demonstration.

V. OPPOSITION TO THE STIPULATION

A. Positions of the Parties

AWEC opposes the Stipulation, arguing that the Stipulating Parties have failed to meet their burden to demonstrate that the terms of the Stipulation are just and reasonable. In particular, AWEC points to a change that PacifiCorp made to its DA/RT modeling in its reply testimony that it characterized as a correction. That change was purportedly to remove unsupported artificial arbitrage revenue from the DA/RT volume component and increased net power costs by $61 million, company-wide. AWEC takes issue with the characterization of this change as a correction and states that the TAM Guidelines are clear that methodological changes in a stand-alone TAM filing are only allowed in the Initial Filing. AWEC points as well to Staff's Rebuttal Testimony where it characterizes the change as a "*change* to the modeling that should not have been labeled as a correction."[2]

AWEC states that the value of this issue to Oregon ratepayers is approximately $17.5 million, and thus that it "overwhelms the 'unspecified' adjustment of $13 million" in the Stipulation.[3] AWEC continues that the give and take process in settlement "does not obviate the requirement of the Stipulating Parties' obligation to 'present evidence that the stipulation is in accord with the public interest, and results in just and reasonable rates.'"[4]

AWEC also cites Staff's opposition to using PacifiCorp's "average of the averages" method to identify proposed market caps within the Aurora modeling system, which Staff Witness Dlouhy opposed in his testimony. AWEC states that "at best, the value of the market cap modeling approach is included within the $13 million 'unspecified monetary adjustment' though this inclusion would further dilute any value received for the DA/RT modeling change discussed above. At worst, Staff abandoned its advocacy for this Commission-approved modeling method entirely."[5]

The settling parties filed testimony arguing that black box settlements are a legitimate way to resolve contested cases and that the Commission reviews settlements on a holistic basis to determine whether they result in a just and reasonable rate and are in the public interest. Accordingly, the Commission "need not evaluate each individual adjustment, theory, or methodology proposed by the parties, but may review the reasonableness of the overall rates, recognizing that a stipulation may represent a compromise of different

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[2] Staff/800, Jent/8 (emphasis in original).
[3] AWEC Response to Stipulating Parties Joint Brief at 10.
[4] *Id.* at 10 (quoting Order No. 22-129 at 17).
[5] *Id.* at 11.

positions."[6] In this case, they argue, there is voluminous evidence in the record to support the overall reasonableness of the rates that was filed over the course of this proceeding. The fact that the $13 million disallowance falls in the middle of the range of outcomes supported by parties in this proceeding it is "both reasonable and supported by substantial evidence."[7]

B. Resolution

We find that the Stipulation is supported by substantial evidence and will result in just and reasonable rates and therefore we approve it. We agree with the stipulating parties that we have never required a demonstration that each individual rate component contained within a black box settlement is just and reasonable. As we stated in one such case:

> When considering a stipulation, we have the statutory duty to make an independent judgment as to whether any given settlement constitutes a reasonable resolution of the issues. We have recognized, however, that issues in a general rate case typically reflect judgments along a continuum of outcomes and can rarely be reduced to one 'right' number in any cost category. When considering a stipulation, therefore, we may evaluate the validity of the rates based on the reasonableness of the overall rates, not the theories or methodologies used or individual decisions made.[8]

Indeed, black box stipulations are commonly employed as a means to resolve proceedings before the Commission, including in numerous past TAM proceedings.[9]

Here, the stipulating parties agreed to a black box reduction of $13 million. Staff had quantified its adjustments in this proceeding as $31 million and supports the Stipulation as "within the scale of what Staff proposed."[10] The largest Staff adjustment—and one with which AWEC takes particular issue not being included in the Stipulation in its entirety—is $21.7 million related to a modeling change (Staff and intervenors' view) or

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[6] *In the Matter of PacifiCorp, dba Pacific Power, 2012 Transition Adjustment Mechanism*, Docket No. UE 227, Order No. 11-435 at 3 (Nov. 4, 2011) (internal citations omitted).
[7] Joint Stipulation Parties/100, McVee, Mitchell, Kim, Jenks, Higgins, Johnson/5.
[8] *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision,* Docket No. UE 210, Order No. 10-022 at 6 (Jan 26, 2010) (internal citations omitted).
[9] *See In the Matter of PacifiCorp, dba Pacific Power, 2019 Transition Adjustment Mechanism*, Docket No. UE 339, Order No. 18-421 at 1, Appendix A at 3 (Oct. 26, 2018) ($11.8 million unspecified adjustment); *In the Matter of PacifiCorp, dba Pacific Power, 2020 Transition Adjustment Mechanism*, Docket No. UE 356, Order No. 19-351 at 3 (Oct. 30, 2019) ($4.9 million unspecified monetary adjustment); *In the Matter of PacifiCorp, dba Pacific Power, 2021 Transition Adjustment Mechanism*, Docket No. UE 375, Order No. 20-392 at 2 (Oct. 30, 2020) ($2.25 million unspecified monetary adjustment); *In the Matter of PacifiCorp, dba Pacific Power, 2023 Transition Adjustment Mechanism*, Docket No. UE 400, Order No. 22-389 at 3 (Oct. 25, 2022) ($4.9 million unspecified monetary adjustment).
[10] Joint Stipulating Parties/100, McVee, Mitchell, Kim, Jenks, Higgins, Johnson/11.

an error correction (PacifiCorp's view) in PacifiCorp's reply testimony. In AWEC's view, this is a straightforward violation of the TAM guidelines which prohibit modeling changes in updates.

Staff testifies that the resolution of this issue, as well as the next largest issue regarding the method for establishing market caps, "would not have been decided on the appropriate application of well-established ratemaking principles, but on subjective questions of interpretation the Commission would have the discretion to resolve either way."[11] AWEC itself notes that the TAM guidelines do not define what constitutes a "modeling change" versus a "correction."[12] And PacifiCorp submitted testimony in this case maintaining that it was a correction because the model was functioning erroneously prior to the change.[13] It also noted that "the entirety of the Company's NPC forecast is a model so almost any correction can be considered a change to the model relative to the Initial Filing."[14]

Given this testimony and given our holistic review of the rates at issue, we find the $13 million black box reduction, combined with the $5.5 million reduction to account for removal of the Ozone Transport Rule costs, results in rates within the range of just and reasonable rates and therefore we approve the Stipulation. We note as well that PacifiCorp has agreed to host workshops on a variety of issues where some intervenors filed testimony stating more information would be useful before the Commission reaches a precedential decision, which will aid us in determining whether rates are in the range of just and reasonable rates going forward. Accordingly, the Stipulation is approved.

VI. CONTESTED ISSUES

There are two issues that are not addressed in the Stipulation. The first is the question of how to handle costs related to compliance with the Washington Climate Commitment Act. The second is resolution of Sierra Club's proposals related to the Jim Bridger coal plant.

A. Washington Climate Commitment Act Costs

The Washington Climate Commitment Act (CCA) establishes regulatory requirements to reduce greenhouse gas (GHG) emissions from generating plants in Washington. One component of the CCA, the Cap and Invest Program, "caps" emissions in the state of

[11] Joint Stipulation Parties/100, McVee, Mitchell, Kim, Jenks, Higgins, Johnson/12.
[12] AWEC Brief in Opposition at 3.
[13] PAC/800, Mitchell/22-23 (stating "[a] calculation that is designed to simulate *costs* associated with real-world trading *inefficiencies* but which produces substantial ($97 million) and unrealistic *revenue* is clearly producing an erroneous result.").
[14] PAC/800, Mitchell/23. This testimony also notes a correction PacifiCorp included in its Reply Update that constituted a modeling change to more accurately reflect "thermal generation marginal costs" and which decreased net power costs by $75 million company-wide.

Washington. The Washington Department of Ecology (Ecology) then distributes emissions allowances to entities that, like PacifiCorp, are subject to the Clean Energy Transformation Act (CETA); a compliance instrument like an allowance is required for every metric ton of carbon dioxide a facility emits.

PacifiCorp owns and operates the natural gas Chehalis generating facility, which emits substantial amounts of carbon dioxide and for which it is required to retire allowances. The Company also receives no-cost allowances from Ecology, which it has been directed by Ecology to allocate only to Washington state retail customers. Therefore, Oregon customers are paying for the costs of complying with the Washington CCA but not receiving a share of the allowances that Washington customers receive to mitigate the costs of that compliance.

1. Positions of the Parties

Both Staff and AWEC object to inclusion of PacifiCorp's CCA compliance costs in Oregon rates, arguing that PacifiCorp should not be able to recover the costs of compliance with the CCA when it is receiving allowances that are only allocated to Washington customers. AWEC argues that this constitutes a violation of the dormant commerce clause of the Constitution. Staff argues that PacifiCorp is violating the Multi-State Process (MSP) that the Commission has approved to govern cost-allocation between PacifiCorp's different jurisdictions.

AWEC argues that consistent with the dormant commerce clause of the Constitution, courts have held that states may generally not adopt or enforce laws that discriminate against out-of-state entities on their face, in their purpose, or in their practical effect, or which place a significant burden on interstate commerce that is "clearly excessive in relation to putative local benefits."[15] AWEC argues that the CCA is "facially discriminatory in that it explicitly favors in-state interests over out-of-state interests by providing free allowances to PacifiCorp for in-state emissions associated with its Washington retail load but allocates no free allowances for in-state emissions associated with retail load of other jurisdictions."[16]

PacifiCorp argues that dormant commerce clause claims are not properly before the Commission. PacifiCorp argues that Oregon administrative agencies can determine the constitutionality of statutes that they are charged with enforcing; but that they should not consider the constitutionality of statutes from another state that they have no jurisdiction over. PacifiCorp also states that this issue is already ripe for resolution in a Washington federal court.[17] AWEC, however, argues that this is relevant to ratemaking because

[15] *Rocky Mountain Farmers Union v. Corey*, 730 F3d 1070, 1087 (9th Cir 2013).
[16] AWEC Opening Br. at 4.
[17] *Invenergy Thermal LLC v. Watson*, Case No. 3:22-cv-5967-BHS, Complaint at 4-5 (WD Wash Dec. 13, 2022).

PacifiCorp itself should have challenged the constitutionality of Ecology's decision regarding allocation of the no-cost allowances instead of attempting to recover costs from Oregon customers in rates.

Meanwhile, Staff argues that PacifiCorp's recovery of costs from Oregon customers violates the MSP, and specifically that the Washington CCA is a state-specific initiative that must be recovered by Washington customers alone. Staff points to Section 3.1.2.1 of the MSP, which states:

> State-Specific Initiatives: Resources acquired in accordance with a State-specific initiative will be allocated and assigned on a situs basis to the State adopting the initiative. State-specific initiatives include, but are not limited to, the costs and benefits of incentive programs, net-metering tariffs, feed-in tariffs, capacity standard programs, solar subscription programs, electric vehicle programs, and the acquisition of renewable energy certificates.

PacifiCorp argues that the CCA is actually a tax or that it constitutes generation-dispatch costs, both of which are properly allocated to all states that benefit from the generation in question. It cites the example of a tax on wind generation imposed by Wyoming, which Staff agrees is properly allocated among states receiving that wind power. In general, PacifiCorp cites to a variety of programs in its states, including Oregon, that are allocated across state lines, including the California Cap and Trade program that is in many ways similar to Washington's program. Further, PacifiCorp argues that Oregon ratepayers are benefitting from the Chehalis plant and therefore should pay the costs of operating it, which includes the costs of complying with the Washington CCA.

2. Resolution

We agree with Staff that the costs of the Washington CCA should be situs assigned under the MSP. PacifiCorp's argument to the contrary is overly formalistic—it argues that Staff improperly conflates CETA, a portfolio standard, with the CCA, not a portfolio standard. PacifiCorp does not address the interplay between the two statutes, and that interplay makes clear that the costs in question should be situs assigned.

PacifiCorp's testimony describes the operation of the CCA and CETA at some length. The CCA sets emissions targets (*e.g.*, 95 percent below 1990 levels by 2050) and establishes an annually decreasing cap until that level is reached. Entities can buy, sell, and trade allowances with permitted CCA emissions that fall under the cap. The CCA also calls for distribution of no-cost allowances specifically to utilities subject to CETA, like PacifiCorp.[18]

The CCA requires that the Company demonstrate compliance by retiring GHG allowances for any GHG emissions from generators within the state, even when the energy is exported outside of Washington. For PacifiCorp, the only thermal generator within Washington is the Chehalis gas plant. Ecology has been clear that the allowances PacifiCorp receives for Chehalis must be distributed to Washington retail load alone. It stated that, "the plain language of the law and legislative intent is clear that the concept of cost burden relates to how the costs associated with covered emissions are passed on to customers in the State of Washington."[19] It continues that it recognizes the complication associated with protocols for regulated utilities serving multiple states, and that "[i]t is expected that those protocols will be applied through the existing means in the rule language, and that a Washington-specific allocation is possible."[20]

Moreover, the state has been specific about the link between CETA and the CCA. In federal district court litigation concerning the CCA, Ecology discussed the link between CETA and the CCA and the reasoning behind distributing no-cost allowances for the benefits of Washington retail customers:

> [T]he Clean Energy Transformation Act (CETA), requires utilities serving Washington customers to reduce their greenhouse gas emissions to neutral by 2030 and to zero by 2045. Critically, these requirements do not apply to generation for out-of-state customers. Thus, the function of the no cost allowances in the Climate Commitment Act is to avoid double-charging Washington customers for the costs of the energy transition to non-emitting generation.[21]

As Staff points out in its brief, the provision of cost-free allowances phases out over time and sunsets in 2045, the same year that CETA requires Washington electric utilities to have phased out fossil fuel generators from their portfolios.[22]

In short, while portions of the CCA might, if they existed in isolation, constitute a tax or could be characterized as generation-dispatch costs, the program viewed as a whole goes beyond this by providing cost-free allowances to Washington retail customers alone

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[18] WAC 173-446-230(2)(a)-(b).
[19] State of Washington, Dep't. of Ecology, Publication 22-02-046, *Concise Explanatory Statement,* Chapter 173- 446 WAC Climate Commitment Act Program, (Sept. 2022), available at: https://apps.ecology.wa.gov/publications/documents/2202046.pdf.
[20] *Id.*
[21] *Invenergy Thermal* LLC*, and Grays Harbor Energy LLC v. Laura Watson*, in her official capacity as Director of the Washington State Department of Ecology, Defendant, ("*Invenergy v. Ecology*") Defendant's Motion to Dismiss, (Feb. 16, 2023), Western District of Washington Case No. 3:22-cv-05967
[22] RCW 70A.65.120(2)(d); RCW 19.405.010(2).

during the path to full CETA compliance in 2045. The end result is a program that implements a state-specific initiative by creating portfolio standards under CETA and then distributing allowances to CETA-obligated utilities under the CCA. The MSP is designed to isolate state-specific electricity policy costs like this one. The fact that Ecology itself stated in federal court that the purpose of the no-cost allowances was to avoid double-counting under CETA makes the connection to the portfolio standards particularly clear.

We understand the position that this conclusion puts PacifiCorp in; and the Company was given guidance by Ecology stating that the no-cost allowances must be allocated only to Washington customers. Accordingly, PacifiCorp is faced with conflicting instructions about cost allocation. However, that does not mean that it becomes appropriate to charge Oregon retail customers for those costs instead. The remedy for this issue falls in the Washington legislature, in the courts, or in the MSP process.

Because we agree with Staff that the costs of CCA compliance from which the interaction with CETA shields Washington customers should be situs-assigned under the MSP, we do not need to decide the merits of AWEC's dormant commerce clause argument.

B. Sierra Club Coal Issues

The Jim Bridger coal plant is located in Wyoming. PacifiCorp files a Long Term Fuel Supply Plan for Jim Bridger with the Commission every two years, with its IRP. Sierra Club takes issue with the fuel supply plan that accompanied PacifiCorp's latest IRP, which is at issue in this proceeding, and with PacifiCorp's selection of a preferred operating scenario in that plan.

1. Positions of the Parties

Sierra Club argues that PacifiCorp should: (1) be directed to adopt Scenario 4 of its Long-Term Fuel Supply Plan as its Preferred Scenario instead of Scenarios 5 and 6; and (2) be directed to update its Long-Term Fuel Supply Plan every year instead of every other year.

As to the first, PacifiCorp's examined six scenarios, concluding that Scenarios 5 and 6 were functionally equivalent:

[BEGIN HIGHLY CONFIDENTIAL INFORMATION]

[redacted]

[redacted]

[END HIGHLY CONFIDENTIAL INFORMATION]

Sierra Club argues that PacifiCorp's analysis of the preferred scenarios contains significant errors and that it does not properly minimize Oregon's reliance on high-cost Bridger coal. In particular, Sierra Club argues that PacifiCorp has independent incentives to avoid accelerated closure of the Bridger mine that could ultimately lead to Jim Bridger closing early due to the potential to make capital investments in the plant on which it can earn a return. It also argues that the cost differences between Scenarios 4 and 5/6 are *de minimis* after considering the flaws in PacifiCorp's analysis that Sierra Club presented in its testimony, including inclusion of 2023 costs in the 2024 TAM, include unsupported cost assumptions that do not align with previous cost assumptions, and an unexplained increase in "other generation" in Scenarios 5/6 over Scenario 4.

Finally, Sierra Club notes that a significant amount of the differential between Scenarios 5/6 and Scenario 4 are post-2024 benefits, which it believes should be given reduced weight when the prudence of the 2023 TAM is considered. Ultimately, when only 2024 benefits are taken into account, Sierra Club argues that the differential between Scenarios 5/6 and Scenario 4 is entirely attributable to increased wholesale sales. Sierra Club notes that these sales may not materialize. Sierra Club thus "questions the prudency of encouraging PacifiCorp to produce more coal generation for off-system sales when Oregon is seeking to curb its own greenhouse gas emissions and eliminate coal from rates."[23]

As to the second issue, Sierra Club argues that yearly updates are needed to the Long-Term Fuel Supply Plan due to the volatile and changing conditions in the energy markets and the fact that "a prudent utility continuously evaluates whether its current investments make the most economic sense for ratepayers."[24]

PacifiCorp opposes both recommendations. First, it argues that it properly included 2023 costs in its analysis since that was the first year of the planning horizon and that that contributes a minimal amount to the difference between scenarios. Second, it argues that the difference in "other generation" is due to **[BEGIN HIGHLY CONFIDENTIAL INFORMATION]** [redacted]

[23] Sierra Club Opening Brief at 10.
[24] *Id.* at 11.

[redacted] **[END HIGHLY CONFIDENTIAL INFORMATION]** Finally, it argues that Sierra Club's other arguments about the cost differential between scenarios are speculative and unsupported.

PacifiCorp also opposes filing an annual fuel plan, stating that it would be impractical to prepare an annual plan given that the plan covers multiple years and requires large-scale analysis. It also says that it is reasonable to time the fuel plans with the IRP because the IRP relies on data developed for the fuel plan, and the fuel plan relies upon the resource mix in the preferred portfolio from the IRP filing.

2. Resolution

We are not persuaded that PacifiCorp should be ordered to adopt Scenario 4 instead of Scenarios 5/6. First, we do not consider the cost differential between the two scenarios to be *de minimis*. While Sierra Club did point to potential errors in PacifiCorp's cost analysis, we find that PacifiCorp generally had satisfactory answers regarding the discrepancies—or that they were not of a magnitude to change the relative cost effectiveness of Scenario 4 vs. Scenarios 5/6. For example, Sierra Club points to a decrease in the cost of BCC incremental coal in 2027 and 2028. PacifiCorp explains that **[BEGIN HIGHLY CONFIDENTIAL INFORMATION]** [redacted] **[END HIGHLY CONFIDENTIAL INFORMATION]** Separately, Sierra Club points to the fact that Scenarios 5/6 have higher "other" generation totals than Scenario 4, even though Jim Bridger is also operating more in Scenarios 5/6. PacifiCorp explains that this is related to its use of its coal stockpile. At any rate, Sierra Club does not quantify the magnitude of the error and it is not clear to us that it is sufficient to significantly narrow the gap between Scenario 4 and Scenarios 5/6.

Second, we believe PacifiCorp reasonably explained at hearing the need for more flexibility. In Scenarios 5/6, the Bridger mine will **[BEGIN HIGHLY CONFIDENTIAL INFORMATION]** [redacted] **[END HIGHLY CONFIDENTIAL INFORMATION]**. This increase in flexibility is an appropriate way to handle operations. To be clear, **[BEGIN HIGHLY CONFIDENTIAL INFORMATION]** [redacted] **[END HIGHLY CONFIDENTIAL INFORMATION]** The benefit of having an owned mine with no minimum take is to allow PacifiCorp the flexibility to respond to market conditions, and we expect

PacifiCorp to take advantage of that flexibility as appropriate given its reclamation obligations.

Finally, Sierra Club argues that the Jim Bridger Long Term Fuel Plan should be filed annually rather than biannually. We disagree that conditions are so volatile as to require annual updates and instead direct PacifiCorp to continue filing the biannual Long Term Fuel Plan with its IRP—that is, at the front end of the IRP process.

VII. ORDER

1. The Stipulation between PacifiCorp, dba Pacific Power; Staff of the Public Utility Commission of Oregon; the Oregon Citizens' Utility Board; Calpine Energy Solutions, LLC; Klamath Water Users Association; and Vitesse, LLC, attached as Appendix A, is adopted.

2. Advice No. 23-008 is permanently suspended.

3. PacifiCorp, dba Pacific Power, must update its net power costs to reflect the changes adopted in this order to establish its Transition Adjustment Mechanism net power costs for calendar year 2024 and file its tariffs to be effective January 1, 2024.

Made, entered, and effective Oct 27, 2023.

Megan W. Decker Chair	**Letha Tawney** Commissioner

A party may request rehearing or reconsideration of this order under ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-001-0720. A copy of the request must also be served on each party to the proceedings as provided in OAR 860-001-0180(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480 through 183.484.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 420

In the Matter of PACIFICORP, d/b/a PACIFIC POWER, 2024 Transition Adjustment Mechanism	**STIPULATION**

The TAM is an annual filing by PacifiCorp d/b/a Pacific Power (PacifiCorp or Company) to update its net power costs (NPC) in rates and set the transition adjustments for direct access customers. This Stipulation resolves all issues in the 2024 Transition Adjustment Mechanism (TAM) among the stipulating parties, with one exception: the treatment of Washington Cap and Invest program costs in the 2024 TAM.

PARTIES

1. The parties to this Stipulation are PacifiCorp, Staff of the Public Utility Commission of Oregon (Commission) (Staff), the Oregon Citizens' Utility Board (CUB), Calpine Energy Solutions, LLC (Calpine Solutions), Klamath Water Users Association (KWUA), and Vitesse, LLC (Vitesse) (collectively, the Stipulating Parties). Sierra Club and the Alliance of Western Energy Consumers (AWEC) are not parties to this Stipulation.[1]

[1] Sierra Club proposed several coal-related adjustments in the 2024 TAM. Non-Company Stipulating Parties do not take a position on Sierra Club's coal recommendations.

BACKGROUND

2. On April 3, 2023, PacifiCorp filed its 2024 TAM with direct testimony and exhibits from Ramon Mitchell, James Owen, and Judith Ridenour. PacifiCorp also filed revised tariff sheets for Schedule 201 to implement the 2024 TAM.

3. PacifiCorp's 2024 TAM filing proposed updates to NPC in rates and test period forecasts for: (1) incremental benefits related to the Company's participation in the energy imbalance market (EIM); and (2) renewable energy production tax credits (PTC).

4. PacifiCorp's April 3, 2023 TAM filing (Initial Filing) reflected total-company NPC for the test period (the 12 months ending December 31, 2024) of approximately $2.642 billion. NPC in the Initial Filing were approximately $754.7 million on an Oregon-allocated basis. This amount was approximately $255.1 million higher than the $499.6 million Oregon-allocated NPC from the Final Update in the 2023 TAM (Docket No. UE 400), and $163.8 million higher when adjusted for forecasted load changes and PTCs. The Initial Filing reflected an overall average rate increase of approximately 9.5 percent.

5. On April 4, 2023, AWEC filed to intervene in this proceeding. On April 6, 2023, Calpine Solutions filed a petition to intervene. On April 11, 2023, Sierra Club filed a petition to intervene. On April 12, 2023, CUB filed a Notice of Intervention. On April 21, 2023, Vitesse filed a petition to intervene. On May 5, 2023, KWUA filed a petition to intervene. On April 24, 2023, Administrative Law Judge Katharine Mapes held a prehearing conference and subsequently issued a Prehearing Conference Memorandum granting certain requested interventions and adopting a procedural schedule.

Administrative Law Judge Katharine Mapes also issued rulings on April 17, 2023 and May 11, 2023 granting the other requested interventions.

6. On June 23, 2023, Staff, AWEC, CUB, Sierra Club, Vitesse, and Calpine Solutions filed opening testimony.

7. On July 24, 2023, PacifiCorp filed reply testimony from Ramon Mitchell, James Owen, Zepure Shahumyan, and Matthew McVee, along with an updated NPC forecast (Reply Update). The Reply Update reflected total-company NPC for the test period (the 12 months ending December 31, 2024) of approximately $2.527 billion. On an Oregon-allocated basis, NPC in the Reply Update were approximately $722.1 million. This amount was approximately $222.5 million higher than the $499.6 million Oregon allocated NPC from the 2023 TAM Final Update, and $130.8 million higher when adjusted for forecasted load changes and PTCs.

8. On August 16, 2023, Staff and intervenors filed rebuttal testimony. Two weeks later, on August 30, 2023, PacifiCorp filed surrebuttal testimony from Ramon Mitchell, James Owen, Matthew McVee, Ryan Fuller, and Michael Wilding. In that testimony, the Company indicated that it would remove costs associated with the Ozone Transport Rule (OTR) from the 2024 TAM, for a $19 million decrease in total company NPC, or $5.5 million in Oregon-allocated NPC.

9. The parties convened settlement conferences on August 11, 21, and 28, 2023. All parties initially engaged in the settlement discussions, although AWEC and Sierra Club ultimately ceased their participation. At a final settlement conference on September 6, 2023, the Stipulating Parties reached a settlement in principle that resolved all issues among the Stipulating Parties, except the treatment of Washington Cap and

Invest program costs. The Stipulating Parties informed the Commission of this settlement at the start of the hearing in this case on September 7, 2023.

10. The settlement establishes baseline 2024 NPC in rates, subject to the Final Update. The terms of the settlement are captured in this Stipulation.

AGREEMENT

11. Overall Agreement: The Stipulating Parties agree to submit this Stipulation to the Commission and request that the Commission approve the Stipulation as presented. The Stipulating Parties agree that the rate change resulting from the Stipulation, including the resolution of the remaining unsettled issue, results in rates that are fair, just, and reasonable, as required by ORS 756.040.[2] The Stipulation results in a decrease to the Reply Update of approximately $18.5 million on an Oregon-allocated basis, consisting of the removal of OTR costs ($5.5 million Oregon-allocated), as discussed in the Company's surrebuttal testimony and in Paragraph 13, and a $13 million Oregon-allocated, unspecified adjustment to NPC, as described in Paragraph 18. The Stipulation results in a total company NPC baseline of $2.463 billion and an Oregon-allocated NPC baseline of $703.6 million, subject to the Final Update. This reflects an overall average rate increase of approximately $112.3 million, subject to the Final Update, when adjusted for forecasted load changes and PTCs as shown in Exhibit 1; or 6.5 percent as shown in Exhibit 2.

12. TAM Adjustments and Updates: The Stipulating Parties agree that PacifiCorp will file a Final Update to its 2024 TAM filing consistent with the TAM

[2] Sierra Club proposed several coal-related adjustments in the 2024 TAM. Non-Company Stipulating Parties do not take a position on Sierra Club's coal recommendations, or whether resolution of Sierra Club's recommendations result in rates that are fair, just, and reasonable.

Guidelines, including the adjustments described in this Stipulation. The Stipulating Parties recognize that the estimated impact of the agreed-upon adjustments may change in the TAM Final Update, along with the NPC baseline and overall rate change.

13. Ozone Transport Rule (OTR): PacifiCorp will remove the modeling impacts of the OTR on the Company's generation, which is approximately $5.5 million Oregon-allocated, in the 2024 TAM Final Update. In the event that PacifiCorp is required to implement the OTR in 2024 and the costs of OTR implementation exceed $5.5 million on an Oregon-allocated basis, the Company will file a deferral to capture these costs. The Stipulating Parties agree not to oppose PacifiCorp's deferral. The Stipulating Parties may contest the amortization of any costs included in the deferral in the proceeding in which PacifiCorp seeks to amortize the deferral.

14. Technical Workshops: PacifiCorp agrees to hold the following technical workshops. To this end, the intent of the participants in the workshop is to identify, specify, and describe the modeling, inputs, and forecasting of the topics identified below. As part of PacifiCorp's participation in the workshops, PacifiCorp will provide workshop attendees standalone descriptions of how these topics are modeled in Aurora or outside of the NPC model. The Stipulating Parties reserve the right to object to the Company's approach to these issues in the 2025 TAM, including but not limited to the purpose of the Company's modeling adjustments.

a. Coal Contracting
b. Coal Dispatch
c. Day-Ahead and Real-Time (DA/RT) Adjustment
d. Wind Forecasting
e. Short-Term Transmission
f. Extended Day-Ahead Market/EIM

15. Coal Reporting: PacifiCorp will work with Staff to provide the following information in the 2023 Power Cost Adjustment Mechanism (PCAM) filing regarding the operation of PacifiCorp's coal facilities. The Stipulating Parties will meet prior to the filing of the 2026 TAM to discuss if the reporting should be modified and continued for subsequent years.

a. Generation per plant
   i. Forecasted in the previous TAM
   ii. Actual
   iii. Variance

b. Amount of coal consumed per plant
   i. Forecasted in the previous TAM
   ii. Actual
   iii. Variance

c. Price of coal consumed for the month at each plant
   i. Forecasted in the previous TAM;
   ii. Actual; and
   iii. Variance.

d. PacifiCorp will provide a report comparing the monthly actual generation against the forecasted generation for each coal facility, and provide an explanation for each variance in coal generation greater than 10 percent when compared to the forecast. This report will also compare the annual forecasted coal price for each facility in the TAM against the actuals provided in the PCAM. For each variance greater than 10 percent, PacifiCorp will provide an explanation of the variance.

16. PCAM: The Company agrees to work with the Stipulating Parties on the rate effective date of revised Schedule 206 in the 2022 PCAM, Docket No. UE 421, to minimize the impact on customers during the 2023-2024 winter heating season. PacifiCorp agrees that if the combined January 1, 2024 rate increase for residential customers from the 2024 TAM, 2022 PCAM, the Renewable Adjustment Clause rate change, and any other rate change exceeds 15 percent, PacifiCorp will seek to delay the

rate effective date of revised Schedule 206, the PCAM tariff, until April 1, to keep the rate increase to residential customers below 15 percent.

17. DA/RT Adjustment in the Calculation of the Transition Charge: In calculating the transition adjustment for direct access, PacifiCorp will apply the DA/RT adjustment for the market prices used for valuing changes in generation[3] for months when the net change in the Company's generation is a reduction of generation attributable to direct access. For months in which there is a net increase in PacifiCorp generation attributable to direct access, PacifiCorp will not apply the market adjustment to the net generation increase, but rather PacifiCorp will value it at cost. PacifiCorp will continue to apply the DA/RT adjustment to changes in sales and purchases.

18. Unspecified Monetary Adjustment: For the sole purpose of settling the Stipulating Parties' NPC adjustments in the 2024 TAM, PacifiCorp agrees to reduce Oregon-allocated NPC through an unspecified monetary adjustment of $13.0 million.

19. Washington Cap and Invest: The treatment of Washington Cap and Invest program in PacifiCorp's 2024 TAM is excluded from this Stipulation and will remain a contested issue in this proceeding.

20. Other Adjustments: Any adjustment to PacifiCorp's Initial or Reply Filing not incorporated into this Stipulation directly or by reference is resolved among the Stipulating Parties without an adjustment or recommendation for the purposes of this proceeding, except for the Washington Cap and Invest issue identified in Paragraph 19. This stipulation allows for the settlement of this case without agreement of parties on the methodology for issues raised by the Stipulating Parties, including but not limited to

[3] PAC/100, Mitchell/44, line 17 – PAC/100, Mitchell/45, line 10.

market caps, and the day-ahead/real-time price adder. Approval of the Stipulation does not represent the Commission adopting any parties' methodologies for those adjustments. The issues raised by Sierra Club are not resolved by this Stipulation; however, the non-PacifiCorp Stipulating Parties agree to take no position on the Sierra Club issues.

21. Entire Agreement: The Stipulating Parties agree that this Stipulation represents a compromise among competing interests and a resolution of the contested issues raised by the Stipulating Parties in this proceeding. Any other adjustment to PacifiCorp's Initial Filing or Reply Update previously recommended by any Stipulating Party but not incorporated into this Stipulation directly or by reference is resolved without an adjustment for the purposes of this proceeding.

22. This Stipulation will be offered into the record of this proceeding as evidence pursuant to OAR 860-001-0350(7). The Stipulating Parties agree to support this Stipulation throughout this proceeding and any appeal, provide witnesses to sponsor this Stipulation at the hearing, and recommend that the Commission issue an order adopting the settlements contained herein. The Stipulating Parties also agree to cooperate in drafting and submitting joint testimony or a brief in support of the Stipulation in accordance with OAR 860-001-0350(7)(a).

23. If this Stipulation is challenged, the Stipulating Parties agree that they will continue to support the Commission's adoption of the terms of this Stipulation. The Stipulating Parties agree to cooperate in any hearing and put on such a case as they deem appropriate to respond fully to the issues presented, which may include raising issues that are incorporated in the settlements embodied in this Stipulation.

24. The Stipulating Parties have negotiated this Stipulation as an integrated document. If the Commission rejects all or any material part of this Stipulation or adds any material condition to any final order that is not consistent with this Stipulation, each Stipulating Party reserves its right, pursuant to OAR 860-001-0350(9), to present evidence and argument on the record in support of the Stipulation or to withdraw from the Stipulation. The Stipulating Parties agree that in the event the Commission rejects all or any material part of this Stipulation or adds any material condition to any final order that is not consistent with this Stipulation, the Stipulating Parties will meet in good faith within 15 days and discuss next steps. A Stipulating Party may withdraw from the Stipulation after this meeting by providing written notice to the Commission and other Stipulating Parties. The Stipulating Parties shall be entitled to seek rehearing or reconsideration pursuant to OAR 860-001-0720 in any manner that is consistent with the agreement embodied in this Stipulation.

25. By entering into this Stipulation, no Stipulating Party shall be deemed to have approved, admitted, or consented to the facts, principles, methods, or theories employed by any other Stipulating Party in arriving at the terms of this Stipulation, other than those specifically identified in the body of this Stipulation. No Stipulating Party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding, except as specifically identified in this Stipulation.

26. The Stipulating Parties agree to make best efforts: (1) to provide each other any and all news releases that any Stipulating Party intends to make about the Stipulation two business days in advance of publication, and (2) to include in any news release or

announcement a statement that the Staff's recommendation to approve the settlement is not binding on the Commission itself.

27. This Stipulation is not enforceable by any Stipulating Party unless and until adopted by the Commission in a final order. Each signatory to this Stipulation acknowledges that they are signing this Stipulation in good faith and that they intend to abide by the terms of this Stipulation unless and until the Stipulation is rejected or adopted only in part by the Commission. The Stipulating Parties agree that the Commission has exclusive jurisdiction to enforce or modify the Stipulation.

28. This Stipulation may be executed in counterparts and each signed counterpart shall constitute an original document.

STAFF

By: */s/ Stephanie Andrus*

Date: 9/12/2023

PACIFICORP

By: ______________________

Date: ______________________

VITESSE, LLC

By: ______________________

Date: ______________________

OREGON CITIZENS' UTILITY BOARD

By: ______________________

Date: ______________________

CALPINE ENERGY SOLUTIONS LLC

By: ______________________

Date: ______________________

KLAMATH WATER USERS ASSOCIATION

By: ______________________

Date: ______________________

STAFF

By: ______________________________

Date:______________________________

PACIFICORP

/s/ Matthew McVee
By: ______________________________

Date: 9/12/2023______________________

VITESSE, LLC

By: ______________________________

Date: ____________________________

OREGON CITIZENS' UTILITY BOARD

By: ______________________________

Date:_____________________________

CALPINE ENERGY SOLUTIONS LLC

By: ______________________________

Date:______________________________

KLAMATH WATER USERS ASSOCIATION

By: ______________________________

Date:_____________________________

STAFF	**PACIFICORP**
By: ______________________________	By: ______________________________
Date:______________________________	Date:______________________________
VITESSE, LLC	**OREGON CITIZENS' UTILITY BOARD**
By: */s/ Irion Sanger*	By: ______________________________
Date: 9/12/2023	Date:______________________________
CALPINE ENERGY SOLUTIONS LLC	**KLAMATH WATER USERS ASSOCIATION**
By: ______________________________	By: ______________________________
Date:______________________________	Date:______________________________

STAFF	**PACIFICORP**
By: ______________________	By: ______________________
Date:______________________	Date:______________________
VITESSE, LLC	**OREGON CITIZENS' UTILITY BOARD**
By: ______________________	By: */s/ Michael Goetz*_______________
Date:______________________	Date: 9/12/2023____________________
CALPINE ENERGY SOLUTIONS LLC	**KLAMATH WATER USERS ASSOCIATION**
By: ______________________	By: ______________________
Date:______________________	Date:______________________

STAFF

By: ______________________________

Date: ______________________________

PACIFICORP

By: ______________________________

Date: ______________________________

VITESSE, LLC

By: ______________________________

Date: ______________________________

OREGON CITIZENS' UTILITY BOARD

By: ______________________________

Date: ______________________________

CALPINE ENERGY SOLUTIONS LLC

By: ______________________________

Date: 9-12-23

KLAMATH WATER USERS ASSOCIATION

By: ______________________________

Date: ______________________________

STAFF

By: ________________________________

Date:________________________________

PACIFICORP

By: ________________________________

Date:________________________________

VITESSE, LLC

By: ________________________________

Date:________________________________

OREGON CITIZENS' UTILITY BOARD

By: ________________________________

Date:________________________________

CALPINE ENERGY SOLUTIONS LLC

By: ________________________________

Date:________________________________

KLAMATH WATER USERS ASSOCIATION

By: __*/s/ Paul Simmons*______________

Date:_ 9/12/2023________________________

Docket UE 420

Exhibit 1

to

Stipulation

PacifiCorp
CY 2024 TAM
Reply Filing

			Total Company							Oregon Allocated			
Line no		ACCT.	UE-400 CY 2023 - Final Filing	TAM CY 2024 - Initial Filing	TAM CY 2024 - Reply Filing	TAM CY 2024 - Settlement	Factor	Factors CY 2023	Factors CY 2024	UE-400 CY 2023 - Final Filing	TAM CY 2024 - Initial Filing	TAM CY 2024 - Reply Filing	TAM CY 2024 - Settlement
1	**Sales for Resale**												
2	Existing Firm PPL	447	6,381,695	-	-	-	SG	26.002%	28.701%	1,659,353	-	-	-
3	Existing Firm UPL	447	-	-	-	-	SG	26.002%	28.701%	-	-	-	-
4	Post-Merger Firm	447	556,906,202	426,328,887	416,041,280	416,041,280	SG	26.002%	28.701%	144,805,420	122,362,385	119,409,697	119,409,697
5	Non-Firm	447	-	-	-	-	SE	24.920%	28.515%	-	-	-	-
6	**Total Sales for Resale**		563,287,897	426,328,887	416,041,280	416,041,280				146,464,773	122,362,385	119,409,697	119,409,697
7													
8	**Purchased Power**												
9	Existing Firm Demand PPL	555	59,530,582	22,795,100	27,788,625	27,788,625	SG	26.002%	28.701%	15,479,000	6,542,514	7,975,726	7,975,726
10	Existing Firm Demand UPL	555	9,126,863	9,531,665	9,200,052	9,200,052	SG	26.002%	28.701%	2,373,145	2,735,722	2,640,544	2,640,544
11	Existing Firm Energy	555	171,504,893	71,888,724	86,683,767	86,683,767	SE	24.920%	28.515%	42,739,259	20,499,156	24,717,980	24,717,980
12	Post-merger Firm	555	1,094,540,292	1,389,718,118	1,317,590,013	1,317,590,013	SG	26.002%	28.701%	284,599,752	398,868,641	378,166,860	378,166,860
13	Secondary Purchases	555	-	-	-	-	SE	24.920%	28.515%	-	-	-	-
14	Other Generation Expense	555	-	-	-	-	SG	26.002%	28.701%	-	-	-	-
15	**Total Purchased Power**		1,334,702,630	1,493,933,607	1,441,262,456	1,441,262,456				345,191,156	428,646,032	413,501,110	413,501,110
16													
17	**Wheeling Expense**												
18	Existing Firm PPL	565	23,886,724	22,898,000	19,834,453	19,834,453	SG	26.002%	28.701%	6,210,969	6,572,048	5,692,767	5,692,767
19	Existing Firm UPL	565	-	-	-	-	SG	26.002%	28.701%	-	-	-	-
20	Post-merger Firm	565	124,541,723	134,214,173	138,790,535	138,790,535	SG	26.002%	28.701%	32,383,041	38,521,355	39,834,835	39,834,835
21	Non-Firm	565	6,893,033	9,027,449	10,923,881	10,923,881	SE	24.920%	28.515%	1,717,753	2,574,188	3,114,958	3,114,958
22	**Total Wheeling Expense**		155,321,479	166,139,622	169,548,868	169,548,868				40,311,763	47,667,591	48,642,559	48,642,559
23													
24	**Fuel Expense**												
25	Fuel Consumed - Coal	501	635,260,287	547,388,163	538,341,964	538,341,964	SE	24.920%	28.515%	158,307,751	156,088,389	153,508,855	153,508,855
26	Fuel Consumed - Coal (Cholla)	501	-	-	-	-	SE	24.920%	28.515%	-	-	-	-
27	Fuel Consumed - Gas	501	19,326,688	156,802,484	132,206,683	132,206,683	SE	24.920%	28.515%	4,816,238	44,712,416	37,698,894	37,698,894
28	Natural Gas Consumed	547	396,871,314	692,508,768	637,993,977	637,993,977	SE	24.920%	28.515%	98,900,886	197,469,703	181,924,745	181,924,745
29	Simple Cycle Comb. Turbines	547	13,620,689	7,592,963	20,076,862	20,076,862	SE	24.920%	28.515%	3,394,295	2,165,143	5,724,941	5,724,941
30	Steam from Other Sources	503	4,484,106	4,440,902	4,440,902	4,440,902	SE	24.920%	28.515%	1,117,446	1,266,329	1,266,329	1,266,329
31	**Total Fuel Expense**		1,069,563,084	1,408,733,280	1,333,060,389	1,333,060,389				266,536,615	401,701,979	380,123,763	380,123,763
32													
33	TAM Settlement Adjustment*		(18,844,704)	-	-	(64,456,772)			-	(4,900,000)	-	-	(18,500,000)
34													
35	**Net Power Cost (Per Aurora)**		1,977,454,591	2,642,477,623	2,527,830,433	2,463,373,661				500,674,760	755,653,217	722,857,736	704,357,736
36													
37	Oregon Situs NPC Adustments		(1,091,313)	(905,561)	(762,508)	(762,508)	OR	100.000%	100.000%	(1,091,313)	(905,561)	(762,508)	(762,508)
38	**Total NPC Net of Adjustments**		1,976,363,278	2,641,572,061	2,527,067,926	2,462,611,153				499,583,447	754,747,655	722,095,228	703,595,228
39													
40	Production Tax Credit (PTC)		(279,202,594)	(280,883,910)	(281,434,085)	(281,434,085)	SG	26.002%	28.701%	(72,597,592)	(80,617,632)	(80,775,540)	(80,775,540)
41	**Total TAM Net of Adjustments**		1,697,160,684	2,360,688,151	2,245,633,841	2,181,177,069				426,985,855	674,130,023	641,319,688	622,819,688
42													
43										Increase Absent Load Change	247,144,168	214,333,833	195,833,833
44													
45									Oregon-allocated NPC (incl. PTC) Baseline in Rates from UE-400	426,985,855			
46									$ Change due to load variance from UE-400 forecast	$83,509,234			
47									2024 Recovery of NPC (incl. PTC) in Rates	$510,495,090			
48													
49										**Increase Including Load Change**	**$ 163,634,934**	**$ 130,824,599**	**$ 112,324,599**
50													
51										Add Other Revenue Change	-	-	-
52													
53										**Total TAM Increase/(Decrease)**	**$ 163,634,934**	**$ 130,824,599**	**$ 112,324,599**

Docket UE 420

Exhibit 2

to

Stipulation

PACIFIC POWER
ESTIMATED EFFECT OF PROPOSED PRICE CHANGE
ON REVENUES FROM ELECTRIC SALES TO ULTIMATE CONSUMERS
DISTRIBUTED BY RATE SCHEDULES IN OREGON
FORECAST 12 MONTHS ENDED DECEMBER 31, 2024

					Present Revenues ($000)			Proposed Revenues ($000)			Change				
											Base Rates		Net Rates		
Line No.	Description	Sch No.	No. of Cust	MWh	Base Rates	Adders[1]	Net Rates	Base Rates	Adders[1]	Net Rates	($000)	%[2]	($000)	%[2]	Line No.
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	
							(5) + (6)			(8) + (9)	(8) - (5)	(11)/(5)	(10) - (7)	(13)/(7)	
	Residential														
1	Residential	4	540,041	5,829,081	$737,548	$8,977	$746,525	$779,459	$8,977	$788,436	$41,911	5.7%	$41,911	5.6%	1
2	**Total Residential**		540,041	5,829,081	$737,548	$8,977	$746,525	$779,459	$8,977	$788,436	$41,911	5.7%	$41,911	5.6%	2
	Commercial & Industrial														
3	Gen. Svc. < 31 kW	23	85,313	1,166,351	$149,483	$2,496	$151,978	$157,386	$2,496	$159,882	$7,904	5.3%	$7,904	5.2%	3
4	Gen. Svc. 31 - 200 kW	28	10,587	2,084,027	$186,116	$20,590	$206,706	$200,055	$20,590	$220,645	$13,938	7.5%	$13,938	6.7%	4
5	Gen. Svc. 201 - 999 kW	30	872	1,325,081	$105,890	$12,417	$118,307	$114,580	$12,417	$126,997	$8,690	8.2%	$8,690	7.4%	5
6	Large General Service >= 1,000 kW	48	182	6,123,426	$435,177	$16,877	$452,053	$473,256	$16,877	$490,132	$38,079	8.7%	$38,079	8.4%	6
7	Partial Req. Svc. >= 1,000 kW	47	6	32,263	$4,320	$88	$4,409	$4,511	$88	$4,600	$191	8.7%	$191	8.4%	7
8	Dist. Only Lg Gen Svc >= 1,000 kW	848	1	0	$1,219	$111	$1,329	$1,219	$111	$1,329	$0	0.0%	$0	0.0%	8
9	Agricultural Pumping Service	41	7,913	237,644	$30,384	($2,916)	$27,468	$31,919	($2,916)	$29,003	$1,535	5.1%	$1,535	5.6%	9
10	**Total Commercial & Industrial**		104,874	10,968,792	$912,589	$49,663	$962,251	$982,927	$49,663	$1,032,589	$70,338	7.7%	$70,338	7.3%	10
	Lighting														
11	Outdoor Area Lighting Service	15	5,703	8,050	$788	$242	$1,031	$807	$242	$1,049	$18	2.3%	$18	1.8%	11
12	Street Lighting Service Comp. Owned	51	1,121	21,063	$2,715	$933	$3,648	$2,770	$933	$3,703	$56	2.1%	$56	1.5%	12
13	Street Lighting Service Cust. Owned	53	292	7,519	$392	$221	$613	$409	$221	$630	$17	4.3%	$17	2.8%	13
14	Recreational Field Lighting	54	100	1,394	$88	$52	$140	$91	$52	$143	$3	3.6%	$3	2.3%	14
15	**Total Public Street Lighting**		7,215	38,026	$3,983	$1,448	$5,431	$4,077	$1,448	$5,525	$94	2.4%	$94	1.7%	15
16	**Subtotal**		652,131	16,835,899	$1,654,120	$60,087	$1,714,207	$1,766,463	$60,087	$1,826,550	$112,343	6.8%	$112,343	6.6%	16
17	Emplolyee Discount		*975*	*13,481*	($419)	($5)	($424)	($443)	($5)	($449)	($24)		($24)		17
17	Paperless Credit				($2,072)		($2,072)	($2,072)		($2,072)	$0		$0		17
18	AGA Revenue				$3,521		$3,521	$3,521		$3,521	$0		$0		18
19	COOC Amortization				$1,767		$1,767	$1,767		$1,767	$0		$0		19
20	**Total Sales with AGA**		652,131	16,835,899	$1,656,916	$60,082	$1,716,998	$1,769,235	$60,082	$1,829,317	$112,319	6.8%	$112,319	6.5%	20

[1] Excludes effects of the Low Income Bill Payment Assistance Fund (Sch. 91), Low Income Discount Cost Recovery Adjustment (Sch. 92), BPA Credit (Sch. 98), Public Purpose Charge (Sch. 290) and System Benefits Charge (Sch. 291).
[2] Percentages shown for Schedules 48 and 47 reflect the combined rate change for both schedules