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September 22, 2023

VIA ELECTRONIC FILING

Attention: Filing Center
Public Utility Commission of Oregon
201 High Street SE, Suite 100
Salem, Oregon 97308-1088

Re: UE 420 – *In the Matter of PACIFICORP, dba PACIFIC POWER, 2024 Transition Adjustment Mechanism.*

Attention Filing Center:

Attached for filing in the above-referenced docket is PacifiCorp dba Pacific Power's Opening Brief. Confidential material in support of this filing has been provided to parties under Order No. 16-128. Highly confidential material in support of this filing has been provided to parties under Order No. 23-211.

Please contact this office with any questions.

Sincerely,

Adam Lowney

Attachment

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 420

In the Matter of

PACIFICORP d/b/a PACIFIC POWER,

2024 Transition Adjustment Mechanism.

PACIFICORP'S OPENING BRIEF

Redacted

September 22, 2023

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I. INTRODUCTION

In accordance with the Scheduling Memorandum issued by Administrative Law Judge Katharine Mapes on September 8, 2023, PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company) submits this Opening Brief in the 2024 Transition Adjustment Mechanism (TAM) addressing two sets of issues unresolved by the Stipulation filed on September 12, 2023. Consistent with the terms of the Stipulation and Scheduling Memorandum, this brief addresses the appropriate treatment of costs resulting from the Washington Cap and Invest Program created by the Climate Commitment Act (CCA) and Sierra Club's coal-related adjustments and recommendations.

The Public Utility Commission of Oregon (Commission) should approve recovery of the compliance costs imposed by the Washington Cap and Invest Program without imputing the value of no-cost allowances that PacifiCorp is required by law to allocate exclusively to Washington customers. PacifiCorp's recommended treatment of these costs is consistent with fundamental ratemaking principles, the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol (2020 Protocol), Washington law, and sound regulatory policy, which should not penalize utilities for complying with state law.

As for Sierra Club's adjustments, the Commission should approve recovery of:

- Costs under the Company's Hunter/Gentry coal supply agreement (CSA). Despite difficult market conditions, the Company was able to secure the cost-effective Hunter/Gentry CSA through a robust request for proposals (RFP) process consistent with the requirements set in previous TAM orders. The Company has demonstrated that this CSA is necessary to meet forecast generation demand at the Hunter plant and provides substantial customer benefits.
- Costs associated with the Preferred Scenario to fuel the Jim Bridger plant under the Company's 2023 Long-Term Fuel Supply Plan (2023 Fuel Plan). The Preferred Scenario provides over [redacted] in added customer benefits on a total-company

basis present value of revenue requirement, as compared to Scenario 4 for which Sierra Club advocates.

- Reject Sierra Club's recommendation to convert the long-term fuel plan process for the Jim Bridger plant, which is now synced to the two-year cycle of PacifiCorp's Integrated Resource Plan (IRP), into an annual filing.

II. WASHINGTON CAP AND INVEST PROGRAM

The Washington Cap and Invest Program impacts the Company in two separate and distinct ways. First, the Cap and Invest Program imposes an obligation on PacifiCorp to acquire greenhouse gas (GHG) emission allowances for generation from the Chehalis gas-fired generation plant (Chehalis).[1] These generally applicable compliance costs are tied to *generation* and are imposed on all generating facilities located in Washington state.[2] Second, PacifiCorp is allocated a certain number of no-cost allowances based on the Company's *retail load* in Washington.[3] These no cost allowances are provided only to utilities subject to Washington's Clean Energy Transformation Act (CETA)[4] and are calculated based on the Company's load and CETA-compliant resources that will be used to serve that load.[5] Washington law requires that the Company allocate the benefits of the no-cost allowances exclusively to Washington customers.[6]

Here, Staff recommends the Commission disallow $1.65 million by imputing all the value of the no-cost allowances that would have been allocated to Oregon if the law did not require allocation exclusively to Washington or disallow $825,000 by imputing 50 percent of the

[1] PAC/600, Shahumyan/3.
[2] RCW 70A.65.080(1)(b).
[3] RCW 70A.65.120(1).
[4] RCW 70A.65.120(1).
[5] WAC 173-446-230(2)(a)-(b).
[6] *See* RCW 70A.65.010(21) (defining "cost burden" to mean "the impact on rates or charges to customers of electric utilities *in Washington state* for the incremental cost of electricity service to serve load due to the compliance cost for greenhouse gas emissions caused by the program") (emphasis added).

no-cost allowances.[7] As an alternative recommendation—raised for the first time in an errata filing after the submission of the Company's surrebuttal testimony—Staff recommends a $21 million disallowance by removing *all* Cap and Invest Program compliance costs from the TAM, a recommendation that is shared by the Alliance of Western Energy Consumers (AWEC).[8] Even with the Cap and Invest Program compliance costs included, Chehalis reduces net power costs (NPC) by $37 million—meaning that Staff and AWEC recommend keeping all the customer benefits of Chehalis, while removing the environmental compliance costs incurred to generate those benefits. Vitesse does not object to including Cap and Invest Program costs in the TAM but recommends an adjustment to how the Cap and Invest Program compliance costs are modeled.[9]

The Commission should reject Staff's and AWEC's recommendations because they deviate from the well-established ratemaking principles, are contrary to the Commission-approved 2020 Protocol, and would set a troubling precedent penalizing compliance with Washington law and undermining Oregon's own environmental policy. To understand why it is appropriate for Oregon customers to pay for the benefits received from the Chehalis plant, the Company, *first*, outlines the applicable legal framework for the Cap and Invest Program; *second*, explains that the generally applicable compliance costs associated with allowances for Chehalis generation are appropriately allocated to all PacifiCorp customers, including Oregon; *third*, explains that the no-cost allowances are appropriately situs assigned to Washington, consistent with Washington law; *fourth*, explains that potential legal challenges to the Cap and Invest Program are no basis to deny cost recovery in this case; and *fifth*, addresses Vitesse's modeling adjustment.

[7] Staff/1000, Anderson/16-17. These amounts, like all values cited in the brief, are Oregon-allocated unless otherwise specified.
[8] Staff's Errata to Rebuttal Testimony (Staff/1000, Anderson/17); AWEC/100, Mullins/14.
[9] Vitesse/100, Johnson/24.

A. Background

1. The Washington CCA created a generally applicable obligation for PacifiCorp to acquire emission allowances for the Chehalis plant.

The Washington CCA establishes regulatory requirements to reduce GHG emissions from generating plants located in Washington.[10] One component of the CCA, the Cap and Invest Program, attempts to reduce GHG emissions by establishing a market incentive for covered entities to reduce emissions.[11] Generally, the Cap and Invest Program establishes a "cap" on the amount of emissions that are permitted in the state,[12] which will decrease annually to meet GHG emission reduction goals.[13] The Washington Department of Ecology (Ecology) then distributes emission allowances to covered entities, which function as financial instruments that the covered entities may trade to meet their own emission needs.[14] An allowance is required for each metric ton of carbon dioxide equivalent that the covered entity emits.[15]

PacifiCorp is a "covered entity" subject to the Cap and Invest Program because it owns and operates Chehalis, which is an electricity-generating facility in Washington state with associated emissions of at least 25,000 metric tons of carbon dioxide equivalent.[16] The Cap and Invest Program requires that the Company demonstrate compliance by retiring GHG allowances for any GHG emissions from Chehalis—even if the Company exports the energy outside the

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[10] PAC/600, Shahumyan/2-3.
[11] PAC/600, Shahumyan/2.
[12] RCW 70A.65.070(2) ("The annual allowance budgets must be set to achieve the share of reductions by covered entities necessary to achieve the 2030, 2040, and 2050 statewide emissions limits established in RCW 70A.45.020[.]").
[13] RCW 70A.65.060(1) ("In order to ensure that greenhouse gas emissions are reduced by covered entities consistent with the limits established in RCW 70A.45.020, the department must implement a cap on greenhouse gas emissions from covered entities and a program to track, verify, and enforce compliance through the use of compliance instruments."); RCW 70A.45.020(1)(a), (a)(iv) ("The state shall limit anthropogenic emissions of greenhouse gases to achieve the following emission reductions for Washington state . . . By 2050, reduce overall emissions of greenhouse gases in the state to five million metric tons, or ninety-five percent below 1990 levels.").
[14] RCW 70A.65.060(2)(c), (h) ("The program must consist of . . . Distribution of emission allowances, as provided in RCW 70A.65.100, and through the allowance price containment provisions under RCW 70A.65.140 and 70A.65.150; . . . [and] Providing for the transfer of allowances and recognition of compliance instruments, including those issued by jurisdictions with which Washington has linkage agreements[.]").
[15] *See* RCW 70A.65.010(1) ("'Allowance' means an authorization to emit up to one metric ton of carbon dioxide equivalent.").
[16] RCW 70A.65.080(1)(b), (c); PAC/600, Shahumyan/3.

state of Washington.[17] For energy from Chehalis allocated to serve customers outside of Washington there is an associated GHG obligation proportionate to the cost-allocation share of Chehalis.[18]

2. Washington issues no-cost allowances for Washington customers of utilities subject to the CETA.

While the requirement to obtain GHG allowances is tied directly to *generation* located in Washington, the Company also receives no-cost allowances tied directly to *retail load* located in Washington. In particular, utilities like PacifiCorp that serve Washington customers *and are subject to CETA*—a separate Washington statute[19]—receive no-cost allowances that can be used to demonstrate compliance with the Cap and Invest Program.[20] These no-cost allowances are not directly correlated to the emissions from a utility's generation within the state of Washington. Rather, to receive no-cost allowances a utility must be subject to CETA and the amount of no-cost allowances a utility receives is based on forecasts of the utility's Washington retail load and CETA-compliant resource mix used to serve the Washington retail load.[21] These no-cost allowances are intended to "mitigate the cost burden" to "customers of electric utilities in Washington state" that are subject to CETA.[22] The plain language of the statute states that utilities subject to CETA must pass the benefits of these no-cost allowances to their Washington

[17] PAC/600, Shahumyan/3.
[18] PAC/600, Shahumyan/3.
[19] RCW 19.405.030(1)(a); RCW 19.405.050(1); RCW 19.405.010(2) ("It is the policy of the state to eliminate coal-fired electricity, transition the state's electricity supply to one hundred percent carbon-neutral by 2030, and one hundred percent carbon-free by 2045.").
[20] RCW 70A.65.120(1).
[21] WAC 173-446-230(2)(a)-(b). These forecasts are approved by the Washington Utilities and Transportation Commission and are "derived from sources that most accurately and best predict how each [investor-owned utility] will comply *with CETA*[.]"; *In the Matter of the Petition of PacifiCorp dba Pacific Power & Light Company, Requesting Approval of Forecasts under RCW 70A.65.120*, WUTC Docket No. UE-220789, Order No. 01 at 1-2 (Jan. 24, 2023) (emphasis added).
[22] RCW 70A.65.120(1) ("The legislature intends by this section to allow all consumer-owned electric utilities and investor-owned electric utilities subject to the requirements of chapter 19.405 RCW, the Washington clean energy transformation act, to be eligible for allowance allocation as provided in this section in order to mitigate the cost burden of the program on electricity customers."); RCW 70A.65.010(21) ("'Cost burden' means the impact on rates or charges to customers of electric utilities in Washington state for the incremental cost of electricity service to serve load due to the compliance cost for greenhouse gas emissions caused by the program.").

customers. The Washington Department of Ecology confirmed this interpretation,[23] rejecting PacifiCorp's comments proposing that it be allowed to allocate no-cost allowances to its non-Washington customers.[24]

B. Oregon customers should pay their share of the Cap and Invest Program compliance costs for Chehalis.

1. Chehalis provides significant customer benefits even with the additional compliance costs.

"In ratemaking, utilities and regulators strive to allocate costs according to causation . . . [t]he cost-causation principle compares 'the costs assessed against a party to the . . . benefits drawn by that party.'"[25] Here, Chehalis generation provides significant benefits to Oregon customers, even with the additional GHG compliance costs, and therefore Oregon customers should pay for the costs of Chehalis generation.[26] Without Chehalis, forecast NPC increases by $131 million total-company, or $37 million Oregon-allocated.[27] PacifiCorp's Cap and Invest Program compliance costs are $73 million on a total-company basis, or $20.4 million Oregon-allocated.[28] Therefore, even accounting for the Cap and Invest Program compliance costs, generation from Chehalis results in substantial net benefits for Oregon customers.

Neither AWEC nor Staff dispute these significant benefits or present any evidence that Oregon customers are better off without Chehalis. Yet, AWEC's primary recommendation and Staff's alternative recommendation is that the Commission disallow recovery of *all* GHG compliance costs in Oregon.[29] These recommendations would have Oregon customers taking the

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[23] 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) (last visited Sept. 11, 2023).
[24] PAC/600, Shahumyan/5.
[25] *In the Matter of J.M.G. v. PacifiCorp, dba Pacific Power*, Docket No. UCR 191, Order No. 18-430, 2018 Or. PUC Lexis 434 at *10 (Nov. 5, 2018) (quoting *S.C. Pub. Serv. Auth. v. FERC*, 762 F3d 41, 48 (DC Cir 2014)); *see also* Jonathan A. Lesser, Ph.D. & Leonardo R. Giacchino, Ph.D., *Fundamentals of Energy Regulation* at 183 (2d ed., Public Utilities Reports, Inc. 2013) ("One fundamental regulatory principle is to allocate costs to those who cause them.").
[26] PAC/1000, McVee/3.
[27] PAC/800, Mitchell/74.
[28] PAC/100, Mitchell/21.
[29] Staff's Errata to Rebuttal Testimony, Staff/1000, Anderson/17; AWEC/100, Mullins/14.

significant benefits of a plant without paying the attendant costs, in violation of well-established cost causation principles.[30]

2. Disallowing recovery of Cap and Invest Program costs penalizes the Company's compliance with Washington law and undermines Oregon environmental policy.

There is no dispute that the Company is required to comply with Washington law, including the obligation to acquire necessary GHG allowances under the Cap and Invest Program. By recommending a total disallowance of compliance costs, Staff and AWEC would have PacifiCorp bear the burden of compliance with Washington law, while Oregon customers reap the benefits.[31] Shifting compliance costs to the Company sets poor precedent by creating a disallowance for compliance with state law.

Moreover, by penalizing the Company for complying with Washington law and incentivizing non-compliance, Staff's and AWEC's recommendation is directly contrary to Oregon state policies seeking to reduce GHG emissions. In House Bill (HB) 2021, the Oregon Legislature stated that "existing and future electricity markets will play a critical role in the transformation of the electric sector to nonemitting sources"[32] and, acknowledging the role of markets, Oregon "should coordinate and collaborate with other states" to align accounting methods in these markets.[33] Given that Washington and Oregon emissions reduction policies are aligned,[34] encouraging non-compliance with Washington's law undermines the effectiveness of Oregon's law and could risk retaliatory measures.

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[30] Order No. 18-430 at *10; PAC/1000, McVee/3.
[31] PAC/1000, McVee/6-7.
[32] HB 2021, 2021 Reg. Legis. Session § 15(1)(a) (June 26, 2021).
[33] *Id*. at § 15(1)(c).
[34] Evidentiary Hearing Transcript 27:10-15 (Sept. 7, 2023) [hereinafter "Evid. Tr."].

3. Chehalis's compliance costs are appropriately allocated to Oregon under the 2020 Protocol.

The Commission-approved 2020 Protocol governs the allocation of costs to Oregon customers.[35] Generation-related dispatch costs and generation and fuel-related taxes are allocated to customers as system costs—meaning that Oregon pays its share of the costs commensurate with its share of all other generation-related costs, consistent with basic principles of cost-causation.[36] Here, the Cap and Invest Program requires PacifiCorp to secure an allowance for each metric ton of carbon dioxide equivalent emitted from Chehalis and therefore the allowance costs are directly tied to the level of generation at the plant.[37] Therefore, for purposes of cost allocation under the 2020 Protocol, the costs of these allowances required under the Cap and Invest Program are generation-related dispatch costs or generation taxes—which are allocated to Oregon customers.[38] In this way, the generation-related tax imposed by the CCA is treated the same as the wind tax imposed by Wyoming.[39]

AWEC agrees that the Cap and Invest Program compliance costs are a "generation tax"[40] and therefore appears to concede that its recommendation is inconsistent with the Commission-approved 2020 Protocol. On that basis alone, AWEC's recommendation should be rejected.

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[35] *See In the Matter of PacifiCorp, dba Pacific Power, Request to Initiate an Investigation of Multi-Jurisdictional Issues and Approve an Inter-Jurisdictional Cost Allocation Protocol*, Docket No. UM 1050, Order No. 20-024 at 2 (Jan. 23, 2020); Docket No. UM 1050, Order No. 23-229, App'x A at 2 (June 30, 2023).

[36] Evid. Tr. 18:10-15; PAC/1316 at 13-14 of 134 ("**3.1.7 Miscellaneous Costs and Taxes** . . . Generation-related dispatch costs and associated plant will be allocated on the SG factor. . . . Generation and fuel-related taxes will be allocated using the SG Factor."); Docket No. UM 1050, Order No. 17-124 at 4 (Mar. 29, 2017) (extending approval of the 2017 Protocol "to allow the continued development of the" 2020 Protocol while also requiring an Oregon-specific investigation into allocation and cost-causation principles).

[37] PAC/600, Shahumyan/3; PAC/400, Mitchell/91 ("The costs associated with the Washington Cap and Invest Program represent incremental and actual costs of generating at the Chehalis plant[.]"); PAC/1000, McVee/5 ("[T]here is no compliance obligation if there is no generation and the amount of the compliance obligation is determined by the amount of generation.").

[38] Evid. Tr. 18:15-20; PAC/1316 at 13-14 (Section 3.1.7).

[39] Wyo. Stat. § 39-22-103; PAC/1000, McVee/5.

[40] AWEC/100, Mullins/13 ("[T]he Washington CCA . . . is also an order of magnitude greater than generation taxes imposed by other states, such as the $1.00/MWh Wyoming wind tax[.]"); *see also* AWEC/100 at Mullins/12 (Q. Is it reasonable for Oregon customers to pay these [Cap and Invest Program] costs? A. No. Complex legal issues arise with respect to the imposition of generation taxes and regulations that impact interstate commerce.").

Staff argues that the Cap and Invest Program compliance costs are not a generation tax because according to Staff, Washington has described the Cap and Invest Program as duplicative of CETA, which Staff argues "is not a tax."[41] Staff does not dispute, however, that the level of GHG compliance costs are directly tied to the level of generation at Chehalis—meaning that even if the compliance costs are not a "tax" they are undisputedly a "generation-related dispatch cost," which is system allocated just like generation-related taxes.[42] Staff's argument therefore at best points out a distinction without difference for purposes of cost allocation under the 2020 Protocol.

a. *<u>Staff's reliance on Section 5.8 of the 2020 Protocol is misplaced.</u>*

Staff relies on Section 5.8 of the 2020 Protocol to assert that "the costs of the CCA should be allocated and assigned on a situs basis to [Washington] until the CCA is examined by the [Multi-State Process] workgroup and consensus is reached on the appropriate allocation. Absent that, the appropriate allocation would be determined in the negotiation of the next Protocol."[43] Staff's argument, however, misunderstands the 2020 Protocol.

First, Section 5.8 of the 2020 Protocol is not binding and has not been approved for setting rates.[44] Section 5.8 of the 2020 Protocol applies to the "Post Interim Period," which will begin when the 2020 Protocol ends and a replacement protocol is adopted by the Commission.[45] The Commission just extended the 2020 Protocol for two more years and the replacement protocol has not been adopted.[46] Therefore, the Commission has not approved Section 5.8 for

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[41] PAC/1310 at 6.
[42] Evid. Tr. 18:12-20; PAC/1316 at 13-14 (Section 3.1.7).
[43] PAC/1310 at 6.
[44] Evid. Tr. 16:16-20 ("Section 5.8 is . . . not applicable to setting rates in 2024 or allocating costs of the Washington cap-and-invest program.").
[45] Evid. Tr. 16:6-10; *see also* PAC/1316 at 35 (Section 5: "As stated in Section 2, these Resolved Issues [addressed in Section 5] of the 2020 Protocol are intended to take effect with the implementation of the Post-Interim Period Method.").
[46] Order No. 23-229 at 1.

setting rates in Oregon and Section 5.8 is irrelevant to allocating costs of the Washington Cap and Invest Program.[47]

Second, Staff's only stated rationale for removing all GHG compliance costs from Oregon rates is the last sentence in Section 5.8, which states, "As new issues arise, PacifiCorp will bring each issue to the MSP Workgroup to discuss whether each issue is a State-specific initiative, and, if not, whether a different allocation method is appropriate."[48] Staff argues that because PacifiCorp has not brought the Washington Cap and Invest Program to the MSP workgroup, as contemplated by Section 5.8, the costs of the Washington Cap and Invest Program should be removed from Oregon rates until there is consensus on an appropriate allocation.[49] However, the operative sections of the 2020 Protocol that apply to the 2024 TAM do not have this same requirement.[50] Therefore, Staff has provided no basis in the 2020 Protocol for its new adjustment denying recovery of emission compliance costs for the Chehalis plant.[51]

Third, even though Section 5.8 is inapplicable, its language supports the view that system allocation of the Cap and Invest Program compliance costs is the current standard under the 2020 Protocol. When describing state-specific initiatives that are situs assigned, Section 5.8 itself states, "Historically, these [state-specific initiatives] . . . have not included local fees or taxes related to the ongoing operation of existing transmission and generation facilities within a State."[52] The Cap and Invest Program clearly applies to the ongoing operation of an existing generation facility within Washington and is appropriately characterized as a tax and therefore even Staff's reliance on Section 5.8 undermines its recommendation to situs assign the Cap and Invest Program compliance costs to Washington.

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[47] Evid. Tr. 16:16-20 ("[S]ection 5.8 may never apply depending on the terms of the methodology that replaces the 2020 Protocol.").
[48] PAC/1316 at 40-41 of 134 (Section 5.8).
[49] PAC/1310 at 6 of 11.
[50] Evid. Tr. 20:13-21; PAC/1316 at 13-14 (Section 3.1.7).
[51] Evid. Tr. 20:13-21.
[52] PAC/1316 at 40.

Moreover, Cap and Invest Program Costs are unlike costs that are situs-assigned under the applicable section of the 2020 Protocol, which include demand response programs, resources acquired to comply with a state's portfolio standards, incentive programs, net-metering tariffs, capacity standard programs, solar subscription programs, electric vehicle programs, and acquisition of renewable energy certificates.[53]

b. *Staff's argument that the CCA is duplicative of CETA is unpersuasive.*

Staff also argues the Cap and Invest Program compliance costs are "duplicative" of CETA, and because CETA is situs-assigned, the costs of the Cap and Invest Program should be situs assigned too.[54] This argument is unpersuasive because incremental CETA compliance costs are situs-assigned to Washington customers and not paid by Oregon customers.[55] Even accepting Staff's premise that the laws are "duplicative," Oregon customers are not paying duplicative costs. Moreover, the fact CETA compliance costs are situs assigned to Washington supports situs allocation of the no-cost allowances, which are received by PacifiCorp only because it is subject to CETA, as discussed below.

4. Oregon customers regularly pay environmental compliance costs imposed by other states and the Cap and Invest Program is no different.

The environmental compliance costs resulting from the Washington Cap and Invest Program are substantively the same as other environmental compliance costs imposed by states on generation facilities located within the state.[56] Oregon customers routinely pay for environmental compliance costs imposed by other states and the GHG allowance costs should be treated no different.[57] For example, Oregon rates include: costs imposed by Washington for fish passage investments at the Merwin dam located in Washington;[58] costs imposed by Utah for

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[53] PAC/1316 at 11-12 (Section 3.1.2.1).
[54] PAC/1310 at 5-6.
[55] Evid. Tr. 19:23-20:3.
[56] PAC/1000, McVee/3.
[57] PAC/1000, McVee/3-4.
[58] *See e.g. In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 374, Order No. 20-473 at 3 (Dec. 18, 2020).

emission control equipment on Utah generation facilities;[59] costs imposed by Wyoming for emission control equipment on Wyoming generation facilities;[60] costs imposed by Utah for environmental reclamation of the Deer Creek mine;[61] costs imposed by Wyoming for environmental reclamation of the Bridger Coal Company (BCC) mine;[62] and costs imposed by Wyoming for wind generation from Wyoming wind plants.[63] Similarly, customers in other states routinely pay environmental compliance costs imposed by Oregon on facilities located in this state, such as the Portland Harbor remediation costs and costs associated with environmental remediation of retired manufactured gas plants.[64]

Oregon customers also pay the costs and receive the benefits of PacifiCorp's participation in a similar emission-based Cap and Trade Program created by California.[65] There is no rational basis to treat the Washington Cap and Invest Program any different from the California Cap and Trade Program.[66]

Adopting Staff's and AWEC's recommendation to remove *all* the Cap and Invest Program compliance costs notwithstanding the NPC benefits Oregon customers receive from Chehalis generation would set a poor precedent for other existing and future environmental compliance costs imposed by other states on generating resources located in those states. If Oregon policy becomes one where Oregon customers pay only for costs imposed by the state of

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[59] *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 246, Order No. 12-493 at 27 (Dec. 20, 2012).
[60] Order No. 20-473 at 81.
[61] Order No. 20-473 at 88.
[62] Highly Confidential Evidentiary Hearing Transcript 57:1-15 (Sept. 8, 2023) [hereinafter "Highly Confidential Evid. Tr."].
[63] *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision, et al.*, Docket No. UE 399, Order No. 22-491, App'x B at 2 (Dec. 16, 2022).
[64] PAC/1000, McVee/3-4; *see, e.g.*, *In the Matter of Northwest Natural Gas Company, dba NW Natural, Mechanism for Recovery of Environmental Remediation Costs*, Docket No. UM 1635, Order No. 15-049 at 6 (Feb. 20, 2015) (authorizing recovery of prudently incurred environmental remediation costs and allocating those costs between Oregon and Washington based on the historic operations of the facilities to serve both states).
[65] *In the Matter of PacifiCorp, dba Pacific Power, 2021 Transition Adjustment Mechanism*, Docket No. UE 375, Order No. 20-392 at 6 (Oct. 30, 2020).
[66] Order No. 20-392 at 6 (addressing issue regarding calculation of GHG benefits resulting from California program); PAC/1000, McVee/6 (discussing similarities between California cap and trade program and Washington's Cap and Invest Program).

Oregon, then it will become very difficult for the Company to serve Oregon customers with resources located in other states, like Wyoming wind facilities or Utah solar facilities. Other states could similarly respond in-kind and situs-assign Oregon's environmental policies that impact a system resource located in Oregon, such as the Hermiston generating facility.

5. AWEC's position here is contrary to its position in Portland General Electric Company's (PGE) Annual Update Tariff (AUT) case.

In this case, AWEC recommends removing from the TAM all costs relating to compliance with the Cap and Invest Program.[67] AWEC argues that the Cap and Invest Program creates "complex legal issues" and "is discriminatory towards Oregon ratepayers[.]"[68] However, in PGE's AUT case, AWEC raised no such challenges to the legality of the Cap and Invest Program.[69] In fact, in that case AWEC argued the Commission should impute customer benefits from the same Cap and Invest Program AWEC argues here illegally discriminates against Oregon.[70] AWEC provided no explanation for its divergent positions and its contradictory positions undermine the credibility of its recommendation in this case.

6. PacifiCorp's inclusion of Cap and Invest Program compliance costs in Federal Energy Regulatory Commission (FERC) Account 547 is not improper.

AWEC claims that PacifiCorp improperly included the cost of Cap and Invest Program allowances in FERC Account 547- Fuel and that those allowances instead "must be expensed to FERC Account 509 – Allowances[.]"[71] AWEC further asserts that PacifiCorp's inclusion of Cap and Invest Program allowances in the TAM was "improper accounting" because the Company "has not proposed any modification to the TAM to include FERC Account 509 in NPC."[72]

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67 AWEC/100, Mullins/14.
68 AWEC/100, Mullins/12.
69 PAC/1304 at 16-20.
70 PAC/1304 at 17.
71 AWEC/200, Mullins/35-36.
72 AWEC/200, Mullins/36.

However, while FERC Account 509 has long existed as an account for sulfur dioxide allowances issued under the federal Clean Air Act Amendments of 1990,[73] FERC only recently adopted a rule that may require PacifiCorp to expense other allowances, such as allowances required under the Cap and Invest Program, to FERC Account 509.[74] Importantly, that rule will not take effect until January 1, 2025,[75] and therefore does not impact this 2024 TAM.

Moreover, regardless of how Cap and Invest Program allowances are treated in the Company's FERC accounts, PacifiCorp's dispatch decisions relating to Chehalis will take into account the added costs of Cap and Invest Program compliance allowances.[76] Therefore, to ensure accuracy in NPC modeling, PacifiCorp must include the cost of these allowances.

C. The no-cost allowances issued to PacifiCorp are appropriately allocated exclusively to Washington customers.

1. PacifiCorp receives no-cost allowances because it is subject to CETA.

No-cost allowances are provided only to utilities that serve Washington customers and are subject to compliance with CETA,[77] a separate Washington law that is distinct from the Cap and Invest Program.[78] The amount of no-cost allowances is determined based on the Company's Washington retail load and the CETA-compliant resources that will be used to serve that load.[79] This contrasts with the separate and distinct generation-based GHG compliance requirements applicable to Chehalis.

[73] 18 CFR Part 101, General Instructions (21)(E).
[74] *Accounting and Reporting Treatment of Certain Renewable Energy Assets*, 183 FERC ¶ 61,205, Order No. 898 (2023).
[75] *Id.*
[76] PAC/800, Mitchell/73.
[77] RCW 70A.65.120(1).
[78] RCW 19.405.030(1)(a).
[79] WAC 173-446-230(2)(a)-(b). These forecasts are approved by the Washington Utilities and Transportation Commission and are "derived from sources that most accurately and best predict how each [investor-owned utility] will comply *with CETA*[.]" WUTC Docket No. UE-220789, Order No. 01 at 2.

2. CETA is a state-specific initiative that is situs-assigned to Washington under the 2020 Protocol.

All incremental costs of CETA compliance are situs-assigned to Washington under the 2020 Protocol as costs associated with a state-specific initiative.[80] This means that any incremental costs associated with resources acquired to comply with CETA are situs-assigned to Washington and the situs assigned resources are then used to determine the amount of no-cost allowances PacifiCorp receives.[81] Because the no-cost allowances result from CETA compliance obligations paid for by Washington customers, the no-cost allowances are a benefit of a state-specific initiative and therefore must be situs-assigned to customers in Washington.

Taken together with the discussion of the *generation-related* compliance costs discussed above, the 2020 Protocol requires system allocation of the dispatch-related costs imposed by the Cap and Invest Program. But the *load-related* no-cost allowances are situs assigned to Washington, just as CETA compliance costs are situs assigned to Washington.

3. Staff's recommendation to assign benefits from the no-cost allocations to Oregon customers is contrary to Washington law.

No-cost allocations are intended to benefit "customers of electric utilities in Washington state"[82] and Ecology has issued direction specifying that the benefits of the no-cost allowances are intended to be "passed on to customers in the State of Washington."[83] Staff acknowledges this direction from Ecology,[84] but nonetheless asserts that Oregon customers should also receive benefits from these no-cost allocations.[85] Staff therefore recommends that Oregon customers should receive either a full share of the allowances that would be allocated to Oregon if they were system assigned or receive 50 percent of the no-cost allowances Oregon customers would

[80] Evid. Tr. 19:23-24.
[81] PAC/1000, McVee/5.
[82] RCW 70A.65.010(21).
[83] PAC/600, Shahumyan/5 (quoting WAC Climate Commitment Act Program, (Sept. 2022), (available at: https://apps.ecology.wa.gov/publications/documents/2202046.pdf) (last visited Sept. 11, 2023)).
[84] Staff/1000, Anderson/16.
[85] Staff/1000, Anderson/16.

otherwise be allocated.[86] Like Staff's recommendation to disallow recovery of *all* Cap and Trade Program compliance costs, Staff's recommendation to allocate no-cost allowances to Oregon would penalize the Company for complying with Washington law and allow Oregon customers to take the full benefits of Chehalis—$37 million in reduced NPC—without paying the costs necessary to generate those benefits.

At the hearing, a question arose regarding the allocation of potential revenues that could be earned by exporting emission-free generation to Washington wholesale customers and whether it would be equitable to allocate a portion of that revenue to Washington customers if Washington customers receive the benefits of no-cost allowances.[87] As an initial matter, there is nothing in the record to suggest that these benefits will materialize in 2024. Moreover, if the Company earns a premium for the sale of emission-free generation at Mid-Columbia as a result of the market impacts of the Cap and Invest Program, the sale of that emission-free generation will come from a system resource that is presumably paid for by all customers, including Washington customers. If Washington customers pay for a resource and that resource produces emission-free energy that generates revenue, then it is reasonable for Washington customers to receive the benefits of that revenue consistent with their allocation of the costs of that resource.

D. Constitutional challenges to the no-cost allowances issued to utilities subject to CETA are immaterial to the issues in this proceeding.

AWEC's testimony suggests they intend to challenge the constitutionality of Washington's no-cost allowances under the Dormant Commerce Clause.[88] However, that argument would be outside the scope of this case. While parties in a pending federal lawsuit have raised similar challenges, the court has not issued a stay or otherwise limited application of the

[86] Staff/1000, Anderson/16-17.
[87] Evid. Tr. 27:10-15.
[88] *See* AWEC/100, Mullins/12 ("Complex legal issues arise with respect to the imposition of generation taxes and regulations that impact interstate commerce. Such legal issues will not be addressed here. They will be reserved for legal briefing. Based upon the advice of counsel, however, the facts support a conclusion that the Washington CCA, as applied to interstate generators such as Chehalis, is discriminatory towards Oregon ratepayers, and therefore, is not a permissible cost to include in the TAM.").

Cap and Invest Program during the pending litigation.[89] Unless and until the court stays or overturns the CCA, PacifiCorp must comply with the law. PacifiCorp will incur costs in 2024 to comply with the Cap and Invest Program, and the Company should be authorized to recover those costs regardless of whether the program is eventually determined to be unconstitutional.[90] To the extent that AWEC is asking this Commission to determine that a Washington law is unconstitutional, this would not excuse PacifiCorp's compliance obligations under that law, and such a request is far beyond the scope of the TAM.

E. Vitesse's adjustments to modeling Cap and Invest Program costs would increase NPC without improving the accuracy of NPC forecast.

PacifiCorp models Cap and Invest Program compliance costs using an incremental price per megawatt-hour (MWh) for all output from Chehalis.[91] Vitesse has argued that the Company should instead apply a variable rate to account for the variation of the emissions intensity over the output range of Chehalis.[92] Vitesse further asserted that the Company should adopt this change in its dispatch modeling to reflect the operational cost of Chehalis.[93]

As Vitesse acknowledges,[94] this proposal would increase the Company's NPC by $1.42 million on an Oregon-allocated basis.[95] Moreover, Vitesse's proposal would not increase the accuracy of PacifiCorp's NPC modeling. While PacifiCorp currently models the Cap and Invest Program costs using a static cost per MWh, Vitesse's proposal would instead involve inputting a static emissions rate.[96] Calculating either static rate would require measuring aggregate pounds of emissions over an extended period of time and dividing by the aggregate

[89] *Invenergy Thermal LLC v. Watson*, Case No. 3:22-cv-5967-BHS, Complaint at 4-5 (WD Wash Dec. 13, 2022). The State of Washington has moved to dismiss the case, the plaintiff has responded to that motion, and the defendant has filed a reply to the plaintiff's response. However, the court has not yet ruled on the state's motion.
[90] PAC/100, Mitchell/21. For the purposes of this proceeding, PacifiCorp takes no position on the constitutionality of the Cap and Invest Program or the no-cost allocations issued to the Company as a utility subject to CETA.
[91] PAC/100, Mitchell/20.
[92] Vitesse/100, Johnson/24.
[93] Vitesse/200, Johnson/29.
[94] Vitesse/200, Johnson/29.
[95] PAC/800, Mitchell/75.
[96] PAC/800, Mitchell/75.

amount of fuel consumed over that same period.[97] Either method would result in embedding historical fuel usage into the forecast of future fuel usage.[98] Because the Company's internal optimization models use a fuel adder to model the impact on system dispatch resulting from the Washington Cap and Invest Program, Vitesse's proposed approach for modeling Cap and Invest Program costs would not be more accurate than the approach PacifiCorp currently uses.[99] Vitesse's proposed adjustment to the Company's modeling should be rejected for these reasons.

III. SIERRA CLUB ADJUSTMENTS

A. The Hunter/Gentry coal supply agreement is prudent.

In this year's TAM, the Company included three new CSAs with a total amount of [redacted] tons for the Hunter plant located in Emery County, Utah. Under these CSAs, the Company has obtained the following coal volumes for 2024: [redacted] tons under the Hunter/Wolverine CSA, [redacted] tons under the Hunter/Bronco CSA, and [redacted] tons under the Hunter/Gentry CSA.

Sierra Club challenges the prudence of only the smallest of these CSAs, the Hunter/Gentry CSA. Sierra Club proposes to disallow the costs of this CSA, which totals [redacted] or [redacted] Oregon-allocated.[100] Sierra Club's disallowance does not account for the cost of replacement generation, however, which would likely be higher cost than Hunter generation. Thus, PacifiCorp expects the disallowance of the Hunter/Gentry CSA would increase NPC, undermining Sierra Club's argument that this CSA is not beneficial to customers.[101] In addition, it is not clear whether Sierra Club is still pursuing this adjustment because Sierra Club's

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[97] PAC/800, Mitchell/75.
[98] PAC/800, Mitchell/75.
[99] PAC/800, Mitchell/75.
[100] Sierra Club claims that, based on use of an outdated price, PacifiCorp is actually seeking [redacted] or [redacted] Oregon-allocated for costs related to the Hunter/Gentry CSA. Sierra Club seeks to disallow this higher amount. Sierra Club/100, Burgess and Roumpani/41. The Company corrected the Hunter/Gentry CSA price in the Reply Update, so the 2024 TAM now reflects Hunter/Gentry CSA costs of [redacted]. Sierra Club does not dispute this fact in its rebuttal testimony.
[101] Sierra Club/100, Burgess and Roumpani/2.

rebuttal testimony failed to address the adjustment or contest PacifiCorp's reply evidence in any way. Thus, for the most part, PacifiCorp's record on this issue is undisputed.

The Company executed the Hunter/Gentry CSA on January 20, 2023.[102] The Hunter/Gentry CSA runs from [redacted], and provides [redacted] tons of coal per annum for the years [redacted].[103] [redacted][104] The Hunter/Gentry CSA is prudent, beneficial to customers, and necessary to meet the Company's generation demand in 2024.

When evaluating the prudence of a utility the Commission examines whether the utility's decision was reasonable "in light of the circumstances existing at the time [the utility] entered into the contract[]."[105] The prudence standard is objective and "review[s] the reasonableness of the [utility's] actions based on information that was available or could reasonably have been available at the time of the action."[106] Because of the "need for regulatory certainty," the Commission "must exercise a high degree of caution" in assessing prudence.[107] In the context of CSAs, the Commission "consider[s] not just the decision made by the utility, but also the decision-making process used to reach that decision."[108]

The Commission has outlined a framework for review of new CSAs in the TAM. In the 2021 TAM, docket UE 375, the Commission approved a stipulation in which the Company agreed to provide testimony in its Initial Filing on "the prudence of any coal supply agreements that were entered into since the previous year's reply testimony."[109] In the 2022 TAM, docket

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[102] PAC/200, Owen/15.
[103] PAC/500, Owen/6. This CSA provided [redacted] tons of coal in 2023 and will provide [redacted] tons in both 2024 and 2025.
[104] PAC/201, Owen/1.
[105] *In the Matter of Portland General Electric Company, Application for Annual Adjustment to Schedule 125 under the terms of the Res. Valuation Mechanism*, Docket No. UE 139, Order No. 02-772 at 11 (Oct. 30, 2002).
[106] Order No. 02-772 at 11.
[107] Order No. 02-772 at 11.
[108] *In the Matter of PacifiCorp, dba Pacific Power, 2022 Transition Adjustment Mechanism*, Docket No. UE 390, Order No. 21-379 at 19 (Nov. 1, 2021).
[109] Order No. 20-392 at 4.

UE 390, the Commission outlined the CSA information and analysis that the Company should include in its Initial Filing, including information about the underlying generation forecast, consistency with IRP planning and plant retirement targets, cost forecasts, and CSA flexibility.[110] The following year, in the 2023 TAM, docket UE 400, the Commission gave specific instruction for new Hunter CSAs, directing the Company to provide an analysis of "how additional flexibility in the Utah coal plants could be achieved in order to deliver the customer benefits."[111] The Company complied with these requirements in the 2024 TAM, providing information in its Initial Filing on each new CSA since the 2023 TAM.[112] The Company's report and economic analysis of the Hunter/Gentry CSA was filed as Exhibit PAC/201.

1. The prudence of the Hunter/Gentry CSA must be evaluated in the context of the difficult conditions prevailing in the Utah coal market.

Since the third quarter of 2021, coal markets have become increasingly volatile and coal prices have risen steeply.[113] Increased coal demand due to high domestic natural gas prices, low inventories at coal mines and coal-fired power plants, increased demand abroad for coal exports, international and domestic supply chain constraints, labor and material shortages, and general market inflation are all factors affecting the price and availability of coal for the year 2024 and beyond.[114] Worldwide, coal prices have reacted to the natural gas market, which has similarly seen increasingly high prices by constricted supply exacerbated by the Russian invasion of Ukraine.[115] Customers who would typically purchase and use natural gas have turned to coal, resulting in coal suppliers raising prices in response to rising demand.

The Utah coal market has experienced particularly difficult conditions since 2022.[116] As of summer 2023, Utah coal prices remain approximately double in comparison with the 2021

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[110] Order No. 21-379 at 6–7.
[111] *In the Matter of PacifiCorp d/b/a Pacific Power, 2023 Transition Adjustment Mechanism*, Docket No. UE 400, Order No. 22-389 at 6 (Oct. 25, 2022).
[112] PAC/200, Owen/12–18.
[113] PAC/200, Owen/3.
[114] PAC/200, Owen/3.
[115] PAC/500, Owen/9.
[116] PAC/500, Owen/10.

levels.[117] The increased demand for coal worldwide has opened doors for suppliers to access a larger, more competitive market.[118] Suppliers are relying less on historical relationships with the Company and instead turning to the highest paying customer, leaving the Company with fewer purchase opportunities and diminished negotiating power at the CSA bargaining table.[119] Utah coal production was severely disrupted due to a fire at the Lila Canyon mine in September 2022, resulting in the mine's indefinite closure.[120] As a result, the mine has still not resumed operations as of September 2023. Such closure resulted in one of the Company's suppliers serving its Hunter and Huntington plants, Wolverine Fuel Sales, LLC (Wolverine), raising force majeure claims for coal supplied by the Lila Canyon mine.[121] The Company's coal supply issues at Hunter were compounded when another supplier, Bronco Utah Operations, LLC (Bronco), made a separate force majeure claim.[122] These coal supply constraints have resulted in lower than forecasted coal deliveries at the Hunter and Huntington plants in late 2022 and 2023,[123] leading to a depletion of the Company's coal stockpiles that had to be used to meet demand.[124]

2. The Hunter/Gentry CSA resulted from a competitive bidding process, demonstrating its reasonableness.

The Company issued an RFP in the fall of 2022, requesting bids for up to [redacted] and up to [redacted].[125] The RFP was similar in design to the Company's past coal RFPs, which are consistent with the Commission requirements and have consistently produced prudent and reasonable CSAs.[126] [redacted]

[117] PAC/500, Owen/10.
[118] PAC/200, Owen/7.
[119] PAC/200, Owen/7.
[120] PAC/500, Owen/10.
[121] PAC/500, Owen/12–13.
[122] PAC/500, Owen/12.
[123] PAC/200, Owen/6.
[124] PAC/200, Owen/6.
[125] PAC/900, Owen/10.
[126] PAC/900, Owen/10-11.
[127] PAC/201, Owen/5; *see also* Highly Conf. Evid. Tr. 12:3-6 (Owen testimony that the Company has "[redacted]").

[redacted] Some coal suppliers provided multiple bids to be considered as alternatives. For example, the Company received two separate but alternative bids from [redacted], Bids 7 and 8, where the Company could choose only one of the two bids—but not both—due to the suppliers' own constraints.[129] The Company ultimately selected Bid 8, foreclosing the Company's ability to also select Bid 7. As a result, the Company selected the next best choice, Bid 1, which resulted in the Hunter/Gentry CSA.[130]

[redacted]

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[128] PAC/201, Owen/1.
[129] PAC/500, Owen/20.
[130] PAC/500, Owen/20.
[131] PAC/201, Owen/6.
[132] PAC/201, Owen/6.
[133] PAC/500, Owen/22.
[134] PAC/201, Owen/9.
[135] PAC/201, Owen/9.
[136] PAC/201, Owen/10.

[redacted]

These new terms give the Company increased flexibility and responds directly to Commission guidance in previous TAM orders.

The Hunter/Gentry CSA resulted from a comprehensive analysis of bids received in response to PacifiCorp's RFP, and the CSA is supported by detailed economic analysis.[142] All CSAs executed by PacifiCorp support the reliability of the Company's power supply by ensuring that there is sufficient fuel to operate a coal-fired power plant when needed to serve customers. In particular, the fixed pricing and reasonable term provisions in PacifiCorp's CSAs have insulated the Company and its customers from significant exposure to market fluctuations.[143] Given the need for a reliable fuel supply, PacifiCorp's goal is to secure the least-cost, least-risk fuel supply for customers. [redacted]

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[137] PAC/201, Owen/5.
[138] Highly Conf. Evid. Tr. 62:5-12.
[139] Highly Conf. Evid. Tr. 62:12-21.
[140] Highly Conf. Evid. Tr. 62:22-25, 63:1-7.
[141] Highly Conf. Evid. Tr. 63:7-9.
[142] Order No. 21-379 at 6-7; Order No. 22-389 at 5.
[143] PAC/200, Owen/3.

[redacted] The Hunter/Gentry CSA is one of the many examples of PacifiCorp achieving this goal.

3. Sierra Club's proposed disallowance relies on faulty assumptions as to the coal forecast and a misunderstanding of the available RFP bids.

Sierra Club contends that "inflated demand" led to the Hunter/Gentry CSA and the Company's evaluation of the bids received in response to the RFP was not comprehensive.[145] These contentions are inaccurate.

First, Sierra Club argues that the Company's assumed demand for Hunter generation "far exceeds the demand in the TAM analysis or the average cost run results" and concludes that this "inflated demand" led the Company to enter into the Hunter/Gentry CSA when there was no actual need for an additional contract.[146] However, Sierra Club improperly conflates the TAM analysis and the PLEXOS modeling that led to the demand determination.[147] The Hunter coal demand that is reflected in the TAM is limited to the expected coal supply available during 2024—which is less than either the amounts under contract or the full volumes PacifiCorp would need to satisfy the true demand for Hunter generation.[148] The Company uses the Aurora modeling software to prepare the assumed coal demand in the TAM, separate and distinct from the PLEXOS modeling software, used to determine the Hunter plant's coal supply needs.[149] The PLEXOS modeling is consistent with the Company's IRP and was prepared in advance of the TAM, using a separate official forward price curve, distinct OTR cost assumptions, and different system resources.[150] Sierra Club's reliance on the forecast generation in the TAM to discount the Company's separate analysis of its coal supply needs ignores the fact that PacifiCorp is facing supply shortfalls and depleted coal stockpiles at Hunter in 2024, even with the Hunter/Gentry

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[144] Highly Conf. Evid. Tr. 8:11-15.
[145] Sierra Club/100, Burgess and Roumpani/37.
[146] Sierra Club/100, Burgess and Roumpani/37.
[147] PAC/500, Owen/21.
[148] PAC/500, Owen/21.
[149] PAC/500, Owen/21.
[150] PAC/500, Owen/21.

CSA. [redacted] Sierra Club's argument to the contrary has no merit.

Second, Sierra Club argues that the Company did not comprehensively model the RFP bids.[152] Sierra Club maintains that if the Company had performed a comprehensive analysis of every bid it received, it would have selected a lower cost bid, Bid 7.[153] The Company did analyze and select multiple bids in response to the September 2022 RFP. Sierra Club neglects to acknowledge that the Company also selected Bid 8, resulting in a CSA with [redacted] for the Hunter plant.[154] Notably, the selection of Bid 8 foreclosed the Company's ability to select Sierra Club's preferred bid, Bid 7.[155] Sierra Club does not address this fundamental flaw in its argument; similarly, Sierra Club does not take issue with the CSA entered as a result of selecting Bid 8.[156] [redacted]

Finally, Sierra Club generally maintains that the Hunter/Gentry CSA does not benefit customers.[158] But the Company's economic analysis shows [redacted] in quantifiable benefits from the Hunter/Gentry CSA.[159] Sierra Club does not rebut the Company's analyses and does not demonstrate that the Hunter/Gentry CSA was imprudent or unreasonable.

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[151] PAC/201, Owen/1.
[152] Sierra Club/100, Burgess and Roumpani/37.
[153] Sierra Club/100, Burgess and Roumpani/40.
[154] PAC/500, Owen/20.
[155] PAC/500, Owen/20.
[156] Sierra Club/100, Burgess and Roumpani/40.
[157] PAC/201, Owen/6-8.
[158] Sierra Club/100, Burgess and Roumpani/37.
[159] PAC/201, Owen/1.

B. The Company evaluated and selected prudent fueling scenarios in line with the Jim Bridger 2023 Fuel Plan.

The 2023 Fuel Plan is an analysis of the best options for supplying the Company's Jim Bridger plant.[160] The Company prepared its 2023 Fuel Plan to assess and identify fueling options for the Jim Bridger plant, including pricing assumptions and mine plan options developed as a basis for the 2023 IRP.[161] [redacted] To develop the 2023 Fuel Plan, and in accordance with past practice, the Company studied, reviewed, and evaluated different fueling options to select the most efficient, least-risk and cost-effective scenarios.[163] The Company considers various mines and mining companies, transportation options, and coal quality evaluations.[164] Moreover, the Company considered varying delivery schedules for coal from the BCC mine, the Black Butte mine, and mines located in Wyoming's Southern Powder River Basin (SPRB).[165] As the Company is a partial owner of the BCC mine, the Company can flex coal deliveries up or down, within certain constraints, to better align delivered and consumed coal quantities to benefit customers.[166] The adjacent location of the BCC mine allows for transport via conveyor belt and provides additional cost-savings on transportation charges.[167]

To compare its options, the Company created six different scenarios with varying delivery schedules sourced from these suppliers, with different delivery options and estimated dates for the BCC mine to cease production, varying from a [redacted] closure to a [redacted] closure.[168] [redacted]

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[160] PAC/500, Owen/29.
[161] PAC/500, Owen/29.
[162] PAC/502, Owen/5.
[163] PAC/500, Owen/30.
[164] PAC/500, Owen/30.
[165] PAC/500, Owen/30.
[166] PAC/200, Owen/25.
[167] PAC/502, Owen/11.
[168] PAC/500, Owen/30-31.

[redacted] In addition, the scenarios were created in accordance with the Commission-approved 2023 TAM stipulation, wherein the stipulating parties agreed upon certain standards for the scenarios that the Company would consider in its 2023 Fuel Plan.[170]

The Company evaluated all six scenarios using coal supply volumes and pricing estimates based on indicative pricing received from Black Butte as well as recent coal pricing forecasts from Energy Ventures Analysis.[171] The estimated volumes and rail rates for transportation services are based on prior agreements between the Company and the Union Pacific Railroad for the transport of coal from third-party coal supply sources.[172] The estimated plant modifications and capital requirements, as well as total costs needed to support large volumes of SPRB coal are derived from a detailed third-party study completed in 2017 by the engineering and consulting firm Burns & McDonnell, adjusted for inflation.[173] BCC coal volume costs are derived from the Company's most recent mine plan.[174] [redacted]

To evaluate the cost-effectiveness of the scenarios, the Company completed a Present Value Revenue Requirement (PVRR) calculation, which compares the major components of the Company's system costs and permits the Company to rank scenarios in order of cost-effectiveness and risk.[176] The analysis also accounts for certain Environmental Protection Agency emission requirements, such as the OTR.[177] The costs modeled include coal purchases, natural gas purchases, and system power purchases offset by wholesale power sales.[178] The Company then evaluated the cost profiles for each scenario using its PLEXOS modeling

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[169] PAC/500, Owen/31-32.
[170] Order No. 22-389.
[171] PAC/500, Owen/32.
[172] PAC/500, Owen/32.
[173] PAC/500, Owen/32.
[174] PAC/500, Owen/32.
[175] PAC/502, Owen/13-14.
[176] PAC/500, Owen/32.
[177] PAC/500, Owen/32.
[178] PAC/500, Owen/32–33.

software to derive the generation forecast and consider the impact of each scenario on power purchases, wholesale sales and other significant components of NPC.[179] All six scenarios were ranked based on the total PVRR to determine the fueling options with the lowest PVRR dollar amount.[180] The Company also evaluated and ranked risk potential arising from each scenario, considering risks associated with incremental capital expenditures relating to each fuel scenario; risks associated with adequate coal supplies, including transportation price; risks associated with power market price volatility driven by natural gas prices and the availability of alternative generation resources; and risks associated with new environmental regulations that could change generation at the Jim Bridger plant.[181]

The Company's analysis revealed that selecting both Scenario 5 and Scenario 6 created the least-cost, risk-adjusted option.[182] [redacted]

[179] PAC/500, Owen/33.
[180] PAC/502, Owen/15.
[181] PAC/502, Owen/15.
[182] PAC/500, Owen/34.
[183] PAC/502, Owen/14.
[184] PAC/500, Owen/34.
[185] PAC/502, Owen/14; PAC/500, Owen/35. [redacted]
[186] Highly Conf. Evid. Tr. 47:1-15, 48:11-25, 49:1-21.

The Company ultimately selected these two scenarios, Scenarios 5 and 6, referred to collectively as the "Preferred Scenario," as the best option for fueling the Jim Bridger plant [187] [redacted] The Preferred Scenario reflects the flexibility and low incremental costs associated with the Company's BCC ownership, benefitting customers considerably due to ongoing volatility in the electric, natural gas, and coal markets.[189] The Company determined that the Preferred Scenario has a total company PVRR of [redacted] less than Scenario 4.[190]

In accordance with the Commission's final order in the 2021 IRP filing, the Company filed its 2023 Fuel Plan along with its 2023 IRP on May 31, 2023.[191] The Company will continue evaluating the best fueling options for the Jim Bridger plant and will update the fuel plan after each IRP, in order to ensure that the best and most cost-effective options are utilized.[192] The Company's evaluation and selection of the Preferred Scenario aligns with its prior fuel plan practices, comports with its IRP, and provides the most benefits to customers of any option available. As such, the 2023 Fuel Plan is reasonable, and all costs associated with it should be approved in the 2024 TAM.

C. Sierra Club's recommended 2023 Fuel Plan scenario results in an NPC increase of $20 million in the 2024 TAM.

Sierra Club claims there are methodological flaws in the 2023 Fuel Plan that "severely limit" any ability to identify a prudent course of action. Sierra Club maintains that if the Company had corrected these alleged "flaws," it would have chosen a lower coal consumption

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[187] PAC/500, Owen/34.
[188] PAC/502, Owen/7.
[189] PAC/500, Owen/34.
[190] PAC/500, Owen/36.
[191] PAC/500, Owen/29.
[192] PAC/500, Owen/29.

scenario, Scenario 4.[193] Accordingly, Sierra Club recommends the Commission limit any cost recovery in the TAM to the coal volumes and costs reflected in Scenario 4.[194]

In its reply testimony, the Company updated the 2023 Fuel Plan to correct a modeling error.[195] While this correction reduced the difference between the Preferred Scenario and Scenario 4, the Preferred Scenario remains the least cost-least risk fueling scenario by over [redacted] total company.[196] Furthermore, Sierra Club acknowledges selecting Scenario 4 would result in a total company increase of [redacted] in the 2024 TAM and would have negative implications on its customers.[197]

Sierra Club vaguely suggests the Company's 2023 Fuel Plan contains more errors that could reduce the difference between the Preferred Scenario and Scenario 4 but does not point to any specific error.[198] As outlined below, the Company has demonstrated that Sierra Club's issues with the 2023 Fuel Plan are not due to the flaws in the model.

First, Sierra Club argues that the 2023 Fuel Plan scenarios did not consider a sufficient variety of options with an earlier closure for the BCC mine. [redacted][201] Additionally, the Company has demonstrated that coal market constraints beginning in late 2022, resulted in a depletion of the Company's

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[193] Sierra Club/100, Burgess and Roumpani/21.
[194] Sierra Club/100, Burgess and Roumpani/18.
[195] PAC/500, Owen/36.
[196] PAC/500, Owen/36.
[197] Sierra Club/200, Burgess/5.
[198] Sierra Club/200, Burgess/4-5.
[199] Sierra Club/100, Burgess and Roumpani/31.
[200] PAC/500, Owen/41.
[201] PAC/500, Owen/41.

stockpiles at Jim Bridger and elsewhere;[202] therefore, a scenario assuming greater reliance on the stockpiles at this time is both unrealistic and unreasonable. Sierra Club's recommendation to close the BCC mine in [redacted] is also harmful to customers. Over the years, customers' rates have included the cost of the BCC mine.[203] Through this investment, PacifiCorp customers have effectively purchased and are now entitled to benefit from (i) the option to acquire low-cost BCC mine incremental production as needed, and (ii) the operational flexibility to prudently increase or decrease production as needed within reasonable operating limits.[204] Sierra Club's position that the Company did not properly consider its suggested scenario is flawed, given the impracticalities behind the scenario and the benefits BCC mine supplies to customers.

Second, Sierra Club argues that the Company should have excluded 2023 costs from the PVRR calculation, because 2023 is irrelevant for planning purposes and inflates the benefits of the Preferred Scenario.[205] However, Sierra Club's concern is misplaced because the Company starts its planning horizon with the year in which the plan is filed.[206] The 20-year planning horizon for the 2023 IRP begins in 2023. Since the 2023 Fuel Plan is synced with the 2023 IRP in timing, the Company properly used the 2023 start date for the planning horizon for the 2023 Fuel Plan.[207] In any event, Sierra Club acknowledges that the inclusion of 2023 in the analysis contributes to only [redacted] of the [redacted] difference between Scenario 4 and the Preferred Scenario, making it immaterial for the overall scenario selection.[208]

Third, Sierra Club argues that the scenarios have inconsistent assumptions, specifically that the scenarios should have reflected an equal amount of "other generation," made up of renewable energy mixes such as hydro and wind power and should reflect the same 2023 costs

[202] PAC 200, Owen/6.
[203] PAC/500, Owen/36.
[204] PAC/500, Owen/36.
[205] Sierra Club/100, Burgess and Roumpani/22-23.
[206] PAC/500, Owen/39.
[207] PAC/500, Owen/39.
[208] PAC/900, Owen/19.

attributable to operating the mine.[209] Sierra Club argues that there is a substantial difference in the amount of "other generation" that was modeled in Scenario 4 and the Preferred Scenario.[210] Sierra Club maintains that this unexplained difference in "other generation" is improperly inflating benefits under the Preferred Scenario.[211] However, the differences in "other generation" between scenarios are largely a function of the differing assumptions in Scenario 4 and the Preferred Scenario. [redacted] As such, the 2023 costs are properly differentiated between scenarios, and the benefits of the Preferred Scenario are not attributable to the other generation but the effect of the difference between the high and low generation scenarios. The differences between the scenarios do not reflect a flaw in the analysis but rather the varying effects of the assumptions built into the scenarios.

Finally, Sierra Club takes issue with the Preferred Scenario, arguing that the Company made its selection based on the Preferred Scenario's inclusion of a higher volume of BCC coal.[216] Sierra Club maintains that Scenario 4, which includes a lower volume of BCC coal, is the prudent option because it "reduces PacifiCorp customers' exposure to one of the Company's most costly coal plants."[217] But Sierra Club ignores the benefits and cost-savings associated with

[209] Sierra Club/100, Burgess and Roumpani/29, 32.
[210] Sierra Club/200, Burgess/4.
[211] PAC/900, Owen/20.
[212] PAC/502, Owen/14.
[213] PAC/502, Owen/14.
[214] PAC/502, Owen/14, 24.
[215] PAC/502, Owen/14, 25.
[216] Sierra Club/200, Burgess/1.
[217] Sierra Club/200, Burgess/1.

coal from the BCC mine. Sierra Club additionally ignores that the high production under the Preferred Scenario allows for the operation of two draglines.[218] As established, Scenario 4 is based on operating a single dragline.[219] [redacted]

D. Sierra Club's recommendation to require an annual fuel plan is unduly burdensome and conflicts with the purpose of the long-term analysis.

Sierra Club recommends the Commission require the Company to file an annual long-term fuel plan.[224] Sierra Club argues that an annual filing is necessary to evaluate the cost recovery for BCC fuel because the Company does not have a CSA governing such coal supply.[225]

A fuel plan is "periodic" and "long-term" because it covers multiple years and requires large-scale planning.[226] It would be impractical to prepare a fuel plan annually. In addition, the Commission has directed PacifiCorp to file its fuel plans in conjunction with the Company's IRP.[227] The conjoined timing of the IRP and fuel plan is reasonable because the IRP relies on data developed for the fuel plan, and the fuel plan relies upon the resource mix in the preferred

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[218] PAC/502, Owen/14.
[219] PAC/502, Owen/14.
[220] Highly Conf. Evid. Tr. 51:2-25, 52:5-20.
[221] Highly Conf. Evid. Tr. 52:5-13; 57:1-15.
[222] Highly Conf. Evid. Tr. 52:5-13.
[223] Highly Conf. Evid. Tr. 53:18-25; 54:1.
[224] Sierra Club/200, Burgess/8.
[225] Sierra Club/200, Burgess/8.
[226] PAC/900, Owen/21.
[227] PAC/500, Owen/41.

portfolio from the IRP filing.[228] Sierra Club's proposal would disconnect the IRP and the fuel plan, which is problematic and unnecessary.

IV. CONCLUSION

PacifiCorp respectfully requests that the Commission approve cost recovery of GHG compliance costs imposed by the Washington Cap and Invest Program and approve situs assignment of no-cost allowances to Washington customers. The Company's treatment of Cap and Invest Program costs is consistent with general ratemaking principles, the 2020 Protocol, Washington law, and sound regulatory policy.

PacifiCorp also requests that the Commission: (1) approve the Hunter/Gentry CSA; (2) approve recovery of costs associated with the Preferred Scenario under the Company's 2023 Fuel Plan; and (3) reject Sierra Club's recommendation to convert Jim Bridger's biennial, long-term fuel plan process into an annual filing.

Dated this 22nd day of September 2023.

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[228] PAC/500, Owen/41.

CERTIFICATE OF SERVICE

I certify that I delivered a true and correct copy of the confidential and highly confidential pages of **PacifiCorp's Opening Brief** on the parties listed below that have signed the protective order(s) via electronic mail in compliance with OAR 860-001-0180.

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Dated this 22nd day of September, 2023.

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