ORDER NO. 21-379

ENTERED Nov 1, 2021

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 390

In the Matter of PACIFICORP, dba PACIFIC POWER, 2022 Transition Adjustment Mechanism.	ORDER

DISPOSITION: NET POWER COSTS APPROVED SUBJECT TO ADJUSTMENTS

I. SUMMARY

The purpose of the Transition Adjustment Mechanism (TAM) proceeding is to annually update net power costs (NPC) and to set transition adjustments for Oregon customers who choose direct access in the November open enrollment window. The rates will become effective on January 1, 2022. In this order, we decide the contested issues for PacifiCorp, dba Pacific Power's 2022 TAM. We adopt a $3.4 million reduction to PacifiCorp's market cap proposal[1] and a $1.09 million reduction to account for nodal pricing model operational benefits.[2] Together these two adjustments reduce PacifiCorp's requested NPC amount by $4.49 million Oregon-allocated or approximately 1.5 percent. We also direct PacifiCorp to provide additional information that we find is necessary in future TAMs to facilitate parties' review of new Coal Supply Agreements (CSAs) and to evaluate PacifiCorp's management of established CSAs.

II. BACKGROUND AND PROCEDURAL HISTORY

In this case, PacifiCorp proposed a $1.1 million estimated increase in Oregon-allocated NPC for calendar year 2022.[3] The rate increase reflects higher Oregon loads when compared to the 2021 forecast loads, increased power purchases, and increased wheeling expenses, offset by decreased coal fuel expense. Other significant line items in the 2022 TAM are an increase in Energy Imbalance Market (EIM) benefits and $68.4 million in Production Tax Credit (PTC) benefits (Oregon-allocated).[4]

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[1] Staff/800, Dlouhy/24.
[2] Staff/900, Gibbens/12.
[3] PacifiCorp Opening Brief at 1, n 1 ("This amount reflects the $1.7 million increase in the TAM reply update, less a correction for the WAPA firm transmission costs of $609,086.").
[4] PacifiCorp Opening Brief at 1.

Following the intervention by the Alliance of Western Energy Consumers (AWEC), Calpine Solutions, Oregon Citizens' Utility Board (CUB), Small Business Utility Advocates (SBUA), and Sierra Club, the five parties and Staff filed opening testimony and exhibits on June 9, 2021. PacifiCorp filed its updates and corrections to the NPC and reply testimony and exhibits on July 9, 2021. In its update, PacifiCorp accepted three adjustments proposed by the parties: (1) Staff's proposal to improve EIM benefits modeling, (2) certain Staff adjustments to the modeling of greenhouse gas (GHG) benefits, and (3) AWEC's adjustment to the PTC rate.[5] Those adjustments, combined with other GRID updates, offset each other, and PacifiCorp's requested Oregon-allocated NPC remains approximately $301 million, Oregon-allocated, and a proposed TAM rate increase of $1.1 million.

A hearing in this docket was held on August 26, 2021. PacifiCorp filed an opening brief on September 15, 2021, Staff and parties filed reply briefs on September 28, 2021, and cross-answering briefs on October 5, 2021. PacifiCorp filed its rebuttal brief on October 5, 2021.

PacifiCorp uses an on-going TAM general protective order[6] to govern the exchange of information designated as protected. For this proceeding, PacifiCorp also established a modified protective order[7] to govern the exchange of information designated as highly protected.

III. DISCUSSION

A. Applicable Standard

In the TAM, PacifiCorp retains the burden of proof to demonstrate that its proposed rate or schedule of rates is fair, just, and reasonable.[8] We must base our decision in a contested case on the evidence in the record in the proceeding. As the parties note, we have previously explained: "[t]he TAM effectively removes regulatory lag for the company because the forecasts are used to adjust rates. For that reason, the accuracy of the forecasts is of significant importance to setting fair, just, and reasonable rates. Our

[5] PAC/400, Staples/5-6.
[6] *In the Matter of PacifiCorp 2017 Transition Adjustment Mechanism,* Docket No. UE 307, Order No. 16-128 (Mar 28, 2016).
[7] Order No. 21-086 (Mar 23, 2021).
[8] *In the Matter of Portland General Electric Co. Proposal to Restructure and Reprice its Services in Accordance with the Provisions of SB 1149*, Docket No. UE 115, Order No. 01-777 (Aug 31, 2001).

goal, therefore, is to achieve an accurate forecast of PacifiCorp's power costs for the upcoming year."[9]

B. Coal Issues

1. Requests for Forward-Looking Directives on Coal Issues

a. Filing Requirements for Future TAMs

(1) Overview

Sierra Club, Staff, and CUB raise concerns about the lack of transparency into PacifiCorp's CSA negotiations. To address their concerns, the parties recommend that PacifiCorp be required to file copies of all CSAs and affiliate mine plans in future TAM filings, and that PacifiCorp provide information on economic cycling, coal consumption forecasts, and workpapers.

(2) Parties' Positions

Sierra Club, Staff, and CUB recommend that PacifiCorp be required to provide copies of its coal supply agreements and affiliate mine plans in each TAM filing. The parties state ready access to this information is necessary given that the contracts and mine plans represent a substantial portion of NPC. Staff and Sierra Club describe difficulties with the current discovery approach, which limits access to coal contracts and affiliate mine plans to viewing in person or over a web platform. This limited access does not allow parties enough time to fully review and analyze contract provisions.[10] Staff recommends that PacifiCorp file copies of its CSAs and affiliate mine plans in each TAM, subject to proper handling under a modified protective order. Alternatively, at a minimum, Staff recommends PacifiCorp should be required to provide copies of all new CSA and mine plans in the TAM following execution of the document.

Staff requests the filing directive include three sub-components for additional information. First, for every new CSA subject to review, PacifiCorp provides a detailed explanation of how economic cycling was considered when deciding on minimum take levels in the contract. EIM participation should not exclude plants from economic cycling and PacifiCorp should show whether EIM participation is better for customers than economic cycling. Joint ownership should not exclude plants from economic cycling and PacifiCorp should show whether cycling would be economic. If it is economic, then PacifiCorp should reach out to the co-owner to request they consider

[9] *In the Matter of PacifiCorp 2017 Transition Adjustment Mechanism*, Docket No. UE 307, Order No. 16-482 at 4 (Dec 20, 2016).
[10] Staff Reply Brief at 18; Sierra Club Reply Brief at 28.

cycling. Second, PacifiCorp should include a chart comparing MMBtus from the generation forecast used to inform contract negotiations to the MMBtus in the contract. Third, PacifiCorp should include workpapers for the generation forecasts used to inform negotiations for new CSAs.

(3) PacifiCorp's Response

PacifiCorp responds to parties' requests for filing CSAs by stating that the modified protective order allows parties to seek copies of relevant sections of any CSA for use in developing their testimony, and that no party used this provision to request copies of CSA provisions. PacifiCorp explains it does not file CSAs with the Commission or provide full and unredacted copies to parties because its CSAs are extremely commercially sensitive, and PacifiCorp is contractually bound to maintain the confidentiality of the agreements.

PacifiCorp agrees to Staff's requests to include in future TAM filings information related to new CSAs, including an explanation of how economic cycling was considered, a comparison of forecasted generation to minimum take levels, and workpapers used to inform the range of generation used in negotiations.[11]

(4) Resolution

The CSAs and mine plans impact customer costs and PacifiCorp's TAM dispatch enough that regulators and parties need sufficient access to the documents to conduct a thorough review. In practical terms, we imagine that parties require time to think through contract terms, flexibility to discuss with coworkers with subject matter expertise, and the ability to conduct research into other similar agreements, as this is the type of regulatory review Commission employees engage in for any contested agreement. The amount and type of work required is not compatible with in person or screen sharing review.

We stop just short of requiring new CSAs and updated mine plans to be filed with the TAM as a default. It is possible there may be a solution that is in-between the current limited screen sharing review and the full copy filing requirement that PacifiCorp opposes. Because we do not currently have any CSAs filed in the record, we are not certain exactly how much time and access is necessary beyond the current level. We will require that PacifiCorp allow qualified persons to have more access to the CSAs and mine plans than was provided in this TAM, but we leave it to the parties to determine the exact mechanics. The modified protective order is entirely customizable, and parties may want to consider whether it may be tailored next year to more effectively meet their needs

[11] PacifiCorp Rebuttal Brief at 45-46.

for access, while ensuring there are limited copies of the CSAs and mine plans circulating.

We support the parties' agreement for PacifiCorp to provide additional explanatory materials to support future CSA review. More explanation and description is helpful for determining whether a contract is reasonable. PacifiCorp has agreed to Staff's request for a detailed explanation of how economic cycling factored into analysis for a minimum take level, a comparison of the MMBtu level from generation analysis to the contracted-for level, and to provide the workpapers used in analysis of generation forecasts for CSA negotiations.

b. Future CSAs: Required Analysis and Best Practices Guidelines

(1) Parties' Positions

CUB requests Commission guidance on a process for examining the viability of coal units with questionable economics in future proceedings. CUB cites Jim Bridger as an example of how IRPs reveal benefits from early closure, but do not give direction as to how the plant should operate during the interim period until it is closed or converted to gas. CUB asserts that intervenors should be able to examine choices, such as whether the plant should operate seasonally or be completely shut down in the TAM. CUB asks the Commission to establish a process that includes various model runs in the TAM, examining various closure dates once a resource's economics approach the uneconomic threshold.[12]

Sierra Club states that PacifiCorp's coal contracts do not merely play an important role in dispatch decisions, they dictate how the coal fleet operates.[13] Sierra Club recommends we adopt best practices for future CSAs that can be used to assess the agreements. Sierra Club provides five possible standards. First, analyze average or full cost modeling, a variety of demand scenarios, and economic cycling to ensure the reasonableness of minimum take provisions. Sierra Club states that modeling coal plant dispatch using the average cost would illustrate the most likely quantity of economically dispatched coal while considering the full set of costs associated with that coal burn. Second, minimum take requirements should be 50 percent of projected coal burn or less, to maximize flexibility. Third, require contract terms that allow the minimum take to be adjusted under changing regulatory and economic conditions. Fourth, minimize the length of coal contracts. Fifth, require that PacifiCorp produce evidence in future TAMs showing it incorporated these best practices before executing each new coal contract.

[12] CUB Reply Brief at 11.
[13] Sierra Club's Reply Brief at 22.

(2) PacifiCorp's Response

PacifiCorp responds that CUB's request will effectively convert the TAM into a resource planning docket akin to an IRP, which is improper.[14]

In response to Sierra Club, PacifiCorp states its coal procurement strategy ensures system reliability with a reliable fuel supply. PacifiCorp maintains that minimum take obligations are PacifiCorp's commitment to the coal producer that coal will be purchased, assuring the producer to invest sufficient capital in the mine to provide a reliable supply. Coal mines cannot ramp up supply overnight to respond to increased demand from low hydro conditions or high natural gas prices, and executing CSAs with reasonable minimum take provisions better ensures the coal will be available when needed.

PacifiCorp responds to Sierra Club's suggested CSA best practices. First, PacifiCorp states that it already forecasts generation using the plant's average costs, has incorporated cycling consistent with the modeling used in the TAM and agrees to continue to do so, and agrees to model multiple demand scenarios, as it did with Hunter. Second, PacifiCorp opposes Sierra Club's suggestion for a 50 percent threshold as unsupported. Third, PacifiCorp states it will pursue risk mitigation clauses in its CSAs that allow it to reduce or avoid its minimum take obligations, but opposes a requirement for those contract terms because counterparties are generally unwilling to contract away the certainty provided by a minimum take provision without receiving other assurances, such as a longer contract term or a much higher price.[15] Fourth, PacifiCorp's approach to CSA duration is to limit the period to five years or less to maintain flexibility in fuel and generation planning.[16]

(3) Resolution

In our finding above, we concluded that regulators and parties must have access to CSAs and mine plans with confidentiality protections, and that in a TAM where a CSA or mine plan is being reviewed, PacifiCorp must include a detailed explanation of how economic cycling was considered, a comparison of the MMBtu level in the generation analysis versus the contract level, and workpapers used for the generation analysis. As stated above, this information is helpful to parties' and the Commission's review of the reasonableness of PacifiCorp's actions. In this section we consider what types of analyses should be conducted in the situation where a plant is nearing retirement or when a minimum take level is likely to be disputed. We set out general expectations but do not create any pre-determined guidelines.

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[14] PacifiCorp Rebuttal Brief at 44.
[15] PacifiCorp Rebuttal Brief at 28.
[16] PAC/200, Ralston/3.

When a CSA extends to a unit's retirement date, we expect PacifiCorp to explain how it incorporates its IRP planning into its TAM-reviewed fuel contracts, or its management of those contracts. When we review a CSA, we will need to understand how PacifiCorp considered future costs in multiyear contracts, especially given that its plans for operating a plant generally would be expected to show declining production before retirement. PacifiCorp will need to explain how it is allowing for an orderly sequence towards retirement and ensuring flexibility for reduced capacity factors and consumption of the coal pile, and how it will manage the contract in the event that circumstances change from those expected when it was signed. We do not require an extra plan or report, and expect the parties will raise different concerns with different units in each TAM, but ultimately, we expect that PacifiCorp will explain its general plan and why it is reasonable for customers.

We do not impose specific guidelines on our future CSA review, yet we emphasize to PacifiCorp that the Commission's review of utility actions for prudence involves, in part, a review of the processes and analyses used by the utility in its decision-making process.[17] The higher the cost and larger the delivery, the more important it is that PacifiCorp shows it has followed a robust decision-making and contingency-planning process, where it considers the benefits and costs of utilizing a short term, a conservative delivery amount, and seeking flexibility within contracts.

2. Coal Supply Agreements Driving Dispatch of Coal Plants

Stakeholders raise concerns that coal contract minimum take provisions are driving coal dispatch.[18] Several coal plants are operating close to their minimum take levels. PacifiCorp ensures these plants' generation levels are not below the contract minimums set forth in the TAM forecast or in actual operations by dispatching the units as if they have no fuel costs up to the contract minimum.[19] Parties argue that GRID is not producing the most economic generation forecast because PacifiCorp imposes pricing manipulations and other constraints.[20]

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[17] *See In the Matter of PacifiCorp Request for a General Rate* Revision, Docket No. UE 246, Order No. 12-493 at 26-27 (Dec 20, 2012).
[18] CUB/100, Jenks/9 (Errata).
[19] CUB/105, Jenks/2 (citing PacifiCorp's response to Sierra Club Data Request 1.5 "For example, suppose a CSA had a provision with a minimum take-or-pay volume of 1 million tons. The incremental price for volumes between zero and 1 million tons would be zero because the take-or-pay volumes are treated as a previously incurred cost.").
[20] Sierra Club Reply Brief at 3.

a. Economic Cycling

(1) Overview

When a coal plant economically cycles in the TAM forecast or in actual operations, it is turned off for a period of time when it is uneconomic. In last year's TAM, the parties agreed that PacifiCorp would not use must run requirements which limit the ability of GRID to economically cycle plants. In this TAM, PacifiCorp included a confidential study allowing coal plants to economically cycle.[21]

(2) Parties' Positions

CUB states the economic cycling study raises concerns about the operations of Jim Bridger. CUB explains that the IRP also suggested Jim Bridger dispatch is uneconomic, as the coal studies associated with the IRP found benefits from retirement of Jim Bridger 1 in [redacted] 2023. CUB is not convinced by PacifiCorp's assertion that Jim Bridger should remain online, albeit at its minimum, because of reliability concerns and the delay involved in bringing a unit back online. CUB suggests that a Bridger unit should be able to temporarily cycle down in 2022 and 2023, until December 2023, at which time the unit can be completely shut down or converted to natural gas.

CUB, Staff, and Sierra Club recommend that PacifiCorp conduct a GRID study that closes Jim Bridger 1 for the [redacted][22] CUB believes the Commission would benefit from seeing how GRID models the unit when given the freedom to economically cycle the unit generally and from seeing whether there are economic benefits from [redacted][23] Staff recommends that the study include practical considerations, such as whether the unit can be cycled off while still allowing necessary maintenance to take place on other units.

Staff notes that, alternatively, an economic cycling study that would identify economic cycling opportunities across PacifiCorp's system could negate the need to review Jim Bridger Unit 1 individually. Staff explains that PacifiCorp's economic cycling study in this TAM resulted in a large volume of "emergency purchases" and that the modeling can be improved to show economic cycling in a way that meets the requirements of a reliable generation plan. Staff suggests reducing the number of coal units that are allowed to cycle off at a given time, by looking for available short-term capacity contracts or other resources that can provide shoulder season capacity at a lower cost than coal, or by

[21] PAC/107, Webb/3.
[22] CUB Reply Brief at 4; Sierra Club Reply Brief at 34.
[23] CUB/200, Jenks/13.

utilizing a new model that is able to consider reliability in its economic cycling decisions.[24]

CUB and Staff also ask us to require that PacifiCorp allow GRID to economically cycle Jim Bridger 1 in its TAM forecasts. This recommendation is subject to PacifiCorp's analysis, determining that economic cycling of Jim Bridger Unit 1 is beneficial to customers, while meeting reliability requirements and ensuring an appropriate maintenance schedule is maintained.

(3) PacifiCorp's Response

PacifiCorp responds that the parties' request to enable Jim Bridger Unit 1 to cycle in the TAM has already been met. PacifiCorp states that, in the 2022 TAM, PacifiCorp removed the "must run" setting for all coal units, including Jim Bridger Unit 1 and PacifiCorp intends to continue doing so in future TAMs.

PacifiCorp responds to the parties' second request for a study of Jim Bridger Unit 1 turned off for the [redacted] by stating there is no reason for the Commission to order a study when each party to the TAM can request such a study and PacifiCorp will provide a single model run based on whatever assumptions the party requests. To the extent that Staff, CUB, or Sierra Club want the company to run Aurora in the 2023 TAM, with the assumption that Unit 1 is cycled off for the [redacted], they can make that request.[25]

(4) Resolution

We direct PacifiCorp to complete a follow-up economic cycling study as Staff requests. We decline to require the specific study that CUB requests because of the potential redundancy between a fleet-wide follow-up cycling study and CUB's targeted study. In the event CUB's question regarding Jim Bridger's economics is not answered in the fleet-wide follow-up cycling study, then CUB may request the model be run specifically following the terms of the 2021 TAM stipulation.

The overall question that PacifiCorp's follow-up economic cycling study should address is whether economic cycling of units, with reliability considerations factored in, creates savings for customers.[26] We recognize that an economic cycling study may not be dispositive in defining the precise levels at which a plant is reasonably operated (given operational realities and economic considerations regarding the structure of the contracts related to fuel supply) but find that such a study is nevertheless highly likely to be

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[24] Staff/700, Anderson/6.
[25] PacifiCorp Rebuttal Brief at 43.
[26] Staff/700, Anderson/5.

beneficial in parties' and our review. This analysis may help inform parties' evaluation of new CSAs and PacifiCorp's management of existing contracts. We find the follow-up study should be informative, and do not go so far as to require PacifiCorp to include specific cycling benefits from the study into its 2023 TAM forecast. PacifiCorp retains discretion to present an accurate and reasonable TAM forecast, and we will of course allow all parties to present, in future relevant proceedings, their views on the implications of the study for cost recovery.

PacifiCorp has indicated that its Aurora model may be capable of considering reliability while identifying which coal units to cycle, which would remedy Staff's main complaint with the cycling study in this TAM. PacifiCorp, Staff, and stakeholders should communicate about the parameters of the follow-up study during Aurora workshops, and PacifiCorp should file the follow-up study with the 2023 TAM.

b. Modeling of Minimum Take Levels

(1) Overview

PacifiCorp uses a "dispatch tier" for coal fuel pricing in GRID. The dispatch tier price is based on the unit's incremental cost, or the cost to produce one additional MWh of energy. PacifiCorp excludes the costs of coal subject to take or pay provisions, because such costs are previously incurred and classified with the fixed costs. PacifiCorp uses the dispatch tier pricing in GRID to determine dispatch. PacifiCorp uses a separate "costing tier" that includes the fixed costs and represents the unit's average costs to calculate the NPC charged to customers.[27]

Sierra Club argues that two of PacifiCorp's modeling practices unreasonably favor coal at the expense of lower cost resources. First, Sierra Club asserts that PacifiCorp's incremental pricing in its "dispatch tier" improperly excludes certain fixed costs, and that PacifiCorp should use accurate incremental pricing for its coal fleet in future modeling. Second, Sierra Club has concerns with PacifiCorp's iterative GRID runs that force the model to project minimum quantities of coal burn and recommends that we require PacifiCorp to disclose the dispatch tier adjustments made in order to meet minimum take requirements.

(2) Parties' Positions

Sierra Club argues that PacifiCorp removes certain costs as fixed that should be treated as variable. By reducing the incremental dispatch tier pricing GRID results assume a plant is significantly less expensive than is accurate. Sierra Club provides four scenarios when

[27] Sierra Club Reply Brief at 4-5.

minimum take requirements are not yet a sunk cost for ratepayers and at least a portion of the coal supply is a variable cost that should be included in the dispatch tier cost. First, PacifiCorp assumes it is bound by minimum take requirements before the contract is approved, such as at Hunter, Dave Johnston, and Craig (discussed below). Second, PacifiCorp assumes obligations when the contracts have not yet been signed for 2022. For example, the assumption that PacifiCorp will have a minimum take with Black Butte for Jim Bridger when that contract has not yet been signed. Sierra Club's last two scenarios are when there is no minimum take requirement, or the minimum take requirement can be avoided under the contract. Sierra Club recommends that we direct PacifiCorp to include all variable coal costs in future modeling, without premature assumptions that ratepayers will be bound by minimum take requirements.

Sierra Club argues PacifiCorp further manipulates its coal plants' pricing through an iterative process, whereby PacifiCorp manually reduces the incremental price until the minimum take requirement is met. In this proceeding, a manual adjustment was made for Huntington, Colstrip, and Hayden. Sierra Club states that PacifiCorp's iterative process is an indication that minimum take requirements are driving uneconomic coal consumption and it is critical that the Commission be aware of when adjustments to a plant's dispatch tier are made and to what degree. Sierra Club explains that PacifiCorp's witness conceded that manual adjustments year-over-year would indicate uneconomic generation.[28] Sierra Club recommends the Commission require PacifiCorp to file in future TAM proceedings the initial incremental price for each coal plant, the final dispatch tier price, and the magnitude of the difference with historical information for the past five years. Sierra Club states that PacifiCorp is already required to provide similar information to the California Public Utilities Commission.[29]

(3) PacifiCorp's Response

PacifiCorp responds that it adjusts the dispatch price for a coal plant only if doing so is necessary to cover a minimum take obligation, which undoubtedly reduces overall customer costs.[30] PacifiCorp states that Sierra Club is incorrect in suggesting that it manipulated the dispatch tier price for plants with new CSAs or open positions in 2022, because those plants did not require any modification to the dispatch tier price in order to meet a minimum take obligation.

[28] Sierra Club Reply Brief at 9 (citing Hearing Transcript at 106:6-11 (Ralston, PacifiCorp) "Q. What, within the TAM, would signal uneconomic production? A. If there was multiple years that we had to force the burns to make the minimum requirement, not just one year, but let's just say the last several years, that would be uneconomic.").
[29] Sierra Club Reply Brief at 10.
[30] PacifiCorp Rebuttal Brief at 23-24.

(4) Resolution

We will require PacifiCorp to provide the information requested by parties but do not direct PacifiCorp to change its specific modeling inputs. These findings are consistent with our conclusions above, that parties (and regulators) should be able to see contracts, analysis, and modeling information that will provide insights that will be helpful in reviewing whether a new CSA is reasonable or whether PacifiCorp is appropriately managing an existing CSA.

As to Sierra Club's specific argument on PacifiCorp's manual adjustments to dispatch pricing, we do not find that PacifiCorp acted unreasonably by accounting for minimum take levels in its modeling of resource operation. However, we agree with Sierra Club's point that the spread between the initial incremental price and the final dispatch tier price is possibly the strongest indicator in the TAM that a plant may be dispatching more than is economically optimal, and that a multiyear period in which that spread is significant should prompt PacifiCorp to consider its options for management of the contract (*i.e.*, to evaluate costs and benefits of alternatives). Rather than require PacifiCorp to report five years of data, we require four years, so that the 2023 TAM should include past pricing from the 2020 TAM forward. Four years is consistent with other TAM modeling such as the market caps that are disputed in this proceeding. We also direct PacifiCorp to include the costing tier for each plant for each year, and the differential between the initial incremental price and the costing tier price so parties can consider the variations in the incremental price discount from plant to plant.

c. Forecasted Generation at Jim Bridger

(1) Overview

Pricing for the Jim Bridger coal supply falls into three tiers: the Black Butte price, the BCC "base" price (which is tied to assumed generation levels at the Bridger Coal Company mine), and the BCC "supplemental" price (which represents coal available to PacifiCorp once the base quantity has been purchased). Sierra Club argues that PacifiCorp has improperly lowered the dispatch tier to [redacted] than actual cost in the costing tier, resulting in GRID assuming Jim Bridger is significantly less expensive than is accurate.[31]

[31] Sierra Club Reply Brief at 5, 12.

(2) Parties' Positions

Sierra Club explains that Jim Bridger is one of PacifiCorp's most expensive coal plants, yet GRID continues to forecast relatively high generation because PacifiCorp lowers the dispatch tier price by using the BCC supplemental coal price for the dispatch tier. Sierra Club asserts that the BCC coal supply has no genuine minimum take requirement. Therefore, it is improper for PacifiCorp to treat the BCC base quantity of coal from the mine as though it were a minimum take requirement and exclude the cost from the incremental price dispatch tier.

Sierra Club states that PacifiCorp determines the amount of coal BCC produces and has discretion to reduce production. Sierra Club explains that PacifiCorp annually develops a BCC mine plan that establishes anticipated coal production, and that PacifiCorp has not evaluated any production levels below the current base plan. Sierra Club concludes that because PacifiCorp is not subject to a minimum take requirement at Black Butte and the majority of BCC costs are variable, the BCC supplemental price tier is not an appropriate incremental price point for the Jim Bridger plant. Sierra Club asserts that the Jim Bridger dispatch tier should more closely resemble the BCC base price. Using a GRID run that approximated this price with the average price (which is lower than the BCC base price) Jim Bridger consumers [redacted] MMBtus, compared to over [redacted] in PacifiCorp's TAM application. Based on these fuel savings, Sierra Club recommends we disallow [redacted] on an Oregon-allocated basis associated with excessive forecasted generation at Jim Bridger.[32]

(3) PacifiCorp's Response

PacifiCorp states that it dispatches the Jim Bridger plant based on the incremental cost to generate additional energy, which for Jim Bridger is the supplemental cost for BCC coal. PacifiCorp determines the incremental (*i.e.*, supplemental) cost based on the cost differential between two mine plans with different production volumes. PacifiCorp asserts this methodology isolates the fixed costs of the BCC mine that are incurred regardless of production levels.[33] PacifiCorp explains that it uses average costs in the IRP modeling for long-term resource decisions. In contrast, the TAM is a short-term forecast therefore, PacifiCorp maintains that it appropriately makes dispatch decisions using short-run incremental costs. PacifiCorp refutes Sierra Club's calculation on Jim Bridger fuel savings and states that when Black Butte costs are added to the BCC fixed costs, there is little cost savings from using average price dispatch.[34]

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[32] Sierra Club Reply Brief at 20.
[33] PacifiCorp Rebuttal Brief at 29.
[34] PacifiCorp Rebuttal Brief at 35.

(4) Resolution

Jim Bridger costs, as translated into modeling inputs and shown in the TAM forecast, merit additional attention both because of their magnitude and because of PacifiCorp's flexibility to alter BCC deliveries. As we have in past TAMs,[35] we again require PacifiCorp to update and file the Jim Bridger Long Term Fuel Plan document in the 2023 TAM. Having studied this fuel plan twice before, we add feedback for PacifiCorp to use in designing the bookends that it studies in the fuel plan.

An updated mine plan should explicitly reflect the changing future of Jim Bridger. We have not lost sight of the realities of somewhat inelastic production levels at a mine, but we encourage PacifiCorp to look at scenarios that may involve even significant change in its management of the resources, such as, for example, the consequences of fueling Jim Bridger solely from BCC or solely from Black Butte. Because of the large size of Jim Bridger, we have some concerns about a pre-set BCC production level or Black Butte delivery that could get in the way of portfolio changes already promised in planning and procurement dockets as new renewables come online. We ask PacifiCorp to ensure that the Jim Bridger fuel plan allows Jim Bridger to decrease output as new generation comes online, a rather drastic dispatch trend forecasted in the RFP.[36]

In response to Sierra Club's arguments about the low cost of BCC supplemental coal driving Jim Bridger's dispatch, we find that it seems reasonable for PacifiCorp to at least be informed by an average cost analysis that may present a different view than the traditional TAM modeling of how the long-term fuel plan could optimize a new Black Butte CSA, the shutdown or conversion of the units, and the level of production at the units by considering the full cost of coal. Again, our finding about what evaluation should take place ahead of new CSAs does not affect our acceptance of PacifiCorp's traditional modeling of a CSA once the CSA is in place and found reasonable.

[35] *In the Matter of PacifiCorp, 2018 Transition Adjustment Mechanism,* Docket No. UE 323, Order No. 17-444 (Nov 1, 2017) ("We also approve PacifiCorp's plan to finalize an updated long-term Jim Bridger fuel plan, which should be filed both in this docket and as an attachment to initial testimony in the 2019 TAM. Jim Bridger coal costs continue to be significant and will require on-going monitoring."); *In the Matter of PacifiCorp, 2019 Transition Adjustment Mechanism*, Docket No. UE339, Order No. 18-421 (Oct 26, 2018) (adopting the parties' agreement to update the plan to shorten the life of Jim Bridger post SB 1547).

[36] Official notice per OAR 860-001-0460 is taken of PacifiCorp's Response to ALJ Bench Request 5 in Docket No. UM 2059 (Aug 17, 2021) (showing a [redacted] in coal generation overall in IRP dispatch beginning in 2025 once the RFP renewable resources are added, and showing Jim Bridger's capacity factor of approximately [redacted] in the 2022 TAM falls to approximately [redacted] in 2025.).

d. Bridger Coal Company Costs

(1) Parties' Positions

AWEC states that PacifiCorp's materials and supplies expenses have been grossly overstated in every year analyzed. In 2020, for example, AWEC asserts the forecast was overstated by 32 percent.[37] AWEC recommends an adjustment based on the historical variances identified between the forecast amounts and the expenses actually incurred, with a $1,175,112 reduction to Oregon-allocated NPC.[38] AWEC maintains that whether PacifiCorp spends the money on coal production or reclamation activity, ratepayers see the costs as power costs, and therefore, the Bridger Coal Company materials and supplies costs should be accurately forecast.

(2) PacifiCorp's Response

PacifiCorp responds that AWEC and Staff propose an adjustment to decrease one line item embedded within BCC coal costs related to the materials and supplies expense. PacifiCorp maintains that overall BCC coal costs have been within 1 percent of the forecasted amount over the last five years. PacifiCorp states that the materials and supplies expense appeared overstated in the last three years because the expenses were incurred both for coal production and reclamation activities, and that reclamation activities were much higher in the last three years.[39]

(3) Resolution

We decline to make an adjustment on this issue. Doing so would require us to impose a downward adjustment based on one individual line-item that may decrease (based on past experience) while ignoring that past actual expenses show that the overall cost category within which that line item fits has been reasonably forecast. We understand AWEC's point that PacifiCorp's forecast levels are based on subjective judgements, and we ask PacifiCorp to include a discussion of these costs in its updated Jim Bridger long term fuel plan so that parties have the opportunity to review components as well as the whole of BCC costs.

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[37] AWEC/100, Mullins/22.
[38] AWEC Reply Brief at 17.
[39] PacifiCorp Rebuttal Brief at 44.

3. *Reasonableness of Coal Supply Agreements*

a. *New Coal Supply Agreements – Hunter, Dave Johnston and Craig*

(1) Overview

PacifiCorp has entered into five new CSAs: two related to Hunter, two related to Dave Johnston, and one related to Craig. CUB, Staff, and Sierra Club commented on the contracts. The three parties raise specific concerns with the new Hunter CSAs which are at the same delivery level as the previous, 20-year-old contract. Parties question why generation at Hunter is not declining when PacifiCorp has reduced coal generation by approximately 32 percent since 2018, both system-wide and at Hunter.[40] The CSAs for Dave Johnston and Craig are not specifically contested but are generally opposed by Staff and Sierra Club due to concerns that PacifiCorp's economic cycling analysis is insufficient to support minimum take levels in new contracts.

(2) Dave Johnston and Craig CSAs

(a) Background

For Dave Johnston, PacifiCorp executed two new CSAs for deliveries from two mines, Caballo and North Antelope Rochelle (NARM), both in the Powder River Basin. Both agreements are [redacted]. The Caballo mine will supply [redacted] and NARM will supply [redacted]. The two new agreements are take-or-pay agreements, although PacifiCorp has the option to [redacted]. Including the new and existing agreements for Dave Johnston, there are [redacted] under contract in 2021, approximately [redacted] of the total [redacted] 2022 TAM forecast.[41] Oregon has an exit date of December 2027 for Dave Johnston.

The new CSA for Craig is with the Trapper Mine for a five-year agreement replacing the previous 11-year agreement. The Trapper Mine is an affiliate captive mine owned by PacifiCorp along with two of the five other owners of the Craig plant. PacifiCorp's share of the mine is 29.14 percent. The agreement has a prescribed flexible annual tonnage nomination. PacifiCorp's share of the annual tonnage nomination has a range of [redacted] million tons.[42] Oregon has an exit date of December 2025 for Craig unit 1 and December 2026 for Craig unit 2.

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[40] CUB/100, Jenks/12; CUB/102, Jenks/1.
[41] PAC/200, Ralston/4-5.
[42] PAC/200, Ralston/9-10.

(b) Parties' Positions

Staff and Sierra Club state that PacifiCorp did not allow Dave Johnston or Craig plants to economically cycle in the analysis that informed its negotiations on the new CSAs.[43] Staff explains that the generation forecast at each plant is dependent on economic cycling outcomes at all of the other plants. Staff asserts that a study that looks at economic cycling of the fleet as a whole is necessary to determine the optimal level of generation at the coal plants. Without it, Staff concludes that it is not possible to know whether the minimum take provisions agreed to by PacifiCorp are reasonable and prudent. Staff recommends PacifiCorp be required to model the five new CSAs without minimum take requirements in the TAM for the duration of the contract term.[44]

CUB explains the Dave Johnston contracts benefit from low and competitive pricing for Powder River Basin coal. CUB is comfortable with Dave Johnston's take-or-pay risk as the delivery level maintains an open position that is reasonable in light of Dave Johnson's low dispatch cost, which makes it unlikely to be economically cycled. CUB states the primary take-or-pay risk would be from a significant outage of the plant and could likely be managed with the open portion of the fueling strategy.[45]

(c) PacifiCorp's Response

PacifiCorp responds that: (1) economic cycling is rare in actual operations; (2) GRID over forecasts cycling opportunities; (3) PacifiCorp modeled economic cycling of its entire fleet in the economic cycling study based on 2021 TAM inputs and it showed [redacted]; (4) PacifiCorp's 2022 TAM also modeled economic cycling of the entire fleet and it showed [redacted]; (5) the generation forecasts used to inform the Hunter and Dave Johnston CSAs specifically modeled cycling of the studied plants; (6) the Craig forecast did not include cycling, but if it had the results would not have impacted the minimum take level; (7) PacifiCorp has flexibility to adjust the Craig minimum take level if needed; (8) the company's modeling, used to forecast generation for the new CSAs, conformed to the economic cycling modeling that Staff agreed was reasonable in prior TAMs and that the Commission approved to set customer rates; and (9) the average cost of these plants including these CSAs in the 2022 TAM ranges from $[redacted]/MWh (Dave Johnston) to $[redacted]/MWh (Hunter) to $[redacted]/MWh (Craig), all of which are below the overall coal fleet average price of $[redacted]/MWh and well below the average price of natural gas generation in the 2022 TAM of $[redacted]/MWh.[46]

[43] Staff Reply Brief at 10; Sierra Club Reply Brief at 25.
[44] Staff Reply Brief at 11.
[45] CUB/100, Jenks/11.
[46] PacifiCorp Rebuttal Brief at 36.

(d) Resolution

We approve the Dave Johnston and Craig CSAs as reasonable. Both the Dave Johnston and Craig CSAs have elements that we believe are reasonable, including that each of them has many of the characteristics of being relatively low cost, having a short duration, providing for flexible delivery, or a reasonable open position in light of the plant's general dispatch level. We note that the new requirements for additional information and analysis, described above, in particular when the CSA is large, expensive, or likely contested, will be helpful to reviews of future CSAs.

(3) Hunter CSAs

(a) Background

PacifiCorp has two new CSAs for Hunter. One CSA with Bronco has a [redacted], [redacted]. The Bronco agreement has a minimum take requirement of [redacted] tons at [redacted] per ton. The second CSA is [redacted] The Wolverine agreement has a minimum take requirement of [redacted] tons at [redacted] per ton and second tier pricing of [redacted] per ton. These CSAs are replacing the previous long-term agreement (20 years).

(b) Parties' Positions

Staff's objection to the Hunter CSA is due to PacifiCorp's lack of a fleet-wide economic cycling analysis to inform coal contract negotiations, as discussed in the previous section. Sierra Club similarly challenges the analysis, stating that PacifiCorp only permitted Hunter Units 1 and 2 to cycle in the spring months and did not allow Unit 3 to cycle at all.[47]

Sierra Club also argues that the minimum take levels in the new contracts are high and put ratepayers at risk of uneconomic generation or paying minimum take penalties. Sierra Club explains that if actual burn is 20-30 percent lower than the current GRID forecast, PacifiCorp will either incur minimum take penalties or force the plant to operate uneconomically. Sierra Club asserts that such a deviation is not unreasonable as similar reduced burn levels have occurred at other PacifiCorp plants, as CUB noted.[48] Sierra Club believes this declining trend will continue for coal generation, and over the course of the contracts, the minimum take requirements are likely to make up more of the expected burn to the point where it is likely within the contracts' time frame that Hunter

[47] Sierra Club Reply Brief at 26.
[48] CUB/102, Jenks/1.

will not economically meet its minimum take obligations. Sierra Club states there is no evidence that PacifiCorp evaluated shorter term contracts and that the Hunter contracts do not have provisions that would allow PacifiCorp to reduce or avoid the minimum take requirements due to an inability to economically use the coal.[49]

CUB has concerns regarding the minimum take provisions in the Hunter contracts but does not recommend any adjustments to this TAM because much of the risk associated with the take-or-pay contracts will fall into the PCAM deadband.[50]

(c) PacifiCorp's Response

PacifiCorp responds that it is highly unlikely that generation at Hunter would unexpectedly drop by [redacted] percent. PacifiCorp states this would put PacifiCorp's expected burn at [redacted] tons which is far below any level of coal consumption at the plant since 2017.[51] PacifiCorp disputes Hunter's past consumption decrease that Sierra Club and CUB cite. PacifiCorp argues the evidence does not support Sierra Club's claim that the minimum take level is too high.

(d) Bench Request Response

The bench request asked for Hunter's historical coal consumption so it could be compared to the new contract levels. PacifiCorp provided a comprehensive table showing coal deliveries (total-plant) and coal consumption (ownership-allocated) since 2017. The bench request also asked for PacifiCorp's analysis of Hunter's future consumption so it could be compared to the new contract levels. PacifiCorp explained that it did a scenario analysis in 2020 before signing the contracts. PacifiCorp showed that for Hunter's "low" scenario the forecasted consumption is: 2021 - [redacted] tons, 2022 - [redacted] tons, 2023 - [redacted] tons.

(e) Resolution

We consider whether PacifiCorp acted reasonably when it executed the two new Hunter CSAs by determining whether PacifiCorp's actions, "based on all that it knew or should have known at the time, were reasonable and prudent in light of the circumstances which then existed."[52] We consider not just the decision made by the utility, but also the decision-making process used to reach that decision.[53]

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[49] Sierra Club Reply Brief at 33.
[50] CUB/100, Jenks/12.
[51] PacifiCorp Rebuttal Brief at 41.
[52] *In the Matter of PacifiCorp Request for a General Rate* Revision, Docket No. UE 246, Order No. 12-493 at 25 (Dec 20, 2012).
[53] *Id. a*t 26.

We find that PacifiCorp's analysis supports a prudence determination for the first three years of the contracts, through 2023. Hunter's past consumption averaged [redacted] million tons per year for the last 5 years, supporting the new CSA's delivery level at [redacted] million tons as reasonable. However, PacifiCorp's analysis of future consumption data only supports a reasonableness finding through 2023 and is silent on a reasonable consumption level in 2024, which is the final year of the [redacted] tons. We will defer the determination for 2024 and PacifiCorp can present its evidence to support the reasonableness of the 2024 delivery in a future TAM.

b. Old Coal Supply Agreements – Huntington

(1) Overview

In last year's TAM order, we raised concerns about the Huntington CSA. We asked parties to review the Huntington CSA and explained "[w]e are concerned that, because of the minimum take level in the Huntington coal supply agreement, PacifiCorp may not be able to decrease output at Huntington in coming years when other lower-cost generation is available."[54] The Huntington CSA is a long-term agreement that stems from the Deer Creek Mine settlement.[55]

(2) Parties' Positions

CUB states that in 2015 it joined PacifiCorp in arguing that the Huntington CSA was prudent, based in large part on PacifiCorp's representations that the contract contained broad termination rights relating to environmental laws and regulations.[56] CUB states the current issue is not whether the contract was prudent in 2015, or whether environmental laws or regulations directly impact operations of the plant. Rather, the issue is whether new environmental laws in multiple states who have increased renewables have made burning coal at the minimum levels in the contract uneconomical.[57] CUB cites to studies

[54] *In the Matter of PacifiCorp 2021 Transition Adjustment Mechanism*, Docket No. UE 375, Order No. 20-392 (Oct 30, 2020).
[55] PAC/200, Ralston/12 (citing *In the Matter of PacifiCorp, Application for Approval of Deer Creek Mine Transaction*, Docket No. UM 1712, Order No. 15-161 (May 27, 2015)).
[56] CUB/100, Jenks 13-14 (citing Docket No. UM 1712, PAC/500, Crane/7 (Mar 19, 2015) ("Q. Parties are also concerned that the long-term CSA creates an incentive for the Company to continue to burn coal at Huntington when it would otherwise be uneconomic to do so and therefore limits the Company's future options. Please respond. A. Because the Company can exercise its termination rights if it becomes uneconomic to burn coal at Huntington, there is no incentive to continue burning coal when it is uneconomic to do so and the Company's options are not limited.")).
[57] CUB/100, Jenks 14 (citing Oregon SB 1547 that phases out coal plants and required 50 percent renewables, and that Washington and California have passed 100 percent clean electricity laws).

showing that increased renewables reduce wholesale market prices, and that PacifiCorp exists in a market that reflects the impact of environmental laws and regulations.

CUB states that to justify pursuing the termination clause, the benefits must outweigh the risks and that PacifiCorp must be able to demonstrate that uneconomic dispatch would not be occurring but for increased environmental regulations. CUB states the legal risks of terminating the contract and the cost risks of an increased coal price have to be weighed against the value of termination, which in this case is [redacted] but may increase in coming years.[58] CUB argues that PacifiCorp has a responsibility to manage the contract prudently, including the termination clause.[59] CUB recommends that PacifiCorp conduct an analysis to determine whether the Huntington CSA is leading to uneconomic dispatch of the plant, whether it is due to new environmental laws and regulations, and whether it is in customers' interest to invoke the contract termination provisions by weighing the value of termination against any risks.[60]

(3) PacifiCorp's Response

In response, PacifiCorp agreed to continue to monitor market and regulatory conditions to assess whether there is an opportunity to invoke the termination clause, but does not find those conditions exist at this time.

(4) Bench Request Response

PacifiCorp's bench request response provided historical modeling information for Huntington. PacifiCorp described whether adjustments were required in the initial 2019, 2020, or 2021 TAM filings to account for Huntington's minimum take requirement. PacifiCorp also provided Huntington's incremental price, dispatch tier prices, and costing tier prices from the 2017 TAM to the 2022 TAM. The data showed that PacifiCorp had to manually [redacted] to have the plant meet its minimum take obligation.

(5) Resolution

We note Staff's initial testimony that "PacifiCorp has to manually increase the dispatch level at Huntington so that the minimum take quantity of coal can be utilized. This indicated to Staff that the minimum take levels in the Huntington contract were not calibrated appropriately for the economic realities even a few years into the future."[61]

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[58] CUB/200, Jenks/20-21.
[59] CUB/200, Jenks/18.
[60] CUB Reply Brief at 13.
[61] Staff/700, Anderson/21.

Staff went on to identify the magnitude of the manual adjustment in this TAM as [redacted] MWh,[62] meaning almost [redacted] of Huntington's 2022 output of [redacted] MWh had to be forced to dispatch in GRID.

At hearing, when asked what, within the TAM, would signal uneconomic production, PacifiCorp responded "if there was multiple years that we had to force the burns to make the minimum requirement, not just one year, but let's just say the last several years, that would be uneconomic."[63] The data in the bench request response shows that PacifiCorp has had to make manual adjustments in GRID for each of the last four years to account for Huntington's minimum take requirement. Although PacifiCorp did not have the detail to identify the MWh magnitude of the adjustment, the differential between the incremental price and the dispatch tier price is even larger in 2019, 2020, and 2021, than it is in this TAM, indicating similar or even greater amounts of coal burn that PacifiCorp had to coax into the TAM dispatch to meet the minimum take level.

Confidential Table 1.[64]

[redacted]

With this review we find that a portion of the Huntington minimum take delivery amount is not economic in today's energy market that is shaped by new environmental laws, even if the minimum take levels were structured in a way that PacifiCorp believed to be reasonable at the time the contract was entered into. Given how many years remain in

[62] Staff/700, Anderson/22-23 (citing Staff/702, Anderson/12, PacifiCorp's response to Staff DR 162).
[63] Transcript at 106 (Aug 26, 2021) (Ralston, PacifiCorp).
[64] PacifiCorp Response to ALJ Bench Request 5 (table listing the values).

this contract, with a term that runs to December 31, 2029,[65] the four-year trend of manual adjustments causes us significant concern. With the data we have beginning in 2017, Huntington's minimum take delivery amount appears economic in 2017 and 2018, but in 2019 lower cost generation in GRID would have been available, if PacifiCorp had the flexibility to pursue it.

In 2019 PacifiCorp began bringing on additional wind energy with repowered wind facilities, followed by approximately 1,500 MW of new wind resources in 2020 and 2021. In the rate case where we reviewed some of these costs, we considered multiple benefits including the zero fuel-cost energy that lowers NPC, renewable energy certificates (RECs) which can be sold in the market or used to comply with Oregon's renewable portfolio standard targets, and reduced carbon emissions from PacifiCorp's resource portfolio to mitigate risk associated with potential future state policies (which have since become a reality with Oregon's HB 2021, including early action options for emissions reductions).[66] We find that beginning in 2019 the energy market began to have noticeable price decreases as RPS requirements in the West increased and tax-incentives induced accelerated addition of new renewable resources. The recently approved 2021 RFP short list demonstrated this issue is highly likely to intensify through the 2020s. In that docket, PacifiCorp again pointed to the multiple benefits of building transmission by 2024 and adding significant generating resources, including zero fuel-cost energy that lowers the NPC and emissions reductions from the Utah coal plants specifically.

Circumstances have changed since our initial determination on this CSA, and because PacifiCorp cannot economically consume Huntington's entire [redacted]-million-ton minimum take amount in today's market, it needs to show that it is managing the contract in today's environment. Going forward, we agree with CUB that PacifiCorp needs to present analysis on the costs and benefits of pursuing Huntington's [redacted]. If PacifiCorp does not thoroughly explore the costs and benefits of contract termination or renegotiation, we would be willing to entertain an argument for a disallowance.

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[65] PAC/200, Ralston/11.

[66] *In the Matter of PacifiCorp, Request for a General Rate Revision*, Docket No. UE 374, Order No. 20-473 (Dec 18, 2020).

C. Other Contested Issues

1. Market Caps

a. Introduction and Background

CUB explains that PacifiCorp's power plants serve load first, and excess generation is sold to market if the production cost of the generator is under the market price. The issue with GRID's modeling of sales to market (also referred to as off-system sales) is that GRID does not predict market demand or limit sales, so market caps are inserted to limit the volume of sales.[67]

The existing market caps are based on the maximum sales over the last four years. PacifiCorp seeks to base the market caps on the average sales over the last four years. The methodology provides four separate data points for each month and hub in high load hours, and for low load hours. The dispute is whether the market cap is the highest of the four data points or the average of the four. PacifiCorp explains the effect of a lower market cap is to reduce the market depth at each hub, which reduces market sales modeled in GRID, and increases NPC.[68]

The parties' arguments on market cap methodology involve three separate sets of precedent: a TAM order, a rate case order, and a PCAM order. The current market cap methodology (maximum of averages) was litigated and adopted in the 2013 TAM.[69] Parties state that the Commission approved the maximum of averages as the middle ground between the average of averages approach (PacifiCorp's position) and no market caps (Staff's position). The rate case is where PacifiCorp's overall NPC under-recovery was litigated in 2020. The rate case order states "PacifiCorp may be able to make targeted forecast adjustments to remedy specific issues with its under-recovery."[70] Lastly, recent Power Cost Adjustment Mechanism (PCAM) orders have a section which summarizes PacifiCorp's filing with "PacifiCorp states the main deviation in power costs was due to a decrease in wholesale sales revenues relative to the forecast, with the actual volume of wholesale sales 68 percent less than forecast."[71]

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[67] CUB/100, Jenks/2-3.
[68] PAC/100, Webb/12.
[69] *In the Matter of PacifiCorp 2013 Transition Adjustment Mechanism,* Docket No. UE 245, Order No 12-409 at 7 (Oct 29, 2012).
[70] *In the Matter of PacifiCorp Request for a General Rate Revision,* Docket No. UE 374, Order No. 20-473 at 130 (Dec 18, 2020).
[71] *In the Matter of PacifiCorp 2019 Power Cost Adjustment Mechanism*, Docket No. UE 379, Order No. 20-489 (Dec 29, 2020).

Next year Aurora will include prices at load points across the region as a whole. Parties think Aurora should more accurately model both short-term sales and purchases. PacifiCorp indicates that the market cap adjustment may still be needed in Aurora.

b. Parties' Arguments

PacifiCorp proposes replacing the current maximum of averages market cap methodology with the average of averages approach. PacifiCorp states the average of averages approach to market caps uses the same basic methodology as the maximum of averages approach, with both relying on a rolling four-year average by month, by market, and by high and low load hours. PacifiCorp states the only difference is that the average of averages approach sets the cap at the historical average, while the maximum of averages approach sets the cap at the highest sales level reflected in the historical data.[72]

PacifiCorp explains the market cap change reduces off-system sales volume by approximately 16 percent (or 1.4 million MWh total-company) in this case and increases NPC by $5.1 million (Oregon-allocated).[73] PacifiCorp believes the market cap change is conservative and argues that even under average of averages market caps, it is likely to continue to forecast more off-system sales than it can achieve in actual operations.[74]

PacifiCorp criticizes the maximum-of-averages approach as using the most extreme outlier cap value in the historical record for every month, contrasted with the average of averages method, which includes extreme outlier values in the four-year average but does not rely on them exclusively to set the market cap. PacifiCorp maintains that its proposed market caps better approximate actual sales opportunities, and therefore mitigate the potential for future under-recovery.

Staff, AWEC, and CUB oppose the market cap change. CUB provides several possible reasons as to why GRID over forecasts market sales, such as outlier weather events that are not captured in GRID's weather normalized approach. CUB also suggests that extra generation has been moved to EIM activity, as generation and transmission can either be committed to the EIM, or to a short-term sale, not both.[75] CUB also argues that the new low-cost renewables that have come online in recent years should increase future sales because it is lower cost than the market price.[76]

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[72] PacifiCorp Opening Brief at 10.
[73] PacifiCorp Opening Brief at 6.
[74] PacifiCorp Opening Brief at 7.
[75] CUB/200, Jenks/3-8.
[76] CUB/100, Jenks/4.

Staff, AWEC, and CUB also argue that PacifiCorp has not demonstrated that is has chronically over forecast off-system sales in recent TAMs and that the over forecast PacifiCorp presented in this case appears larger when viewed in isolation. Staff and CUB claim that PacifiCorp has an offsetting over forecast of purchases, which are a cost to customers.[77] Staff and CUB state that the dollar amounts are similar and offsetting when the missed net margins on sales are compared to cost of over forecasted purchases. CUB explains that the costs associated with the PPA or fuel used for sales are also recovered in NPC, so to determine the magnitude of the over forecast PacifiCorp needs to identify the missing net margin from sales, not the missing revenue.[78] AWEC finds that off-system sales are not over-estimated when adjusted for bookouts.

CUB, AWEC, and Staff suggest alternatives. CUB states that it looked for a methodology that would be forward looking and did not find one. CUB suggests for each market hub, PacifiCorp set the cap at the mid-point between the average of averages approach and the maximum of averages approach.

Staff asserts the best solution is to make the model more realistic and that to prove a different approach is superior, PacifiCorp should have produced GRID runs from 2013 to 2020 using the average of averages approach.[79] Staff recommends leaving the market caps unchanged and decreasing NPC by \$5.1 million (Oregon-allocated). Staff's alternative recommendation is to calculate market caps with the "third quartile of averages" which reduces NPC by \$3.4 million (Oregon-allocated) by averaging the two highest values of the four highest monthly sales at each hub. Staff reasons that this will still portray market depth while also addressing PacifiCorp's concern about GRID's over forecast of sales. Staff states the change in market caps should be for one year only, and how to approach market caps should be considered with Aurora next year.

c. Resolution

We begin by considering our statements from the rate case order:

> Between now and 2024, PacifiCorp may be able to make targeted forecast adjustments to remedy specific issues with its under recovery. The TAM is an annual filing and PacifiCorp has an annual opportunity to improve its forecast, just as it did in the 2016 TAM when it introduced the DA/RT mechanism to increase the volume and modeled cost of balancing

[77] Staff Reply Brief at 5.
[78] CUB/200, Jenks/6 ("A utility will generally sell into the market if the market price is greater than the incremental cost of production and transmission. The margin on the sale—the difference between the price and the incremental cost of production and delivery—is what counts towards the bottom line.").
[79] Staff Reply Brief at 7.

> transactions to increase GRID's balancing costs. PacifiCorp does not necessarily need to develop a complex new adjustment, but may be able to improve its forecast accuracy with straightforward inputs or limits. For example, Staff shows that PacifiCorp's sales to market (also referred to as off-system sales) are being over-forecast, finding a "gross over-estimation of the sales benefit". PacifiCorp did not address the feasibility of reducing this component of its forecast and it is something that may be considered in the TAM. With PacifiCorp's upcoming transition to a new power forecast model (AURORA) there may be other options for improving PacifiCorp's forecast that will emerge once the parties begin training with the model.[80]

In the rate case order we described PacifiCorp's annual opportunity to "improve its forecast" and "improve its forecast accuracy". Ideally, this could occur through a fix to make the modeling itself more accurate, and not an out-of-model manual adjustment that changes every year to limit the model. We are optimistic that improved, more accurate modeling may be realized with the rollout of Aurora in PacifiCorp's 2023 TAM. Because of the imminent change to a new model and the unknown sales level that Aurora will produce, we limit our finding on market caps to the 2022 TAM only.

Next, we consider whether PacifiCorp has demonstrated that its average of average market cap proposal will make GRID's forecast of sales better or more accurate. As CUB pointed out, none of the market cap proposals forecast the level of market sales expected on a going forward basis. GRID's modeling cannot predict the depth of the market or whether the market demand will be there. All of the proposals before us are approximations of market depth based on past actual sales.

We look to the record to determine which proposal is most accurate based on the information available. PacifiCorp's table comparing its overall annual forecast of sales volume compared to actual sales volume shows that overall actual sales are approximately 6 million MWh per year for the last four years while its forecasted amount of sales is close to 13 million MWh over the same period. This data supports PacifiCorp's position that GRID does over forecast off-system sales with the maximum of averages market caps. The data alone also supports PacifiCorp argument that from a rate-setting perspective, the average of averages is reasonable as it most closely

[80] *In the Matter of PacifiCorp Request for a General Rate Revision,* Docket No. UE 374, Order No. 20-473 at 130 (Dec 18, 2020) (citations omitted).

approximates the historical average over the last four years.

	Short-Term Sales (MWh)		
	Actual[1]	Forecast[2]	(Below)/Above Forecast
2012	7,746,564	9,360,282	(1,613,719)
2013	7,867,127	11,529,969	(3,662,842)
2014	8,130,895	11,152,711	(3,021,816)
2015	7,619,541	11,420,069	(3,800,527)
2016	6,018,797	12,139,446	(6,120,649)
2017	6,651,663	13,806,284	(7,154,620)
2018	7,765,501	13,977,258	(6,211,757)
2019	4,947,298	15,623,544	(10,676,246)
2020	4,885,911	13,887,647	(9,001,736)
2021		8,845,440	
2022 (Direct Average of Averages)		6,693,996	
2022 (Direct Maximum of Averages)		8,055,722	

We must also consider the parties' arguments which persuasively demonstrate that there are other related and offsetting costs in PacifiCorp's forecast. Important to our determination is the parties' explanation (and PacifiCorp's data) showing an offsetting over forecast of purchases.[81] We also agree with CUB's explanation that the data overstates the problem because of how NPC covers the PPA or fuel price of over forecast sales, so PacifiCorp's under recovery is limited to the margin on the sale (the difference between the production cost and the sale price). PacifiCorp's data also shows that in 2021 and 2022 GRID produced a lower volume of sales even with the maximum of averages market cap, and it is too soon to know if that adjustment will bring the forecast closer to actuals.

We conclude that the most reasonable approach for the 2022 forecast is a compromise position. We adopt Staff's alternative recommendation, which CUB also supports as reasonable, to calculate market caps with the "third quartile of averages" which reduces NPC by $3.4 million (Oregon-allocated) by averaging the two highest values of the four highest monthly sales at each hub. This adjustment applies only to the 2022 TAM. We will evaluate the reasonableness of Aurora's forecast when we see it in the 2023 TAM.

2. *Nodal Pricing Model Benefits*

a. Overview

PacifiCorp states that net power costs and nodal pricing model (also referred to as NPM) are framework issues in the 2020 Protocol and currently part of the ongoing Multi State Protocol (MSP) negotiations. PacifiCorp notes that the 2020 Protocol contemplates that the nodal pricing model will be used for cost allocation beginning in 2024.[82] PacifiCorp

[81] PAC/400, Staples/23-24.
[82] PAC/1100, Wilding/3.

states that to have the information necessary (*i.e.*, day-ahead, hourly locational marginal prices (LMP)) to allocate NPC using the nodal pricing model, PacifiCorp contracted with the California Independent System Operator (CAISO) to receive optimized day-ahead advisory schedules. PacifiCorp began nodal pricing model service in January 2021 for operations.[83] The day-ahead schedules from CAISO are used to inform PacifiCorp's day-ahead schedules.[84] In this TAM PacifiCorp includes $8.4 million total-company in CAISO service fees for the day-ahead schedules from CAISO.[85]

PacifiCorp explains the differences between the EIM and nodal pricing model. EIM is within the hour and the nodal pricing model is the day-ahead period. The other difference is the footprint; EIM co-optimizes all EIM participants and the nodal pricing model only optimizes PacifiCorp's system.

b. Parties' Positions

Staff asserts the nodal pricing model realizes dispatch benefits beyond GRID's optimization. Staff states that GRID pairs the least-cost generation bubble to serve a load bubble, subject to zonal constraints. In the nodal model each bubble has a locational marginal price (LMP), and the model optimizes generation and transmission together. Staff states that GRID selects the cheapest cost resource to serve load, while a nodal model would instead select the cheapest means to serve. Staff believes that the additional granularity of the nodal pricing model goes beyond GRID's perfect optimization because it identifies the impact each generator has on the overall system.[86]

Staff asserts that the efficiency gains resulting from the new dispatch logic should be passed on to customers in 2022 NPC rates because customers are paying costs related to the nodal pricing model in rates. Staff states that, despite PacifiCorp's representation about nodal pricing model benefits in the 2020 Protocol, PacifiCorp has not quantified the operational benefits. Staff argues that in another circumstance, the company's participation in the EIM, where anticipated benefits associated with a new program were difficult or impossible to quantify, the Commission approved the parties' agreement to match the costs and benefits in rates for PacifiCorp's first year.[87]

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[83] PAC/400, Staples/76.
[84] PAC/1100, Wilding/3.
[85] PacifiCorp Opening Brief at 22.
[86] Staff/1300, Gibbens/5.
[87] *In the Matter of PacifiCorp 2015 Transition Adjustment Mechanism*, Docket No. UE 287, Order No. 14-331 (Oct 1, 2014).

Staff recommends that for the 2022 TAM, benefits be set equal to costs and PacifiCorp's NPC be reduced by $8.4 million total-company, as a proxy for the benefits realized in actual operations from the nodal pricing model.[88] Staff states this is a one-time adjustment, because once PacifiCorp changes to the new nodal model Aurora, the savings realized by CAISO's nodal dispatch logic will be captured by Aurora and customers will realize those benefits through a standard model run. As an alternative, Staff recommends that PacifiCorp perform a TAM model run with the same inputs as GRID, using the Aurora model. The difference would provide parties with information necessary to address the issue in the 2022 PCAM.[89]

c. PacifiCorp's Response

PacifiCorp describes its day-ahead set-up process. In relevant part, CAISO provides PacifiCorp with an advisory day-ahead dispatch schedule. PacifiCorp uses the schedules to create the bids for the EIM market. PacifiCorp checks its dispatch against its optimization model (Gentrader) and may make adjustments in Gentrader to ensure the optimization results from Gentrader are consistent with the nodal pricing model.[90]

PacifiCorp explains that CASIO uses a flow based nodal model that produces a LMP at each node for the day ahead schedules it provides to PacifiCorp. PacifiCorp's Gentrader model uses a zonal topology. PacifiCorp states the benefits from the nodal dispatch are from having a more efficient day-ahead setup, with more transparency into transmission rights. PacifiCorp states this results in fewer changes between the day-ahead setup and real-time dispatch, and thus lower NPC from avoiding those changes.[91]

PacifiCorp disagrees with Staff that there are benefits incremental to the GRID model. PacifiCorp states the GRID model does not include costs associated with changes between the day-ahead setup and real-time dispatch because the GRID forecast is based on a single balancing step and a single set of inputs. PacifiCorp compares this to the intra-hour benefits of the EIM that are already captured in GRID. Because GRID is an hourly model and does not include intra-hour changes, there are no costs in the GRID forecast for those intra hour changes. Accordingly, PacifiCorp continues, the Commission decided against any sort of adjustment to the GRID model to account for the EIM benefits associated with more efficient intra-hour dispatch.

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[88] Staff/1300, Gibbens/6.
[89] Staff/1300, Gibbens/7.
[90] PAC/1100, Wilding/4-5.
[91] PAC/1100, Wilding/5.

PacifiCorp claims that Staff's alternate recommendation that would compare an Aurora forecast to the GRID forecast is not feasible. PacifiCorp maintains there is not sufficient time to produce an Aurora forecast and even if Aurora lowers NPC it could be due to numerous other changes.

Lastly, PacifiCorp asserts the purpose of the nodal pricing model has been previously discussed with stakeholders in docket UM 1050. PacifiCorp states that as a signatory to the 2020 Protocol, Staff agreed that the pursuit of the nodal pricing model was prudent.[92] PacifiCorp further notes that in the 2020 Protocol proceeding, Staff did not argue that the nodal pricing model would also create NPC savings that would be imputed into the TAM.

d. Resolution

After a detailed review of the arguments on this issue, we find that it would be appropriate to make an adjustment to PacifiCorp's filing to reflect some level of cost savings in 2022 NPC. We find that PacifiCorp's approach of forecasting no incremental benefit from its NPM is not well-supported by the record in this case, and that Staff has provided evidence that some incremental cost savings should be expected. We decline to adopt Staff's recommendation to assume that the expected benefit would be equal to the total costs included in PacifiCorp's filing, however, and instead find that PacifiCorp's filing should be adjusted to reflect expected savings of half of its proposed costs.

ORS 757.210(1)(a) establishes the burden of proof applicable in this case, and 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." To meet its burden, PacifiCorp must demonstrate that its proposed rates are just and reasonable, by including an appropriate expectation of benefits that will come about from the NPM.[93] Here, PacifiCorp explains there are actual benefits from the nodal pricing model, and that "the benefits of NPC are embedded in actual NPC."[94] PacifiCorp made similar statements in its 2019 filing of the 2020 Protocol.[95] Staff agrees, and also maintains that the nodal pricing model is expected to provide benefits to NPC. The question in this case, then, is whether PacifiCorp has reasonably included those expected benefits in its proposed rates.

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[92] PacifiCorp Opening Brief at 22.
[93] Order No. 20-473 at 5.
[94] PAC/1100, Wilding/9.
[95] PAC/1100, Wilding/10 (citing *In the Matter of the Application of PacifiCorp for an Investigation of Inter-Jurisdictional Issues,* Docket UM 1050, PAC/300, Wilding/10-11 "[t]he potential operational cost savings will be the result of a more efficient day-ahead setup and the cost savings will be embedded in the actual NPC. These potential cost savings will be impossible to accurately and precisely track as the calculation of such savings would rely on a counterfactual setup of the system without the NPM.").

In order to determine if PacifiCorp's proposed rates are just and reasonable, the Commission would need to know the type and amount of benefits that the nodal pricing model is delivering. Rather than provide such a demonstration, however, PacifiCorp asserts that there are no incremental benefits beyond those that are already included in its GRID model's estimate of NPC. In support of this argument, PacifiCorp explains that:

> GRID has perfect foresight or zero uncertainty. This means that for every hour of the year, GRID knows the exact load (which does not change) and GRID knows the exact dispatch cost of each generation resource. Because of this perfect knowledge, GRID ensures that in its modeling, in every hour, the lowest cost resources will be dispatched, subject to transmission constraints.[96]

In response, Staff argues that the nodal pricing model finds savings as a "better informed model that can optimize to a higher level of precision."[97] Staff explains that the nodal pricing model has the "ability to identify the impact each generator has on the overall system"[98] with "more granular dispatch information resulting in anticipated operational cost savings."[99] Staff explains how GRID divides PacifiCorp's service territory:

> [I]nto twelve load centers and twelve resources bubbles connected via transmission bubbles. This means that GRID does not have the granularity to identify the impact of a single unit on the entire transmission system. GRID only optimizes each bubble subject to the constraints; therefore, the impact of any resource within a bubble to the transmission system is unknown in GRID. GRID simply is not complex enough to fully take into account the limits of the transmission network.[100]

We understand Staff's argument to be that the nodal pricing model realizes benefits by using information about transmission constraints to shape dispatch, not just to limit a path as GRID does. Even PacifiCorp seems to acknowledge this benefit when it explained the nodal pricing model schedules provide traders "more transparency into PacifiCorp's transmission scheduling rights."[101]

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[96] PAC/400, Staples/78.
[97] Staff/900, Gibbens/11.
[98] Staff/900, Gibbens/12.
[99] Staff/900, Gibbens/8.
[100] Staff/1300, Gibbens/3.
[101] PAC/1100, Wilding/5.

We find that PacifiCorp did not adequately rebut Staff's position that there are expected benefits from the nodal pricing model that are incremental to those forecast by GRID. Instead, PacifiCorp relied on its generalization that GRID already takes into account the benefits, without specifically addressing how the differences between GRID and the nodal pricing model could be reconciled with the company's position. On this record, we find that it would be appropriate to make an adjustment to PacifiCorp's rates to reflect an assumption of incremental savings that will accrue from the nodal pricing model. In short, PacifiCorp did not carry its burden of proof on this issue to demonstrate that all of the benefits were already included in GRID.[102]

Although Staff rebutted PacifiCorp's position, we decline to find that the assumed benefit should be deemed to be a full offset of the $8.4 million in projected costs associated with PacifiCorp's use of the nodal pricing model. We find that PacifiCorp's decision to pursue the nodal pricing model is generally reasonable, and therefore we expect that over time its benefits would more than offset its costs. At the same time, we recognize that the benefits of a new system may not necessarily, in 2022, produce benefits that fully offset the program's initial costs.

We find it appropriate to include a $1.09 million reduction to Oregon-allocated NPC as a proxy for nodal pricing model benefits in 2022, reflecting that Staff rebutted PacifiCorp's position that there are no incremental benefits, but also reflecting our determination that those incremental benefits may not be expected to fully offset costs in 2022. This adjustment is limited to the 2022 TAM as we anticipate nodal pricing model benefits across PacifiCorp's two BAAs will be captured with the implementation of Aurora for planning in the 2023 TAM. We note that, over time, the opportunity may arise to co-optimize day ahead planning with additional BAAs. At such time, we expect PacifiCorp to make a reasonable estimate of forecasted benefits to NPC, as it has for forecasted benefits during the initiation and market footprint expansion of the EIM.

3. Fly Ash Revenues

a. Overview

Fly ash is a by-product of the combustion of burning pulverized coal in electric power generating plants. PacifiCorp collects fly ash and is then able to sell the by-product to be used in construction. Fly ash is used by the construction industry to develop concrete,

[102] *In the Matter of PacifiCorp Request for a General Rate Revision,* Docket No. UE 374, Order No. 20-473 at 5 (Dec 18, 2020) ("If the company fails to meet that burden, either because the opposing party presented persuasive evidence in opposition to the proposal, or because PacifiCorp failed to present adequate information in the first place, then PacifiCorp does not prevail because it has not carried its burden of proof.").

bricks, and other building supplies. Because fly-ash is a by-product of coal combustion, its production fluctuates with power production. PacifiCorp produces fly-ash mainly from the Jim Bridger plant, with small amounts being sold from Naughton, Craig, and previously, Cholla.

Presently, fly ash revenues are included in PacifiCorp's 2020 rate base, as decided in docket UE 374. During UE 374, PacifiCorp projected $4,256,000 total-company in national fly ash sales, which was included in base rates.[103] However, according to PacifiCorp's most recent FERC Form 1, the company has nationally made fly ash sales of $3,445,036 total-company in the first quarter of 2021.[104] At its current pace, PacifiCorp is projected to make national fly ash sales of $13,780,144 total-company.[105] This is significantly higher than the projected $4,256,000 total-company in annual revenues included in base rates in UE 374.

The parties' arguments on fly ash revenues involve two past TAM orders. The 2009 TAM Guidelines with the 2010 Update listed specific other revenues to include in the TAM. The 2012 contains guidance on the TAM Guidelines with the statement that "While ICNU may certainly advocate for changes to the TAM, such as the changes proposed here, the TAM guidelines make clear that such changes are to be appropriately addressed in a general rate revision docket or other proceeding, not part of a stand-alone TAM proceeding."[106]

b. Parties' Positions

Staff and AWEC assert that due to a material increase in revenues associated with fly ash sales as compared to the amounts included in current base rates, PacifiCorp's fly ash revenues be considered in the Other Revenue forecast of the TAM.

AWEC and Staff argue that increased fly ash sales should be reflected in the TAM because fly ash is a direct byproduct of burning coal, and therefore is directly related to net power costs.[107] AWEC claims the Commission should include fly ash sales in Other Revenues as this category already includes items that are directly related to new power costs. AWEC explains that while the TAM Guidelines Exhibit B does include examples of select revenue baselines, nowhere in Order No. 10-363, nor the Stipulation underlying

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[103] AWEC/200, Mullins/24.
[104] *Id.* at 24.
[105] *Id.*
[106] *In the Matter of PacifiCorp 2012 Transition Adjustment Mechanism,* Docket No. UE 227, Order No. 11-435 at 6 (Dec 21, 2011).
[107] AWEC/200, Mullins/25.

it, is it specified that those, and only those, sources of revenue identified in Exhibit B would be considered as Other Revenue for purposes of TAM forecasting.

AWEC and Staff believe the increased revenue from fly ash is a multiyear trend and is likely to continue through 2022. PacifiCorp's fly-ash revenues have increased by over 60 percent in the past year and there is strong demand for fly-ash in the US.[108] AWEC states that prior stand-alone TAM proceedings have not presented a factual scenario with a 4-fold increase above the rate case level. AWEC and Staff reason that including these revenues in the TAM ensures that benefits are captured fully between rate cases.

AWEC advocates developing a fly ash sales forecast based on 2020 fly ash sales of $6,851,586 total-company, adjusted to remove the historical sales from Cholla, for $6,504,276 total-company.[109] The higher sales of 2021 would roll into the 2023 TAM forecast.[110] After updating the Other Revenue calculation, AWEC suggests reducing Oregon-allocated TAM revenues by $949,615.[111] Staff agrees with AWEC's proposal for forecasting.

Staff adds that PacifiCorp should update its "Other Revenues" to include any other appropriate revenues in the indicative November filing. Staff is concerned that PacifiCorp has been selectively updating Other Revenues in the TAM and any other new contracts that will increase revenues in 2022 and are appropriate for the TAM should be in this year's November filing.

c. PacifiCorp's Position

PacifiCorp responds that fly ash revenues are in UE 374 base rates and have never been in the TAM. PacifiCorp states that many items in base rates have fluctuated since the rate case.

PacifiCorp also responds that AWEC's proposal is contrary to the TAM Guidelines because revenue is only included in Other Revenue if Order No. 10-363 specifically identifies the revenue source, and fly ash revenue have never been added. PacifiCorp states that initially only one revenue item was included in the stand-alone TAM filing, which was the Little Mountain steam sales. The following year, the 2011 TAM stipulation provided for five additional specific items, including: storage and exchange agreements for the Seattle City Light; Stateline and Foote Creek projects; revenues from

[108] AWEC Reply Brief at 15.
[109] AWEC/100, Mullins/21.
[110] AWEC/200, Mullins/25.
[111] AWEC/100, Mullins/21.

the BPA contact associated with the South Idaho Exchange; steam revenues for Little Mountain; and royalty revenues for the GP Camas contract.

PacifiCorp concludes that since the 2011 TAM, the Commission has never recognized additional Other Revenues in the TAM. In 2012, the Commission rejected ICNU's attempt to include updated retail sales revenue. If AWEC wants to include additional revenues in the TAM, PacifiCorp argues it must propose a change to the TAM Guidelines in a general rate case.

d. *Resolution*

In general, the TAM has long been a highly contested proceeding, and we are wary that opening up the TAM Guidelines could lead to asymmetry. Identifying a single cost or revenue that varies from base rates, without updating base rates as a whole or adjusting for other variations, could result in TAM updates that are not equal, with an imbalance between the cost items that favor PacifiCorp with the revenue items that favor customers. If the revenues are substantial, we recommend that Staff seek to use a deferral mechanism, rather than an adjustment to TAM rates, which we would review under our normal approach to deferrals.

For fly ash revenue specifically, AWEC and Staff have not shown that fly ash revenues are directly related to power production such that they should be included in the TAM. Because we know the production level from PacifiCorp's coal fleet has declined, it is reasonable to conclude that PacifiCorp's increased fly ash revenues are correlated with construction demand and not power production. We decline to require a special update to Other Revenues in this TAM, for fly ash revenues, or any other item.

4. Qualifying Facilities Overforecast

a. *Overview*

Staff explains that, under PURPA, the Public Utility Regulatory Policies Act of 1978, investor-owned utilities are required to purchase power from Qualifying Facilities (QFs), using rates established by the state regulatory commissions.[112] QFs are one of the most expensive resources on PacifiCorp's system, with average costs in this TAM of approximately [redacted]/MWh.[113] We last considered PacifiCorp's QF forecast in the 2018 TAM when we adopted CUB's QF forecast methodology to account for QF delays (Contract Delay Rate - CDR). We recognized that PacifiCorp does not receive accurate

[112] Staff/500, Zarate/8.
[113] Staff/500, Zarate/13; CUB/102, Jenks/1.

information from QF developers about expected online dates and implemented the CDR to apply a rolling three-year average of delay days to the forecasted online date for new QFs.[114]

b. Parties' Positions

Staff is concerned with the historical relationship of actual QF MWh produced to PacifiCorp's projections. PacifiCorp provided summary statistics of QF projections to actual history that Staff presents in this table:[115]

	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

Staff concludes from the data that PacifiCorp has a history of overestimating the MWhs produced from PURPA QF projects and once the CDR methodology was implemented in the 2019 TAM the overestimate declined but remained substantial.

Staff recommends an adjustment to reduce PacifiCorp's QF costs. Staff calculates that PacifiCorp over-recovered QF costs in 2020 by $3.2 million, Oregon-allocated, and Staff reduces that amount by the cost of Mid-C power needed to replace the QF MWh to serve load. Staff ultimately recommends a $1.53 million, Oregon-allocated reduction to PacifiCorp's QF costs.

c. PacifiCorp's Response

PacifiCorp responds that it forecasts QF costs in the TAM based on each individual contract. PacifiCorp states that the contracts vary, some may specify an exact quantity of capacity or energy, or a range bounded by a minimum and maximum, or it may be based on actual operations. PacifiCorp states that for QFs less than or equal to 10 MW, the forecast uses the actual delivery schedule. For renewable QFs over 10 MW, the QF

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[114] *In the Matter of PacifiCorp 2018 Transition Adjustment Mechanism*, Docket No. UE 323, Order No. 17-444 (Nov 1, 2017).
[115] Staff/500, Zarate/12.

forecast is determined the same as the forecast for owned wind generation – for the first four years PacifiCorp uses the developer's P50 estimate from the interconnection agreement. After four years PacifiCorp uses actual performance data based on the full history.[116] PacifiCorp maintains that it is using the best available information from each QF project.

PacifiCorp opposes Staff's adjustment. PacifiCorp argues the adjustment is just a reduction equal to the 2020 over forecast. PacifiCorp states that Staff improperly requests a historical true-up of only one element of NPC, when overall NPC was eight percent more than forecast.

d. Resolution

We will not adopt a QF adjustment in this TAM, consistent with our other findings rejecting adjustments that resemble a true-up of one line item of NPC to align with actual past levels. Nonetheless, we are concerned about PacifiCorp's consistent over forecast of QFs as shown in Staff's data table. In the 2023 TAM we direct PacifiCorp to update the table above with 2021 data, and to address the question of why it has continued to over forecast QFs in recent years. It is our understanding that there are two possible errors with the QFs: the lag in online dates realized for new QFs; or an error in forecasting for existing QFs. It is possible that the 2020 data is still reflecting a lag from new QFs even after the CDR was applied. If new QFs are the issue, then the 2021 and 2022 data should have a more accurate forecast because no new QFs have come into the 2021[117] or 2022[118] forecast. If the error continues in 2021, then PacifiCorp should investigate whether a category of old, non-wind QFs are skewing the forecast and PacifiCorp should address how it can improve the accuracy of its QF forecast.

5. Load Forecast

a. Parties' Positions

SBUA states the 2022 load forecast used in the PacifiCorp's calculation of NPC reflects an increase in Oregon load compared to the 2021 forecast loads in the 2021 TAM. SBUA states that due to the increase in Oregon load, PacifiCorp anticipates it will need to collect approximately $3.3 million more than what was approved in the 2021 TAM. SBUA argues that evidence in this docket puts this forecast into question or supports close examination of the load forecast in the context of the 2020 Protocol 3.1.9 involving

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[116] PAC/400, Staples/43.
[117] *In the Matter of PacifiCorp 2021 Transition Adjustment Mechanism*, Docket No. UE 375, PAC/100, Webb/15 (Feb 14, 2020) ("No new QFs are forecast to come online in the 2021 TAM forecast period.").
[118] PAC/100, Webb/20 ("No new QFs are forecast to come online in the 2022 TAM forecast period.").

load-based dynamic allocation factors. SBUA asserts the return to pre-COVID employment is not projected until the fourth quarter of 2022.[119] SBUA recommends we find that any increase in the TAM is not justified.

PacifiCorp responds that its load forecast is robust, and no other party to this proceeding has questioned the general reasonableness of the Company's load forecast. PacifiCorp argues that SBUA has not provided any evidence to address specific issues with the load forecast or employment in PacifiCorp's service territory. PacifiCorp asserts the Commission should reject SBUA's proposal and recommendations as insufficiently supported in the record.[120]

b. Resolution

SBUA has not shown any inaccuracies in PacifiCorp's load forecast, or in PacifiCorp's application of the 2020 Protocol to the load forecast.[121] We are unable to make a more specific finding on SBUA's arguments due to the limited explanation in the record. We briefly note there may be a misunderstanding of PacifiCorp's testimony on its load variance in the 2022 TAM. PacifiCorp states that "due to the increase in Oregon load, the Company anticipates it will need to collect approximately $3.3 million more than what was approved in the 2021 TAM."[122] Another explanation is that as a result of the load increase, PacifiCorp will collect $3.3 million more than was projected in the 2021 TAM. The $3.3 million surplus was subtracted from PacifiCorp's NPC increase of $4.5 million, resulting in PacifiCorp's initial filing showing a proposed $1.2 million increase in Oregon-allocated revenue requirement for 2022.[123] We note that this calculation is part of each TAM and we find that PacifiCorp's calculation appears correct in the 2022 TAM.[124]

6. Direct Access Opt-Out Charge

a. Overview

The general issue in this proceeding is that Calpine proposes that PacifiCorp's opt-out charge should be allowed to go negative to credit direct access customers who leave the

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[119] SBUA Opening Brief at 5-7.
[120] PacifiCorp Rebuttal Brief at 49-50.
[121] *In the Matter of the Application of PacifiCorp for an Investigation of Inter-Jurisdictional Issues,* Docket No. UM 1050, PAC/101 (Dec 3, 2019).
[122] PAC/100, Webb/3.
[123] PAC/101, Webb/1.
[124] PAC/401, Staples/1.

system. We provide background on the direct access charges and credits before moving to the parties' positions in this case.

Customers that choose the one and three year opt-out program must renew at the end of the term. These customers pay actual Schedule 200 costs for fixed generation and a transition adjustment for Schedule 201 costs for variable power costs that is the difference between the power cost charge and the value of the freed-up energy.[125] In the past the transition adjustment has been a small charge or a small credit, this year PacifiCorp's sample transition adjustment calculation is an average credit of $14.27/MWh during heavy load hours.[126]

Customers that choose the five-year opt-out program permanently leave PacifiCorp's system. These direct access customers pay five years of the same costs described above – actual Schedule 200 fixed costs, and a transition adjustment that is the net cost or credit for Schedule 201 power costs offset by the value of the freed-up energy. Direct access customers in PacifiCorp's five-year program also pay a consumer opt-out charge. The consumer opt-out charge is a forecast of the Schedule 200 fixed costs for years six through ten, brought forward into years one through five, offset by the transition adjustments projected for years six through ten that net projected power costs against the value of the freed-up energy.[127] Calpine explains the current 2021 opt-out charge is $3.76/MWh.[128]

At issue in this proceeding is that PacifiCorp has capped the value at zero for the opt-out charge, so unlike the transition adjustment, it cannot be a credit. If the calculation is allowed to go negative, Calpine explains the 2022 sample opt-out charge would provide for a credit ranging from $1.62/MWh to $4.99/MWh.[129]

b. Parties' Positions

Overall, Calpine, AWEC, and Staff assert that PacifiCorp should utilize its approved methodology to calculate the opt-out charge in a manner that allows it to go negative. Staff recommends this for the 2022 TAM only, and that the Commission more fully address the issue in the docket UM 2024 proceeding. PacifiCorp and CUB state that if the opt-out charge value becomes negative then PacifiCorp should set it at zero in this proceeding and parties may more fully examine this issue in docket UM 2024.

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[125] *In the Matter of PacifiCorp 2016 Transition Adjustment Mechanism*, Docket No. UE 296, Order No. 15-394 at 12 (Dec 11, 2015).
[126] Calpine Solutions/100, Higgins/10-11.
[127] PAC/900, Meredith/3; Calpine Solutions/101.
[128] Calpine Solutions/100, Higgins/14.
[129] Calpine Solutions/100, Higgins/19.

Calpine and AWEC argue that PacifiCorp should not artificially constrain the opt-out charge. Calpine believes the direct access opt-out charge is essentially the same thing as the transition adjustment, and that if PacifiCorp has a projected benefit for years six through ten then the charge should be a credit, like the transition adjustment. Calpine states OAR 860-038-0160(1) requires PacifiCorp to pay a credit to the customer if the net-value is below zero and that PacifiCorp must use the ongoing valuation method approved in docket UE 267 to calculate the consumer opt-out charge.

Calpine and AWEC explain that when the opt-out charge becomes a credit it is because there are net power costs savings attributed to the departed opt-out load in years six through ten, and consequently, costs are not shifted to non-direct access customers.[130] Calpine and AWEC believe that a negative opt-out charge is not a policy issue for docket UM 2024, it is a math issue for this proceeding.[131]

Staff generally agrees with Calpine and AWEC that PacifiCorp should use its approved methodology to calculate the consumer opt-out charge as a freely floating mechanism that can go below zero for this for this proceeding. Staff notes that PacifiCorp has presented no evidence of cost-shifting associated with allowing the charge to go negative. Staff recommends a final determination on the issue can be made in docket UM 2024.[132]

PacifiCorp responds that the direct access opt-out charge is a distinct type of charge from a transition adjustment, and that it should be capped at zero to effectuate its purpose of reimbursing the utility for stranded costs.[133] PacifiCorp and CUB believe that the opt-out charge is intended to prevent cost-shifting to protect the non-participating cost of service customers.[134] PacifiCorp and CUB claim it should be a charge because that was how it was presented and adopted. PacifiCorp argues the opt-out charge was created as its own mechanism separate from the transition adjustment, and therefore should be only a charge.[135]

CUB explains that in docket UM 2024 its position is that the direct access program has already shifted costs from direct access participants to cost-of-service customers because direct access participants purchase energy on the market that does not capture the capital costs of the generating plant. PacifiCorp and CUB explain that other policy issues are being addressed in docket UM 2024 such as if direct access customers must pay for coal

[130] Calpine Solutions/200, Higgins/4.
[131] AWEC/200, Mullins/27.
[132] Staff Reply Brief at 30.
[133] PAC/900, Meredith/2.
[134] CUB Reply Brief at 14.
[135] PAC/1500, Meredith/2-3.

plant closure and decommissioning costs. PacifiCorp and CUB reason that enabling the opt-out charge to go negative is a significant policy issue that should be addressed in docket UM 2024. PacifiCorp and CUB conclude that, in the meantime, it is inappropriate for cost-of-service customers to further subsidize direct access customers.

c. Resolution

We will adopt Staff's position and let the opt-out charge go negative until we fully address this issue in docket UM 2024. We recognize there have been delays in docket UM 2024 and the difficult questions of a cross-subsidy between direct access and cost-of-service customers can be addressed in that proceeding.

In the meantime, we are persuaded by Calpine and AWEC that there is no clear prohibition on the opt-out charge becoming a credit. With our narrow review in this proceeding, it appears that PacifiCorp's fixed costs, and the net value of freed-up energy that offsets the fixed costs, could be similar in years one through five as years six through ten. It follows that the calculation of the differential in years six through ten should function the same as the calculation in years one through five, when the transition adjustment is allowed to go negative.

Our decision here is not precedential with respect to whether we would adopt a policy to direct access that pays customers to leave the system. Our decision in this case is limited to PacifiCorp's TAM proceeding until docket UM 2024 is resolved, and our decision is that PacifiCorp should conduct the calculation as it always has, without adding a constraint on the final value.

d. Renewable Energy Credit (REC) Retirement

Calpine and PacifiCorp agree on a new approach for REC transfers in response to a HB 2021 provision that allows bundled RECs to be retired by the utility on behalf of Electricity Service Suppliers (ESS)for direct access customers. The parties describe a change from the current REC transfer procedure to a REC retirement procedure. PacifiCorp states it will transfer bundled and unbundled RECs into a Western Renewable Energy Generation Information System (WREGIS) retirement subaccount that is specific to each ESS. PacifiCorp agrees to the provisions proposed by Calpine.[136] As requested by Calpine, we approve the parties' agreement.

[136] Calpine/200, Higgins/10-11; PAC/1400, Wiencke/2.

IV. NEXT STEPS

We briefly memorialize a few next steps that the parties agreed on.

A. 2023 TAM Filing Date

The parties agree that PacifiCorp will file the 2023 TAM on March 1, 2022. This date allows PacifiCorp to implement the December 31 forward price curve in its NPC forecast. As requested by PacifiCorp, we agree that PacifiCorp can forego an April 1, 2022 update and that PacifiCorp may provide its Schedule 296 calculation on May 30, 2022.[137]

B. DA/RT Update

The parties agree that PacifiCorp will conduct workshops addressing DA/RT and the transition to Auora prior to filing the 2023 TAM. PacifiCorp plans to conduct workshops on the continued value of the DA/RT adder and its inclusion in the Aurora model.[138]

C. Aurora

PacifiCorp also plans to conduct a workshop outlining the Aurora modeling process itself to promote understanding between Staff, intervenors, and the company about the modeling process ahead of the 2023 TAM.[139]

V. ORDER

IT IS ORDERED that:

1. Advice No. 21-008 is permanently suspended.

2. PacifiCorp, dba Pacific Power, update its net power costs to reflect the changes adopted in this order to establish its Transition Adjustment Mechanism NPC for calendar year 2022 and file its tariffs to be effective January 1, 2022.

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[137] PAC/1000, Staples/56-57.
[138] PAC/400, Staples/32.
[139] *Id.*

3. The directives contained in this order be implemented by PacifiCorp, dba Pacific Power, as described above.

Made, entered, and effective Nov 01 2021.

Megan W. Decker
Chair

Letha Tawney
Commissioner

Mark R. Thompson
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.