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September 15, 2021

VIA ELECTRONIC FILING

Attention: Filing Center
Public Utility Commission of Oregon
P.O. Box 1088
Salem, Oregon 97308-1088

Re: UE 390 – *In the Matter of PacifiCorp, dba Pacific Power, 2022 Transition Adjustment Mechanism*

Attention Filing Center:

Attached for filing in the above-referenced docket is PacifiCorp d/b/a Pacific Power's Opening Brief. Confidential material in support of the filing will be provided to qualified parties under Protective Order No. 16-128 via encrypted zip file.

Please contact this office with any questions.

Sincerely,

Katherine McDowell

Attachment

CERTIFICATE OF SERVICE

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

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Dated this 15th day of September, 2021.

/s/ Alisha Till

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 390

In the Matter of PACIFICORP, dba PACIFIC POWER, 2022 Transition Adjustment Mechanism.	**PACIFICORP'S OPENING BRIEF**

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I. INTRODUCTION

PacifiCorp dba Pacific Power (PacifiCorp or Company) respectfully submits this opening brief to the Public Utility Commission of Oregon (Commission) in support of the Company's proposed 2022 Transition Adjustment Mechanism (TAM) increase of approximately $1.1 million, or less than 0.1 percent.[1] This slight increase reflects higher Oregon load,[2] increased power purchases, and increased wheeling expenses, offset by decreased coal fuel expense.[3] The 2022 TAM includes [redacted] in Energy Imbalance Market (EIM) and Greenhouse Gas (GHG) benefits on a total-Company basis, an increase of [redacted] over the 2021 TAM.[4] The filing also includes $68.4 million in Production Tax Credit benefits and reflects a reduction in net power costs (NPC) of $29.4 million due to new wind resources.[5] Coal generation in the 2022 TAM is [redacted] percent of total requirements,[6] down from 60 percent in 2013,[7] and coal costs are $105.5 million lower on a total-company basis than in the 2021 TAM.[8] The 2022 TAM reflects PacifiCorp's ongoing commitment to reducing GHG emissions and cost-consciously transitioning to a cleaner generation fleet.

PacifiCorp's NPC modeling is largely unchanged from prior TAMs—except PacifiCorp proposed one modest improvement intended to address the Company's persistent and significant under-recovery of actual NPC. In 2020, the Company experienced a $28.2 million shortfall, resulting in a 4-year average shortfall of $23.1 million.[9] Last year, while declining to modify PacifiCorp's Power Cost Adjustment Mechanism (PCAM), the Commission nonetheless acknowledged PacifiCorp's under-recovery and was persuaded by Staff that over-forecasting off-

[1] PAC/400, Staples/5. 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. Unless otherwise stated, all values are expressed on an Oregon-allocated basis.
[2] PAC/100, Webb/3.
[3] PAC/401.
[4] PAC/400, Staples/8. Because PacifiCorp has reinstated the System Generation allocation factor for this proceeding, the numbers here reflect a [redacted] increase to Oregon-allocated EIM benefits. *See* PAC/1000, Staples/53 (removing the EIM allocation factor shift from the 2022 TAM).
[5] PAC/401.
[6] Staff/100, Enright/4.
[7] PAC/100, Webb/32.
[8] *See* PAC/600, Ralston/1-2 (explaining that the Company's coal costs in the 2022 TAM total $146.2 million).
[9] *See* PAC/400, Staples/14 (Figure 2).

system sales was a principal cause of the shortfall. The Commission suggested that PacifiCorp "improve its forecast accuracy [of off-system sales] with straightforward inputs or limits."[10] In response, PacifiCorp revised its current market caps to more effectively limit off-system sales in illiquid markets.

Staff and intervenors have vigorously opposed this modeling change. Indeed, Staff now claims that PacifiCorp does not over-forecast its off-system sales at all,[11] despite its opposite position in the Company's 2020 general rate case, docket UE 374 (2020 Rate Case).[12] The Alliance of Western Energy Consumers (AWEC) also opposes PacifiCorp's improved modeling by articulating a contradictory position. In the rate case, AWEC opposed changes to the PCAM by arguing that if PacifiCorp under-recovers its NPC, "the problem almost surely lies in its power cost model."[13] Now that PacifiCorp has proposed to improve the model, AWEC argues that if PacifiCorp under-recovers its NPC, it "does not appear to be due to modeling."[14] The Commission must reject such contradictions and affirm its conclusions reached just last year in PacifiCorp's 2020 Rate Case. The Company's proposed market caps better approximate actual sales opportunities and therefore mitigate the potential for future under-recovery.

Not only do parties oppose modeling improvements designed to mitigate historical NPC under-forecasting, but parties also propose their own adjustments that will potentially increase PacifiCorp's under-recovery by imputing benefits (e.g., the Nodal Pricing Model (NPM) and Other Revenues adjustments) or selectively disallowing discrete cost items without considering the overall reasonableness of the expense and offsetting factors. Indeed, Staff concedes that its adjustments do not even consider PacifiCorp's historical NPC under-recovery.[15] Meanwhile, Staff

[10] *In re PacifiCorp, dba Pac. Power Request for a Gen. Rate Revision*, Docket No. UE 374, Order No. 20-473 at 130 (Dec. 18, 2020).
[11] Staff/800, Dlouhy/35-36.
[12] PAC/1603 at 5.
[13] PAC/1612 at 9.
[14] AWEC/100, Mullins/15-16.
[15] PAC/1600 at 12 (Staff Response to PacifiCorp Data Request 8(b)).

inconsistently proposes adjustments that decrease NPC based on the historical over-recovery of specific line items.[16]

PacifiCorp's positions on the key issues demonstrate that the Commission should approve the TAM as presented:

- The Company has used market caps based on a maximum-of-averages calculation since 2013. In each year, the TAM has over-estimated off-system sales, and the variances have been increasing. PacifiCorp's proposal to restore average-of-average market caps (used in the 2012 TAM and in all other PacifiCorp states) reduces off-system sales volume by approximately 16 percent (or 1.4 million megawatt-hours (MWh)). PacifiCorp's revised market caps will incrementally moderate the gross over-estimation of sales and the resulting NPC under-recovery in the TAM. The alternative market caps proposed by Staff, AWEC, and the Oregon Citizens' Utility Board (CUB) are all insufficient half-measures that will do little to curb the persistent over-forecasting of off-system sales.

- AWEC recommends that the Commission include revenues earned from the sales of fly-ash in the TAM as "Other Revenues."[17] The Other Revenues included in the TAM are identified explicitly in the Commission's precedent and in the TAM Guidelines and do not include fly-ash sales revenue. The Commission previously rejected attempts to impute additional revenues into the TAM because it would fundamentally revise the TAM process. Additional revenues can be included in the TAM only by modifying the TAM Guidelines, which must occur in a rate case. AWEC's adjustment is therefore contrary to well-established Commission precedent and procedurally improper. While Staff testifies that the Company must comply with the TAM Guidelines,[18] it supports AWEC's fly-ash recommendation directly contradicting those guidelines.[19]

- Staff recommends imputing $2.2 million of benefits into the 2022 TAM from PacifiCorp's transition to NPM.[20] As contemplated in the 2020 Inter-Jurisdictional Allocation Protocol (2020 Protocol), NPM primarily allows PacifiCorp to improve NPC tracking for purposes of interstate allocation, but that allocation process is a framework issue in the Multi-State Process that the Company is working on with stakeholders. Instead, the benefits currently provided by NPM result from PacifiCorp's receipt of a more accurate day-ahead dispatch schedule from the California Independent System Operator (CAISO). A more accurate day-ahead schedule should reduce costs the Company incurs *in actual operations* because of the differences between the day-ahead schedule and real-time dispatch. But the

[16] *See, e.g.*, Staff/500, Zarate/12-14 (imputing a $1.53 million adjustment to future QF costs in the 2022 TAM due to historical overestimations).
[17] AWEC/100, Mullins/21.
[18] Staff/100, Enright/19.
[19] Staff/1000, Enright/11.
[20] Staff/900, Gibbens/12.

Generation and Regulation Initiative Decision Tool (GRID) does not include costs incurred based on the differences between day-ahead schedules and real-time dispatch because GRID balances the system in a single step with perfect foresight. Staff is therefore removing costs from GRID that have never been included in GRID. The benefits provided by NPM will make actual operations more like GRID's perfect optimization forecast, just like the intra-regional EIM benefits that the Commission concluded are already embedded in the GRID forecast.

- Staff recommends a reduction to qualified facility (QF) expenses of $1.53 million because Staff claims that the Company has historically over-forecast QF generation, which has harmed customers because of inflated avoided cost prices.[21] Therefore, Staff adjusted the forward-looking QF forecast down to make up for the historical over-forecast. Staff's adjustment appears results-oriented and intended to decrease the NPC forecast because Staff rejects the use of the forecasting methodology for QF contracts that it supports for non-QF resources. Staff also unreasonably singles out a single line-item for a true-up based on historical over-recovery of costs while ignoring the Company's historical under-recovery of other costs, which Staff concedes it does not consider because the TAM is forward-looking.[22]

- The TAM is designed to forecast the Company's actual NPC as accurately as possible. Nonetheless, the parties' ever-expanding proposals around coal modeling—including economic cycling, the use of average costs instead of incremental costs, and ignoring or discounting minimum take provisions—undermine this goal. PacifiCorp has achieved significant reductions in coal generation while maintaining reliability by reducing minimum operating levels and using the added flexibility to integrate renewable generation. On-line resource displacement is necessary for renewable integration, which PacifiCorp cannot accomplish with resources that it must cycle off.

- The Company's five new Coal Supply Agreements (CSAs) for the Hunter, Dave Johnston, and Craig plants are prudent. The new CSAs reflect a reasonable balance of price, volume, and term that allow the Company to adjust to changing market dynamics while including reasonable minimum take levels to ensure a reliable fuel supply. The CSAs reflect minimum take levels consistent with standard industry practices and based on robust economic analysis. Despite Staff's unsupported claims, opportunities for economic cycling are limited and will not materially reduce the forecast generation at any of the three plants with new CSAs. Indeed, there is no evidence that economic cycling will have a material impact on the NPC at any plant or across the Company's coal fleet. Minimum take provisions should be accounted for in calculating NPC because, as the Commission has previously recognized, they are required to secure cost-effective coal supplies.

[21] Staff/500, Zarate/13-14.
[22] PAC/1600 at 12 (Staff Response to PacifiCorp Data Request 8(b)).

Therefore, Staff's recommendation to ignore the minimum take obligation in the new CSAs in future TAMs is unreasonable.

- For short-term forecasts like the TAM, the Company does not use average price as a dispatch price because the cost of coal in a take-or-pay volume tier is not avoidable. Incremental cost dispatch ensures that customers get the benefits of the contracted fuel supply and reduces costs; the Company dispatches all of its resources on an incremental cost basis in determining NPC. Many of Sierra Club's recommendations, including using average cost in dispatch of the Company's coal fleet, the calculation of the Company's Bridger Coal Company (BCC) costs, and the Jim Bridger adjustment, distort the Company-provided data by ignoring fixed costs—against basic economic principles.

- AWEC proposes a $1.18 million adjustment to BCC materials and supplies based on historical over-estimations of this line item.[23] AWEC does not dispute that there are offsetting line items that have historically been under-estimated that nearly eliminated its adjustment. Further, AWEC does not deny that PacifiCorp has forecast overall BCC costs within one percent of actuals in the last five years. Finally, AWEC does not dispute that materials and supplies appeared over-estimated because AWEC applies the full materials and supplies costs to coal production even though the costs covered include reclamation activities.

- PacifiCorp should not be required to file its CSAs or provide copies to the parties in future TAM filings. The existing Modified Protective Order allows parties reasonable access to the CSAs, including the opportunity to make copies of relevant pages. No party has explained why that level of access is insufficient, especially given the extreme commercial sensitivity of the Company's CSAs.

- Calpine Energy Solutions, LLC (Calpine) recommends that the Commission approve a Customer Opt-Out Charge (COOC) that would require cost-of-service customers to pay direct access customers that leave PacifiCorp's system. When PacifiCorp proposed the COOC, it never intended the charge to become a credit paid by customers. Therefore, the COOC should not be allowed to go below zero to mitigate the risk of unwarranted cost-shifting.

- CUB and Staff propose earlier filing dates for the 2023 TAM based on PacifiCorp's upcoming switch to the Aurora modeling system. While PacifiCorp is open to this proposal, it also plans to conduct detailed workshops on the Company's Aurora model in anticipation of the 2023 TAM. Moving up the filing date will not help parties as much as the Company's ability to work with interested parties in these workshops, before or after the filing.

[23] AWEC/200, Mullins/23.

II. ARGUMENT

A. The Commission should approve average-of-averages market caps for use in the 2022 TAM.

As the Commission has recognized, market caps are intended to help the GRID model simulate real-world conditions by putting meaningful limitations on PacifiCorp's ability to sell power into illiquid market hubs.[24] To better reflect actual system operations and mitigate the chronic overstatement of off-system sales in its NPC forecasts, PacifiCorp has proposed replacing the current "maximum-of-averages" market cap methodology with the "average-of-averages" approach it has used in all other jurisdictions for many years.[25] This change reduces off-system sales volume by approximately 16 percent (or 1.4 million MWh total company) in this case,[26] which is a small fraction of the sales over-forecast PacifiCorp has experienced since the Commission adopted the maximum-of-averages approach in 2012. For example, in the last three years, PacifiCorp's forecast off-system sales have been an average of 60 percent higher than its actual sales volumes and persist as the most significant driver of its NPC under-recovery.[27]

Staff, AWEC, and CUB oppose this change, largely ignoring years of data demonstrating the ineffectiveness of market caps based on the maximum-of-averages method. As alternatives to the average-of-averages method, Staff proposes a "third quartile of averages approach";[28] AWEC proposes a complex, iterative market cap methodology;[29] and CUB proposes a revised

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[24] *See, e.g.*, *In re PacifiCorp dba Pac. Power, 2013 Transition Adjustment Mechanism*, Docket No. UE 245, Order No. 12-409 at 7 (Oct. 29, 2012) (acknowledging that market caps "account [for] critical inputs" such as "market illiquidity") [hereinafter 2013 TAM]; *In re PacifiCorp, dba Pac. Power, 2016 Transition Adjustment Mechanism*, Docket No. UE 296, Order No. 15-394 at 3 (Dec. 11, 2015) (highlighting the Company's argument that one reason for market caps is to prevent "artificially increasing sales to illiquid market hubs") [hereinafter 2016 TAM].
[25] PAC/100, Webb/11-12.
[26] Evidentiary Hearing Transcript 266:1-3 (Aug. 26, 2021) [hereinafter Evid. Tr]; Confidential Evid. Tr. 40:16-41:2.
[27] PAC/1605 at 2 (*In re PacifiCorp, dba Pac. Power, 2018 Power Cost Adjustment Mechanism*, Docket No. UE 361, Order No. 19-415 (Nov. 25, 2019) (main deviation leading to a $19.1 million under-recovery in power costs was a decrease in wholesale sales revenues relative to forecast, with actual sales volumes 46 percent less than forecast)); PAC/1606 at 2 (*In re PacifiCorp, dba Pac. Power, 2019 Power Cost Adjustment Mechanism,* Docket No. UE 379, Order No. 20-489 (Dec. 29, 2020) (main deviation leading to a $45.1 million under-recovery in power costs was a decrease in wholesale sales revenues relative to forecast, with actual off-system sales volumes 68 percent less than forecast)); PAC/1607 at 1, 5, *In re PacifiCorp, dba Pac. Power, 2020 Power Cost Adjustment Mechanism,* Docket UE 392, Initial Filing (May 17, 2021) (sales volumes were 66 percent lower than forecast, leading to an NPC under-recovery in 2020 of $29.5 million)).
[28] Staff/1200, Dlouhy/2-3.
[29] AWEC/200, Mullins/17.

methodology similar to Staff's "third quartile of averages" approach.[30] These alternatives are all insufficient half-measures which fail to recognize that, even under average-of-averages market caps, PacifiCorp is likely to continue to forecast more off-system sales than it can achieve in actual operations.

1. Background

PacifiCorp's GRID model operates with perfect foresight and assumes unlimited market depth and full liquidity for the markets in which PacifiCorp makes off-system sales—Mid-Columbia (Mid-C), Palo Verde, California-Oregon Border (COB), Four Corners, Mona, and Mead.[31] GRID does not consider load requirements, transmission constraints, or static assumptions about market prices when modeling off-system sales.[32] GRID thus allows unlimited off-system sales at every market at any time of the day or night—an assumption that is very different from PacifiCorp's actual, historical experience.

To more realistically model actual market conditions, PacifiCorp has included market caps for sales since it introduced the GRID model in 2002.[33] PacifiCorp originally modeled market caps in graveyard hours only. In the 2012 TAM, docket UE 227, PacifiCorp refined its market caps to specify market depth for sales during all hours based on historical average sales from the most recent 48-month period for each trading hub, each month, segregated by heavy-load hour (HLH) and light-load hour (LLH) periods.[34] This refined approach, known as the "average of averages" method, allowed for additional sales and reduced NPC compared to PacifiCorp's original graveyard market caps. At PacifiCorp's suggestion, the Commission adopted the average-of-averages approach in docket UE 227 on a non-precedential basis to allow an opportunity for additional review.[35]

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[30] CUB/200, Jenks/2-3.
[31] PAC/400, Staples/17-18.
[32] PAC/400, Staples/18.
[33] 2013 TAM, Order No. 12-409 at 3-4. PacifiCorp currently includes market caps at the COB, Four Corners, Palo Verde, and Mona market hubs.
[34] *In re PacifiCorp, dba Pac. Power, 2012 Transition Adjustment Mechanism*, Docket No. UE 227, Order No. 11-435 at 21 (Nov. 4, 2011) [hereinafter 2012 TAM].
[35] 2012 TAM, Order No. 11-435 at 23.

In the 2013 TAM, docket UE 245, the Industrial Customers of Northwest Utilities (ICNU, now AWEC) and Staff argued for elimination of market caps, a position the Commission rejected:[36]

> As Pacific Power observes, market caps have always been part of GRID and neither Staff nor ICNU persuasively argue that GRID, as it currently exists, no longer needs market caps. Based upon the evidence presented in this proceeding, we conclude that some form of market caps continue to be needed in GRID as it is now constructed. [37]

At the same time, the Commission accepted Staff's and ICNU's argument that the average-of-averages market cap methodology "overstates expected NPC."[38] Thus, the Commission adopted Staff's "alternative recommendation that essentially split the difference between the company's approach and Staff's recommended no cap approach."[39] This alternative methodology, referred to as the "maximum-of-averages" approach, sets "market caps on the highest of the four most recently available relevant averages for each trading hub, each month, and differentiated by on- and off-peak hours."[40]

The Company does not apply market caps to Palo Verde (by far its largest trading hub)[41] or Mid-C because these hubs are liquid markets. Under the maximum-of-averages approach, the Company must use the most extreme outlier cap value supported by the historical record for every other market hub, resulting in sales that consistently exceed historical averages. This approach contrasts 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.

The Commission adopted a PCAM for PacifiCorp in 2012.[42] Every year since then, the Company has filed actual NPC data to allow the Commission to determine both the variance from

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[36] 2013 TAM, Order 12-409 at 5-8.
[37] 2013 TAM, Order No. 12-409 at 7.
[38] *In re PacifiCorp, dba Pac. Power, 2013 Transition Adjustment Mechanism*, Docket No. UE 245, Order No. 13-008 at 1-2 (Jan. 15, 2013) (denying motion for reconsideration).
[39] Order No. 13-008 at 1.
[40] 2013 TAM, Order No. 12-409 at 7-8.
[41] Staff/800, Dlouhy/27, Table 1.
[42] *In re PacifiCorp, dba Pac. Power, Request for a Gen. Rate Revision*, Docket UE 246, Order No. 12-493 (Dec. 20, 2012).

forecast NPC and whether this variance triggers a rate change. In PacifiCorp's 2020 Rate Case, docket UE 374, PacifiCorp sought changes to its PCAM. In response, Staff filed testimony analyzing PacifiCorp's NPC under-recovery between 2017-2019, relying on PacifiCorp's past PCAM filings.[43] Referring to two market transaction types, purchases and sales, Staff concluded that only one was "largely inaccurate in the forecast."[44] Staff testified that a "gross over-estimation of the sales benefit" was "apparent in both the dollar and MWh metrics."[45]

In its final order in docket UE 374, the Commission invited PacifiCorp to propose modeling changes in the TAM to increase its NPC forecast accuracy specifically concerning off-system sales:

> 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 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. [46]

The Commission issued its order in docket UE 374 on December 18, 2020. On March 3, 2020, in compliance with the TAM Guidelines, PacifiCorp provided the following notice to the parties:

> The Company's GRID model will base wholesale sales market caps on the four-year historical average of short-term firm, balancing and spot sales instead of the highest of the four most recently available relevant averages for each trading hub and each month, differentiated by on- and off-peak hours. This will be done in order to improve forecast accuracy and to address the Commission's concern noted on page 130 of Order 20-473 (Docket No. UE 374) regarding the overestimation of the Company's wholesale sales revenue.[47]

[43] PAC/1603 at 2-5 (Docket No. UE 374, Staff/2400, Gibbens/19-22).
[44] PAC/1603 at 5.
[45] PAC/1603 at 5.
[46] Order No. 20-473 at 130 (footnotes omitted).
[47] PacifiCorp's Notice of Methodology Changes in the 2022 TAM, Docket UE 375 (Mar. 1, 2021).

2. Maximum-of-averages market caps forecast off-system sales that greatly exceed actual sales; averages-of-averages market caps will mitigate this over-estimation.

In 2012, using average-of-averages market caps, PacifiCorp over-estimated off-system sales by 1.6 million MWh total company.[48] When PacifiCorp applied the maximum-of-averages market caps for the first time in 2013, its sales over-estimate more than doubled to 3.7 million MWh total company.[49]

The Company's approved PCAM filings demonstrate that the Company's sales over-estimation has continued to grow steadily since 2013, most recently topping 9.0 million MWh total company—or $249 million total company in overstated revenue credits—in 2020.[50] PacifiCorp's PCAM filings from 2013-2020 reflect a cumulative over-estimate of $1.55 billion total company in off-system sales revenues[51] and a concomitant, chronic understatement of NPC.[52]

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 HLH and LLH. 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. Thus, when the Commission adopted the maximum-of-averages approach over the average-of-averages approach in 2012, the Commission was not rejecting the basic methodology of the average-of-averages approach. Instead, out of concern that overly-restrictive market caps could overstate NPC, the Commission adopted the maximum-of-averages iteration, splitting the difference between the average-of-averages approach and eliminating market caps altogether.[53]

Eight years later, the data clearly demonstrates that the average-of-averages approach will not overstate NPC. First, PacifiCorp does not apply market caps to two of its liquid trading hubs,

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[48] PAC/400, Staples/23 (Figure 4).
[49] PAC/400, Staples/23 (Figure 4).
[50] PAC/400, Staples/23 (Figure 4).
[51] PAC/400, Staples/24 (Figure 5).
[52] PAC/400, Staples/14 (Figure 2).
[53] 2013 TAM, Order No. 13-008 at 2.

including Palo Verde, where the Company has made almost six times as many sales compared to other hubs.[54] Second, the average-of-averages approach reduces sales by approximately 16 percent or 1.4 million MWh total company in this case, which is likely to make only a modest dent in the Company's gross over-estimation of sales. For example, applying this decrement to PacifiCorp's actual 2020 NPC reduces the over-estimation in sales from approximately 9 million MWh total company to approximately 7.4 million MWh total company. Third, while employing the average-of-averages approach mitigates the over-estimation of sales, the change in allowed sales remains small enough not to drive a major change in NPC results. In this case, the shift to average-of-averages market caps increases NPC by approximately $5 million. Again, looking to PacifiCorp's actual 2020 NPC as an example, this increment would reduce PacifiCorp's NPC under-recovery from $28.2 million to $23.2 million.

3. The Company's transition to the Aurora model for the 2023 TAM should not preclude the adoption of average-of-averages market caps in this case.

Staff and AWEC argue against changing the market cap methodology because PacifiCorp plans to use the Aurora dispatch model for the 2023 TAM.[55] The TAM is a one-year forecast to ensure accurate NPC forecasting for the next year. There is no basis for perpetuating a persistent and significant forecast error in 2022 because the Aurora model may change the forecast in some way in the next year. PacifiCorp has been clear that, as with any dispatch model it deploys, Aurora will need market caps to control sales at non-liquid hubs.[56]

Last year, when AWEC expected PacifiCorp to transition to Aurora for this TAM, AWEC proposed multiple modeling adjustments, including a complex $8.2 million adjustment to the Day-Ahead/Real-Time (DA/RT) adjustment.[57] This year, under the same circumstances, AWEC now urges the Commission to reject PacifiCorp's market cap proposal because of GRID's planned

[54] Staff/800, Dlouhy/27, Table 1.
[55] AWEC/200, Mullins/5; Staff/800, Dlouhy/31.
[56] *See* PAC/400, Staples/21 ("AURORA represents a meaningful improvement to the Company's modeling capabilities, but it is not so robust as to produce valid results without a realistic set of constraints to reflect the normal conditions under which the Company operates.").
[57] PAC/1608 at 4 (Docket No. UE 375, AWEC/100, Mullins/2).

replacement. Just as AWEC did in the 2021 TAM, PacifiCorp should be free to propose changes to NPC modeling in the 2022 TAM, especially when directed to do so by the Commission, irrespective of the upcoming transition to Aurora.

4. In assessing the need for revised market caps, the Commission should rely on audited and approved PCAM data and reject the use of non-comparable data.

In support of the "maximum of averages" approach, AWEC claims that the current market cap approach does not over-estimate sales when adjusted for bookouts.[58] Staff makes a similar claim based on its analysis of total wholesale sales data, including bookouts.[59] PacifiCorp uses bookouts when it holds offsetting positions for sale and purchase at the same delivery point, in the same hour, with the same counterparty.[60] GRID has never accounted for the possibility of bookouts in its NPC modeling because sales and purchase prices are optimized and never offsetting. Thus, bookouts are not modeled in normalized NPC.[61]

The introduction of arguments based on bookouts ignores the reality that the Commission has audited the variances between forecast and actual NPC since 2013. After this review, the Commission has approved each of the Company's PCAM filings as compliant, periodically directing that PacifiCorp include specific additional information in these filings. At no time has any party ever suggested that PacifiCorp's actual NPC filed in the PCAM dockets is inaccurate because it does not account for bookout transactions. Because the GRID forecast omits bookout transactions, including them in the Company's actual NPC filed in the PCAM would be objectionable because it is non-comparable data.

In PacifiCorp's 2020 Rate Case, Staff relied on the Company's PCAM data in determining that PacifiCorp's NPC forecasts contained a gross over-estimate of off-system sales. Staff has not

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[58] AWEC/200, Mullins/12-13.
[59] Staff/800, Dlouhy/35-36.
[60] PAC/400, Staples/25 n.60.
[61] PAC/400, Staples/25; *see also* 2013 TAM, Order No. 12-409 at 5 (discussing PacifiCorp's argument that a comparison of historical averages inclusive of bookouts against a GRID model exclusive of bookouts is like comparing "apples and oranges").

articulated any basis for questioning the PCAM data this year other than the fact that it does not reflect all wholesale sales, only those comparable to the sales forecast in GRID.

AWEC argues that certain sales forecast in GRID (i.e., the Public Service Company of Colorado (PSCo) Exchange and many transactions included in the DA/RT adjustment) resemble bookout transactions and justify a comparison to actual NPC volumes including bookouts.[62] In response, the Company showed that even after removing these alleged bookouts from the forecast, GRID still over-forecasted sales by an average of approximately 4.2 million MWh total company per year.[63] In comparison, PacifiCorp's proposed market cap change results in a 1.4 million MWh total-company reduction in sales,[64] or one-third of the average over-estimation, even after accounting for the DA/RT adjustment and the PSCo Exchange. This validates the results consistently shown in the Company's audited and approved PCAM filings, which points to sales over-estimation as a major and persistent forecast error.

5. Staff incorrectly interprets the Commission's past orders as precluding average-of-averages market caps.

While Staff acknowledges that "it is possible that the current 'maximum of averages' approach is not the optimal method for forecasting off-system sales,"[65] it still maintains that the Commission should not adopt PacifiCorp's proposed methodology. Staff argues that Order No. 12-409 in the 2013 TAM determined that the average-of-averages approach was "problematic" and rejected the approach outright.[66] As explained above, however, the only position the Commission rejected outright was the argument that market caps should be completely eliminated.[67] The Commission made clear that it adopted the maximum-of-averages approach to allow additional sales volumes, not because the average-of-averages approach was fundamentally flawed or unreasonable.[68]

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[62] AWEC/200, Mullins/10-11.
[63] PAC/1000, Staples/34 (Confidential Figure 3).
[64] PAC/1000, Staples/34.
[65] Staff/1200, Dlouhy/12.
[66] Staff/1200, Dlouhy/6.
[67] 2013 TAM, Order No. 12-409 at 7.
[68] *See* 2013 TAM, Order No. 12-409 at 7-8.

In Order No. 20-473, the Commission signaled a willingness to expeditiously consider new adjustments or limitations to address the gross over-estimation of sales in TAM forecasts. The Company's proposal to return to average-of-averages market caps reasonably responds to Order No. 20-473 because (1) the same methodology underlies current market caps and the average-of-averages approach, which makes it straightforward to analyze and implement; (2) the Company used average-of-averages market caps previously in Oregon and currently uses it in all other states; (3) the average-of-averages approach produces a relatively small change in forecast sales and overall NPC, but still represent a material step toward greater forecast accuracy.

6. None of the parties' alternative proposals meaningfully address the current gross overestimation of sales.

Conceding that the maximum-of-averages approach may be sub-optimal, Staff has proposed a "third quartile of averages" approach as a potential alternative methodology. Staff's proposed approach is one more iteration of PacifiCorp's average-of-averages approach, this time setting the cap as the average of the highest and second-highest averages at each hub.[69] Similarly, CUB acknowledges that the current market cap approach "has proven itself to be too expansive"[70] but still contends that the Company's proposal is "too restrictive."[71] CUB proposes splitting the difference and using the mid-point between the "average of averages" and "maximum of averages" approach.[72] While the proposals from Staff and CUB are straightforward and build on similar methodologies, neither will effectively end the gross over-estimation of sales in the TAM because both proposals are designed to allow more sales than PacifiCorp's average-of-averages approach. PacifiCorp has shown that even its average-of-averages approach will not fully solve the problem of sales over-estimations. Therefore, by definition, any proposal that would have a smaller impact on the sales forecast will be less accurate.[73]

[69] Staff/1200, Dlouhy/14.
[70] CUB/200, Jenks/11.
[71] CUB/200, Jenks/11.
[72] CUB/200, Jenks/11-12.
[73] PAC/1000, Staples/51.

Even though AWEC has spent much of this proceeding arguing that GRID's market caps should remain the same, it has conceded that the model does overestimate sales at the COB and Four Corners market hubs.[74] To remedy these specific issues at specific market hubs, AWEC proposes setting the market cap through iterative GRID runs so that the model produces results that equal, but do not exceed, the historical average. While the approach attempts to remedy the over-estimation of sales at COB and Four Corners, the complicated nature of the proposal—which AWEC did not present until the final round of testimony—may present implementation challenges in the 2022 TAM.[75] Additionally, AWEC's adjustment is intended to produce a sales forecast that resembles the historical sales levels experienced by the Company in its actual operations.[76] The purpose of the market cap calculation in GRID is to set limits on GRID's sales activity, but to ultimately allow the model to determine the most appropriate sales outlook for the test period.[77] In proposing a methodology that would produce a sales forecast that would equal but not exceed the 48-month average, AWEC's proposal goes beyond setting limits in GRID and functionally dictates an outcome to the model, as opposed to providing a limit but allowing the model to determine the optimal outcome within the confines of that limit.

B. Both Commission precedent and the TAM Guidelines preclude AWEC's Other Revenues adjustment.

In PacifiCorp's 2020 Rate Case, the Commission included $4.2 million of fly-ash revenues in base rates. To capture a recent increase in these revenues in this stand-alone TAM, AWEC has proposed to update fly-ash sales revenue in TAM Other Revenues,[78] and Staff has supported the adjustment. This proposal is contrary to Commission precedent, contrary to the TAM Guidelines, improperly one-sided, and unsupported in the record.

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[74] AWEC/200, Mullins/17. AWEC also contends that GRID underestimates sales at Mead due to transmission constraints. *Id.*
[75] PAC/1000, Staples/36-37.
[76] AWEC/200, Mullins/17.
[77] PAC/100, Webb/10.
[78] AWEC/100, Mullins/20; Staff/1000, Enright/11.

1. Revenue is included in the TAM only if Order No. 10-363 specifically identified the revenue source.

In the 2008 TAM, ICNU argued that certain revenue related to PacifiCorp's contract with Georgia Pacific (GP) Camas should be included in the TAM as a reduction to NPC even though the offsets were in an "Other Revenues" account.[79] The Commission rejected ICNU's adjustment because it was "outside the scope of the TAM proceeding."[80] The Commission explained that it "did not intend that the TAM procedure would encompass such factors as contract 'offsets' that are better suited to the general rate case, along with other issues relating to capital cost recovery and major maintenance."[81]

In 2009, the Commission adopted the TAM Guidelines as the agreed-upon parameters for TAM proceedings.[82] The Guidelines make clear that because the purpose of the TAM is to update NPC (as defined by specific Federal Energy Regulatory Commission (FERC) accounts), revenues are outside of the scope of the TAM unless specifically stated. The original TAM Guidelines specified that only one revenue item could be included in a stand-alone TAM filing, Little Mountain steam sales:

> The Initial Filing will include updates to all of the net power cost components identified in Attachment A to the Stipulation (specified FERC accounts for net power costs). These costs will be based on the Company's most recent official forward price curve, forecast load and allocation factors. In a stand-alone TAM filing the Company also will update the steam revenues associated with Little Mountain steam sales. When a TAM is filed in, or processed concurrently with, a general rate case, this element may be included in the TAM or in the general rate case.[83]

In 2010, as part of a stipulated settlement in the 2011 TAM, docket UE 216, the parties agreed to include a new line item in future stand-alone TAM filings for forecasted changes to

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[79] *In re PacifiCorp, dba Pac. Power, 2008 Transition Adjustment Mechanism*, Docket No. UE 191, Order No. 07-446 at 21 (Oct. 17, 2007) [hereinafter 2008 TAM].
[80] 2008 TAM, Order No. 07-446 at 22.
[81] 2008 TAM, Order No. 07-446 at 22.
[82] *In re PacifiCorp, dba Pac. Power, 2009 Transition Adjustment Mechanism Schedule 200, Cost-Based Supply Service*, Docket No. UE 199, Order No. 09-274 (July 16, 2009) [hereinafter TAM Guidelines].
[83] TAM Guidelines, Order No. 09-274 at 3.

"Other Revenues."[84] This line item only included revenues that "have a direct relation to NPC" and "for which a revenue baseline has been established" in the Company's 2010 general rate case, docket UE 217.[85] The stipulation contained five separate items that had revenue baselines established in docket UE 217: the storage and exchange agreements for the Seattle City Light Stateline and Foote Creek projects; revenues from the Bonneville Power Administration associated with the South Idaho Exchange, steam revenues for Little Mountain, and royalty revenues for the GP Camas contract.[86] Neither the stipulation nor the joint testimony accompanying the stipulation contained any further revenue streams associated with the Other Revenues line item.[87] The Commission approved the stipulation without modification in Order No. 10-363. Notably, the revenues from the GP Camas contract—previously rejected for inclusion in the 2008 TAM—were now included in Other Revenues but only because the stipulated change to the TAM Guidelines specifically identified the GP Camas contract for inclusion.

Since the 2011 TAM, PacifiCorp has updated Other Revenues in all stand-alone TAM filings based on the specific revenue items listed in Order No. 10-363, the last of which will terminate in 2021.[88] The Commission has never recognized additional Other Revenues items in the TAM and has rejected attempts to include revenue items not specified in the TAM Guidelines.[89] Most notably, in the 2012 TAM, ICNU sought to include updated retail sales revenue in the TAM.[90] In that case, the Commission rejected ICNU's imputation of revenue. The Commission explained that the TAM Guidelines "make[] clear that the TAM filing focuses on the NPC side of the equation" and that "[n]othing in our prior orders or approved guidelines suggests

[84] *In re PacifiCorp, dba Pac. Power, 2011 Transition Adjustment Mechanism*, Docket No. UE 216, Order No. 10-363 at 3 (Sept. 16, 2010) [hereinafter 2011 TAM].
[85] 2011 TAM, Order No. 10-363, App'x A at 4.
[86] 2011 TAM, Order No. 10-363, App'x A at 4.
[87] PAC/1610 at 11 (Docket No. UE 216, Joint/100, Page 9).
[88] The Company mistakenly included revenues from the Stateline contract in its initial filing even though the contract has been terminated. The Company corrected this error in the reply update, increasing the 2022 TAM by approximately $3 million. *See* PAC/400, Staples/93.
[89] *See, e.g.*, 2012 TAM, Order No. 11-435 at 6 ("Nothing in [the Commission's] prior orders or approved guidelines suggest[] that an adjustment to the revenue side is within the scope of the TAM."); Evid. Tr. 193:25-194:10 (admitting that AWEC has never attempted to include fly-ash sales in Other Revenues in previous TAM proceedings).
[90] 2012 TAM, Order No. 11-435 at 6.

that an adjustment to the revenue side is within the scope of a TAM."[91] The Commission found that ICNU was "advocating a fundamental revision to the TAM process itself" and noted: "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."[92]

2. Fly-ash sale revenues are currently included in base rates and have never been included in the TAM.

Revenues from fly-ash sales are not specifically identified in Order No. 10-363 as an Other Revenues item that can be updated as part of a stand-alone TAM proceeding, nor is the account where fly-ash sales revenue is booked, FERC account 456, included in the TAM.[93] Fly-ash revenues have been in base rates since at least the 2011 TAM when the Commission adopted the Other Revenues line item in the TAM Guidelines. No party has previously proposed to update fly-ash sales revenue in a stand-alone TAM, and the Commission has never approved such an update.[94] Had the parties intended to include fly-ash sales revenue in the TAM, they could have included it in the 2011 TAM stipulation—but they did not. Therefore, like ICNU's retail revenue adjustment, fly-ash sales revenue is outside the scope of a stand-alone TAM.

Moreover, fly-ash sales revenue is not well suited for inclusion in the TAM. Staff first proposed the Other Revenues line item in the 2011 TAM to include corresponding revenues associated with certain costs already included in the TAM to appropriately match costs and benefits:

> In non-general rate case years, in which only a power cost update is filed, the Company is allowed to include or update costs associated with new resources, contracts and existing facilities for services that it is providing to a third party entity. With the update or inclusion of these costs there can also be a corresponding change in revenue. If these revenues are accounted for as "other revenue" they currently

[91] 2012 TAM, Order No. 11-435 at 6.
[92] 2012 TAM, Order No. 11-435 at 6.
[93] PAC/1000, Staples/55.
[94] *See* Evid. Tr. 193:25-194:10.

go un-recognized in rates. This mismatch between updating costs and revenues is unreasonable.[95]

Staff proposed the Other Revenues line item to match updated costs for services provided to a third-party entity already included in the TAM with revenues it receives for those services, as evidenced by the limited and specific revenue items identified in Order No. 10-363. Coal fly-ash is a byproduct of the Company's coal generation, and revenue generated by its sale is not an offsetting benefit to a cost incurred by PacifiCorp to provide a third-party service.[96]

3. If AWEC wants to include additional revenues in the TAM, it must propose a change to the TAM Guidelines in a general rate case.

The TAM Guidelines are clear and unambiguous—if AWEC wants to include additional sources of revenue in the TAM, "such changes are to be appropriately addressed in a general rate revision docket or other proceeding, *not part of a stand-alone TAM proceeding*."[97] In the Company's 2020 Rate Case, several parties—including AWEC[98]—proposed changes to the TAM Guidelines, but no party sought to expand the TAM to include fly-ash revenues.[99] Indeed, CUB specifically requested that the Commission modify the TAM Guidelines to include wheeling revenue in the TAM.[100] The Commission rejected CUB's recommendation because it would increase PacifiCorp's risk by making wheeling revenue subject to the PCAM deadbands and because the Commission "hesitate[s] to make changes to the [TAM] guidelines absent consensus."[101] AWEC could have proposed to include fly-ash sales revenue in future stand-alone TAMs by including it in the rate case, but chose not to raise this issue in that proceeding. AWEC cannot now use a stand-alone TAM proceeding to modify the TAM Guidelines in contravention of clear Commission precedent.

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[95] PAC/1000, Staples/54-55 (quoting 2011 TAM, Staff/100, Brown/14 (May 12, 2010)).
[96] *See* PAC/1000, Staples/55.
[97] 2012 TAM, Order No. 11-435 at 6 (emphasis added).
[98] PAC/1611 at 6 (Docket No. UE 374, AWEC/100, Mullins/41).
[99] *See* Order No. 20-473 at 128-29 (summarizing the various parties' proposals to change the TAM Guidelines).
[100] Order No. 20-473 at 128.
[101] Order No. 20-473 at 130-31.

4. AWEC's adjustment ignores offsetting expenses that PacifiCorp incurs to generate fly-ash sales.

While fly-ash production is a benefit of coal generation, other accounts, such as chemical expenditures, represent costs associated with coal generation that the Company incurs to generate the fly-ash that it eventually sells. These additional expenses are included in base rates and updated in general rate cases. Including revenue from fly-ash sales without including all the costs incurred to generate fly-ash violates the matching principle and the rationale for including revenues in the TAM.[102]

AWEC now claims that it is an "unfair result" to exclude fly-ash sales revenues because sales have fluctuated since the 2020 Rate Case.[103] This argument is unpersuasive. First, AWEC could have requested a change to the TAM Guidelines in the 2020 Rate Case. AWEC did not. Second, many costs and revenues have fluctuated since the 2020 Rate Case, but they are not included in the TAM. Indeed, ICNU justified its retail revenue adjustment on the same basis that it was unfair for changes in retail load to increase NPC in the TAM without an offsetting revenue credit—to no avail.[104]

5. AWEC's adjustment is unsupported in the record.

Even if the TAM Guidelines and Commission precedent authorized AWEC's adjustment, the record insufficiently supports the imputation of fly-ash sales revenue. First, AWEC's citation to the TAM Guidelines in its testimony was incomplete and misleading, quoting only the language that the Other Revenues item must be related to NPC and omitting the language identifying the agreed-to revenue items.[105]

Second, throughout this proceeding, AWEC's adjustment has been in flux. Initially, AWEC proposed its adjustment based on the fly-ash sales PacifiCorp reported in its FERC Form

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[102] *See, e.g.*, ORS 757.259(2)(e) (authorizing deferrals "to match appropriately the costs borne by and benefits received by ratepayers"); *In re Pub. Util. Comm'n of Or. Investigation of Automatic Adjustment Clause Pursuant to SB 838*, Docket No. UM 1330, Order No. 07-572 at 5 (Dec. 19, 2007) (renewable adjustment clause designed to match costs and benefits of renewable resources in rates).
[103] Evid. Tr. 195:16-20.
[104] 2012 TAM, Order No. 11-435 at 6.
[105] Evid. Tr. 190:21-191:19.

1 for 2020, excluding any sales from Cholla to adjust for the plant's retirement[106] and then proposing to include increasing 2021 forecast revenues in the 2022 TAM.[107] AWEC's proposal contains an obvious error that overestimates the proposed adjustment based on PacifiCorp's 2020 fly-ash sales.[108] Specifically, AWEC proposed a $929,973 adjustment based on the difference between fly-ash sales revenue projected in PacifiCorp's 2020 Rate Case and actual 2020 sales.[109] But a simple examination of AWEC's exhibit shows that the actual difference is $595,379.[110]

At hearing, AWEC changed its position and increased its adjustment for the first time based on PacifiCorp's fly-ash sales 2021 revenue projection in the Company's current Idaho Rate Case.[111] Not only is proposing a new adjustment at hearing procedurally improper, AWEC's witness could not even explain the basis for his newfound adjustment and cited the incorrect non-normalized figure from the Company's Idaho filing.[112] AWEC disingenuously justified its increased adjustment because its expert witness claimed that information about a new fly-ash sales contract "came to light . . . kind of recently."[113] But the information AWEC cited was filed by the Company in its Idaho rate case in May 2021—before AWEC filed testimony in the TAM.[114] Because AWEC's witness, Mr. Mullins, is also an expert witness in the Company's Idaho rate case, he presumably knew this information for months in advance of the hearing.[115] As a result, AWEC has failed to meet its burden of production to support reducing this stand-alone TAM for an unrecognized revenue item.[116]

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[106] AWEC/100, Mullins/21.
[107] Evid. Tr. 198:16-21.
[108] *See* Evid. Tr. 204:23-205:9.
[109] AWEC/204, Mullins/1.
[110] *See* AWEC/204, Mullins/1.
[111] Evid. Tr. 198:16-21.
[112] *Compare* Evid. Tr. 198:16-21 *with* AWEC/302 at 4 (citing the non-normalized $15 million dollar figure when the Company's normalized fly-ash sales revenue reported in its 2021 Idaho rate case is $8.9 million).
[113] Evid. Tr. 199:5-6.
[114] AWEC/302 at 3.
[115] *See In re Application of Rocky Mountain Power for Authority to Increase its Rates & Charges in Idaho & Approval of Proposed Elec. Serv. Schedules & Regulations*, Case No. PAC-E-21-07, Petition of PacifiCorp Idaho Industrial Customers for Leave to Intervene at 2 (June 10, 2021) (listing Bradley Mullins as a retained expert witness).
[116] *See* Order No. 20-473 at 5 (describing the burden of production standard).

C. There is no basis for imputing an NPC reduction based on the Nodal Price Model.

As part of the 2020 Protocol, PacifiCorp is transitioning to NPM "to allow states to pursue and be allocated the costs and benefits of different portfolios, while maintaining the benefits of system dispatch as much as practicable."[117] At a high level, NPM consists of two components. First, and most importantly, PacifiCorp will use NPM to track NPC for purposes of interstate allocation.[118] This process is currently under discussion as framework issue in the Multi-State Process, and PacifiCorp does not intend to transition to NPM to track power costs until 2024.[119] Second, NPM will allow PacifiCorp to more efficiently dispatch its resources in actual operations by providing day-ahead schedules from CAISO. Under the contract with CAISO, PacifiCorp pays an $8.4 million annual service fee to CAISO as the third-party vendor to produce day-ahead optimal unit commitment and hourly energy schedules for supply resources in PacifiCorp's Balancing Authority Areas (BAAs) using the CAISO day-ahead market model.[120] As a signatory to the 2020 Protocol and NPM Memorandum of Understanding (MOU), Staff agreed that the pursuit of the NPM was prudent.[121]

While the Company does receive day-ahead schedules from CAISO, which may reduce costs the Company incurs *in actual operations* because of the differences between the day-ahead schedule and real-time dispatch, these benefits simply bring actual operations closer to the perfect foresight of the GRID model.[122] Regardless, Staff has recommended that the Commission reduce total-company NPC by $8.4 million—the entire CAISO service fee—as a "proxy" for asserted benefits the Company presently realizes from a model that the Company has not fully implemented.[123] Alternatively, Staff requests that the Commission direct PacifiCorp to conduct a

[117] *In re PacifiCorp, dba Pac. Power, Request to Initiate an Investigation of Multi-Jurisdictional Issues and Approve an Inter-Jurisdictional Cost Allocation Protocol*, Docket UM 1050, Order No. 20-024 at 8 (Jan. 23, 2020).
[118] PAC/1100, Wilding/2-3.
[119] PAC/400, Staples/76.
[120] PAC/400, Staples/77.
[121] PAC/1100, Wilding/11 (citing Docket No. UM 1050, PAC/101, App'x D (Nodal Price Model Memorandum of Understanding)).
[122] PAC/1100, Wilding/6.
[123] Staff/1300, Gibbens/6.

TAM model run in Aurora using the same inputs as this year's GRID run to assess any differences in the 2022 PCAM.[124] The Commission should reject both of Staff's recommendations because any NPM benefits are already reflected in GRID's NPC forecasts, the Commission has rejected similar proposals in past TAM proceedings, and Staff has produced no evidence establishing that PacifiCorp has received $8.4 million in incremental NPM benefits.

1. Any benefits associated with NPM are already reflected in GRID's optimized forecast and are embedded in actual NPC.

When the parties to the 2020 Protocol—including Staff—approved the adoption of NPM, the primary intention was to track costs and benefits of different resource portfolios for each state.[125] During that proceeding, PacifiCorp was clear that any operational savings resulting from NPM would result from "a more efficient day-ahead set up" and would be "embedded" in NPC.[126] In other words, a more efficient day-ahead setup results in fewer changes between the day-ahead dispatch plan and real-time dispatch, lowering actual NPC.[127] This benefit is impossible to track because PacifiCorp cannot know what the day-ahead set up would be without NPM.[128] All of this was explained in the NPM MOU in docket UM 1050, to which Staff was a party.[129] Neither Staff nor any other party to the 2020 Protocol argued that NPM would also create NPC savings that would be imputed into the TAM.[130]

Now, Staff argues that because GRID uses a zonal topology, it cannot capture the incremental benefits of this more efficient day-ahead setup.[131] For these operational benefits to be incremental, the GRID model would have to include costs associated with changes between the day-ahead setup and real-time dispatch. But the GRID forecast does not include any of these costs because GRID bases its forecast on a single balancing step and a single set of inputs.[132] Essentially,

[124] Staff/1300, Gibbens/6-7.
[125] PAC/1100, Wilding/9.
[126] PAC/1100, Wilding/10 (quoting Docket No. UM 1050, PAC/300, Wilding/10-11).
[127] PAC/1100, Wilding/5.
[128] PAC/1100, Wilding/5.
[129] PAC/1100, Wilding/10.
[130] PAC/1100, Wilding/10.
[131] Staff/1300, Gibbens/3-4.
[132] PAC/1100, Wilding/6.

NPM will reduce *actual* NPC by removing uncertainty between the day-ahead schedules and real-time dispatch. But GRID has no uncertainty between the day-ahead set-up and actual dispatch because the model has perfect foresight and presumes perfect alignment between the day-ahead schedule and actual dispatch.[133] In short, because GRID does not include costs associated with the difference between day-ahead and real-time dispatch, there are no costs to remove from the GRID forecast due to the transition to NPM.

Of course, in actual operations, day-ahead dispatch decisions are inherently imperfect, and human operators are making decisions without GRID's perfect foresight.[134] Therefore, NPM helps bring actual dispatch decisions closer to GRID's forecast by increasing the optimization between day-ahead plans and actual dispatch. Even if NPM perfectly matched day-ahead schedules with actual dispatch every day of the year, it would not provide any better optimization than GRID because GRID already assumes perfect optimization each day. Staff's position boils down to a claim that by receiving more granular day-ahead schedules from CAISO, PacifiCorp's dispatch decisions will now be *more optimized* than the perfect optimization achieved by GRID. Such a claim does not withstand scrutiny, and therefore, imputing incremental NPM dispatch benefits outside GRID is unreasonable.

2. The operational benefits of NPM are comparable to the intra-regional EIM benefits that the Commission concluded are embedded in the NPC forecast.

Staff analogizes its imputed NPM benefits to PacifiCorp's participation in the EIM.[135] Although Staff broadly references EIM benefits in its testimony, the NPM adjustment it proposes is directly analogous to *intra-regional* EIM benefits that the Commission has not imputed as a reduction to NPC. The Commission should follow its past precedent and reject any imputation of NPM benefits as well.

[133] *See* PAC/400, Staples/78.
[134] PAC/400, Staples/78.
[135] Staff/900, Gibbens/12.

In the 2017 TAM, docket UE 307, Staff and CUB recommended an adjustment to impute intra-regional EIM benefits as a separate adjustment outside of GRID.[136] Intra-regional EIM benefits result from the more optimized hourly dispatch of the Company's generation within its BAAs. These benefits differ from *inter-regional* EIM benefits, which result from cost-effective transfers between PacifiCorp and other EIM participants. These inter-regional benefits are included as a separate adjustment outside of GRID.[137] PacifiCorp opposed the imputation of intra-regional EIM benefits because GRID's perfect foresight already dispatches the lowest-cost resources, subject to transmission constraints. Therefore, intra-regional benefits manifest as a decrease in the Company's actual, not modeled, NPC.[138] Put another way, the more efficient dispatch already present in GRID could now be achieved in actual operations. The Commission agreed with PacifiCorp, concluding that the "GRID forecast already accounts for intra-regional benefits because the model optimizes dispatch on an hourly basis."[139]

The parallels between the EIM's intra-regional benefits and NPM are compelling and undisputed. First, NPM uses "similar market features and technology optimization algorithm approaches employed in the EIM."[140] Indeed, Staff's testimony explains that a benefit of NPM is that it "guarantees that the solution outcome is consistent with the CAISO EIM market solution *since it is using the same exact tool and input data*."[141] Second, NPM optimizes resource dispatch *within PacifiCorp's BAAs*, which is identical to the benefits resulting from the EIM's intra-regional benefits.[142] Like intra-regional EIM benefits, the use of NPM to efficiently dispatch resources

[136] *In re PacifiCorp, dba Pac. Power, 2017 Transition Adjustment Mechanism*, Docket No. UE 307, Order No. 16-482 at 15 (Dec. 20, 2016) [hereinafter 2017 TAM].
[137] PAC/400, Staples/79.
[138] *See* 2017 TAM, Order No. 16-482 at 15-16 ("PacifiCorp does not include intra-regional benefits in the TAM because it states that GRID has always reflected perfectly optimized dispatch. . . . PacifiCorp maintains that intra-regional benefits are inherent in the GRID forecast and imputing additional benefits is double-counting . . . PacifiCorp states that the intra-regional benefits are real, but they only bring actual costs closer to the ideal dispatch calculated GRID.").
[139] 2017 TAM, Order No. 16-482 at 16.
[140] 2020 Protocol, App'x D, Ex. A.
[141] Staff/900, Gibbens/9 (emphasis added).
[142] *See* 2020 Protocol, App'x D, Ex. A ("NPM solution" will include PacifiCorp's BAAs in the Day-Ahead Market (DAM) footprint and then using the DAM will produce "optimal unit commitment and hourly energy schedules for supply resources in PACW and PACE.").

within PacifiCorp's BAAs using the same market tools will bring actual NPC closer to the ideal dispatch scenario calculated in GRID.[143] Because these benefits are already embedded in GRID's perfect dispatch, the imputation of additional benefits would result in an improper double-counting of any savings.

3. Staff presents no evidence to show that its $8.4 million adjustment reflects incremental NPM benefits.

In its testimony regarding NPM, Staff acknowledges that any anticipated benefits from NPM are "difficult or impossible" to quantify.[144] Nonetheless, Staff proposes to reduce NPM by $8.4 million total company as a proxy for any alleged benefits accrued from NPM in 2022 without evidence to show that PacifiCorp has achieved any—let alone $8.4 million—incremental NPM benefits.[145]

To support its adjustment, Staff points to the 2015 TAM settlement in which PacifiCorp agreed to offset EIM start-up costs as a proxy for the expected benefits of the EIM.[146] But Staff fails to acknowledge that this agreement was part of a stipulated settlement that did not "imply agreement on the merits of any adjustment" contained in the settlement.[147] In any event, there are two key distinctions between the 2015 TAM settlement on EIM costs and benefits and Staff's NPM adjustment here. First, there was no dispute that the EIM would generate *inter-regional benefits*, which justified an adjustment outside of GRID that formed the basis for offsetting EIM start-up costs. There are no *inter-regional benefits* in the NPM. Second, Staff is a party to the MOU memorializing the NPM agreement, where parties affirmed their support "for PacifiCorp's reasonable and prudent investment of related capital funds, related operations and maintenance expenses, and the related ongoing grid management charges to develop and implement an

[143] PAC/400, Staples/79.
[144] Staff/900, Gibbens/12.
[145] Staff/1300, Gibbens/6.
[146] *In re PacifiCorp, dba Pac. Power 2015 Transition Adjustment Mechanism & Application for Deferred Accounting & Prudence Determination Associated with the Energy Imbalance Market*, Docket Nos. UE 287 & UM 1689, Order No. 14-331, App'x A at 4 (Oct. 1, 2014) [hereinafter 2015 TAM].
[147] 2015 TAM, Order No. 14-331, App'x A at 5.

NPM."[148] Unlike the EIM implementation costs in the 2015 TAM, Staff has already agreed to support recovery of NPM costs in rates—an agreement undermined here by the suggested imputation of illusory, fully offsetting NPC benefits.

4. Staff's alternative proposal to include a 2022 TAM run with Aurora in the 2022 PCAM is based on a faulty premise.

As outlined above, any benefits accrued from NPM are already reflected in the GRID NPC forecast.[149] Thus, the premise that the Company can estimate the benefits of NPM by comparing an Aurora run to a GRID run is false. Because Aurora is an entirely different model than GRID, the variances between a GRID run and an Aurora run could be from any number of modeling differences inherent in the two models.[150] Staff's proposal incorrectly implies otherwise, and it should be rejected.

D. Further adjustments to QF contract modeling are inconsistent with the modeling of other PacifiCorp-owned generation sources and the Company's historical NPC under-recovery.

PacifiCorp forecasts renewable generation at its own facilities and all QF facilities with a nameplate capacity greater than 10 megawatts in the same manner. The Company forecasts capacity based on the P50 in the developer's forecast during the first four years of operation.[151] Once the facility has been in service for four years, PacifiCorp forecasts generation based on the facility's actual capacity factor.

Staff argues that PacifiCorp is not using the "best information available" to forecast QF generation[152] even though the Company uses the same methodology Staff has advocated for PacifiCorp-owned facilities.[153] Staff claims that because QFs have historically under-generated relative to their forecasts, the Commission should impute lower QF generation. Because QF generation was [redacted] less than forecast in 2020, Staff recommends an adjustment to reduce

[148] PAC/1100, Wilding/10 (quoting Docket No. UM 1050, PAC/101, App'x D at 3 (Dec. 3, 2019)).
[149] PAC/1100, Wilding/9.
[150] PAC/1100, Wilding/9.
[151] PAC/1000, Staples/51-52.
[152] Staff/1100, Zarate/3.
[153] PAC/1000, Staples/52.

the 2022 forecasted QF generation by [redacted], which equates to a $1.53 million adjustment to NPC for 2022.[154] The Commission should reject Staff's recommendation.

First, Staff's position is contradictory. Staff has argued *for* using P50 forecasts for PacifiCorp-owned resources in order to *decrease* NPC and while arguing *against* using P50 forecasts for QFs in order to *decrease* NPC. Staff failed to articulate any principled basis to use different forecasting methodologies for QFs. If the use of P50 forecasts represents the best information available to PacifiCorp regarding its owned resources, then that same information should be used for QF generation.

Second, Staff provides no reasonable basis to apply its historical true-up to only QF generation, particularly in the context of PacifiCorp's long-standing under-recovery of NPC.[155] For QFs, Staff looked at the historical forecast generation, compared it to the actual generation, calculated the [redacted] over-forecast for 2020, and then adjusted the forward-looking 2022 forecast down by [redacted] to make up for the historical under-forecast.[156] Staff's use of what amounts to a historical true-up, however, was applied to only one element of the overall NPC. Had Staff calculated the difference between forecasted and actual costs for all NPC elements (not just QFs) and then applied that percentage difference to the 2022 forecast, it would have resulted in an 8 percent *increase* to the 2022 TAM because the Company's 2020 NPC forecast was 8 percent less than actuals.[157]

When asked whether Staff even considered the historical under-forecasting of NPC when proposing adjustments, Staff responded that "Staff does not explicitly consider PacifiCorp's specific over- or under-recovery of NPC from prior years when making principled recommendations to improve the accuracy and reasonableness so [sic] of the TAM forecast, which is forward-looking."[158] Staff cannot have it both ways. If it is appropriate to single-out QF

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[154] Staff/1100, Zarate/3.
[155] *See* PAC/400, Staples/14, Figure 2.
[156] Staff/500, Zarate/12-14.
[157] *See* PAC/400, Staples/14 (2020 NPC collected through rates was $307.4 million, while actual NPC was $335.6 million).
[158] PAC/1600 at 12 (Staff Response to PAC 8(b)).

generation for a historical true-up, then it is appropriate to apply the same treatment to every NPC element or at least consider the impact of applying the same adjustment across the board. The fact that Staff views historical over-recovery of only certain costs when making adjustments, without regard for overall context or costs that have been historically under-forecast, undermines the rationale for its adjustment.

Finally, Staff supported its QF adjustment by claiming that a "[redacted] [historical] overstatement of costs is still significant for purposes of setting TAM rates."[159] The Company's 2020 under-recovery of NPC was [redacted] that amount, which presumably also makes it "significant for purposes of setting TAM rates."

E. The Company's new CSAs are prudent and include reasonable minimum take provisions.

The 2022 TAM includes five new CSAs—two for the Hunter plant, two for the Dave Johnston plant, and one for the Craig plant. When evaluating a contract like a CSA, the Commission examines whether the utility's decision was reasonable "in light of the circumstances existing at the time [the utility] entered into the contract[]."[160] The prudence standard is objective and "review[s] the reasonableness of the [utility's] actions based on information that was available or could reasonably have been available at the time of the action."[161] Because of the "need for regulatory certainty," the Commission "must exercise a high degree of caution" in assessing prudence.[162] Prudence "does not require optimal results,"[163] and the Commission has "acknowledge[d] the possibility that a prudently-made decision might turn out to be the wrong decision."[164]

[159] Staff/1100, Zarate/2.
[160] *In re Portland Gen. Elec. Co., Application for Annual Adjustment to Schedule 125 under the terms of the Res. Valuation Mechanism*, Docket No. UE 139, Order No. 02-772 at 11 (Oct. 30, 2002).
[161] Order No. 02-772 at 11.
[162] Order No. 02-772 at 11.
[163] Order No. 12-493 at 25.
[164] Order No. 02-772 at 11.

Here, the record demonstrates that the Company's decision to execute each of the five new CSAs was objectively reasonable and consistent with standard industry practices. The minimum take levels are reasonable, conservative, and supported by robust economic analysis.

1. PacifiCorp's coal procurement strategy is consistent with industry standards and mitigates risks associated with changing market and regulatory conditions.

Unlike other fuels, such as natural gas, there is no central, liquid market for coal.[165] Coal quality specifications vary by region, transportation costs are significant, and many of PacifiCorp's coal plants are located with few nearby coal suppliers.[166] Indeed, except for the Dave Johnston plant, none of PacifiCorp's plants are served by a liquid coal market, which means that the Company must enter into CSAs to fuel its plants.[167]

The primary purpose of a CSA is to support the reliability of the Company's power supply by ensuring that there is sufficient fuel to operate a coal-fired power plant when needed to serve customers.[168] Given the need for a reliable fuel supply, PacifiCorp's goal is to secure the least-cost, least-risk fuel supply for customers. The Company begins with an estimate of annual future generation forecast of the plants, which consider many factors including historical usage patterns, sales and load forecasts, market prices, changes in available generation, operating lives, and reliability requirements.[169] The Company then develops fuel volume, pricing and sourcing assumptions, transportation costs, and if necessary, operating and capital costs for the plant.[170] The generation forecast used to inform CSA negotiations covers the entire life of the potential agreement and includes resource build-out assumptions consistent with the most recently acknowledged integrated resource plan (IRP).[171] Where a dedicated, jointly-owned mine supplies

[165] PAC/600, Ralston/10.
[166] PAC/600, Ralston/10.
[167] PAC/600, Ralston/18.
[168] PAC/500, Schwartz/6.
[169] PAC/600, Ralston/9.
[170] PAC/600, Ralston/9.
[171] PAC/600, Ralston/22.

a plant, PacifiCorp collaborates with other owners to develop a mine plan to provide a stable and reliable fuel supply.[172]

When negotiating a CSA, the Company considers and evaluates factors like term, price, volume, supplier creditworthiness, plant location/coal region, coal supply options, coal transportation options, and coal quality.[173] The Company seeks to strike the optimum balance among these sometimes-competing factors to ensure that the CSA is reasonable and will provide a least-cost, least-risk fuel supply when examined in its entirety.

Given current and expected market conditions, the Company limits the term of its coal supply agreements as much as practicable to minimize risk and add flexibility to its system planning.[174] This typically means that the Company will not execute a CSA with a term greater than five years.[175] This strategy allows the Company to continually reassess its least-cost, least-risk resource portfolio in its IRP.[176] PacifiCorp has also included environmental response or change of law provisions where possible in its contracts with longer terms.

Virtually "all coal supply contracts have a minimum volume commitment to purchase coal."[177] These provisions typically require PacifiCorp to purchase a minimum amount of coal each year under the CSA or pay the difference between the amount delivered and the minimum take requirement.[178] Because PacifiCorp must purchase coal via contracts, PacifiCorp must commit to purchasing a minimum volume.[179] Minimum-take requirements are not only unavoidable in a CSA but they also significantly reduce the risk associated with fuel availability.[180] Multi-year contracts also significantly reduce the risk to customers associated with market price volatility, much like a traditional hedging transaction.[181] There would be substantially higher risk

[172] PAC/600, Ralston/9-10.
[173] PAC/600, Ralston/10.
[174] PAC/600, Ralston/10.
[175] PAC/200, Ralston/3.
[176] PAC/600, Ralston/12.
[177] PAC/500, Schwartz/14.
[178] *See* PAC/200, Ralston/6 (explaining the need for minimum takes).
[179] PAC/500, Schwartz/14.
[180] PAC/600, Ralston/11.
[181] PAC/600, Ralston/11.

if the Company did not have fuel for electricity generation during certain times of the year.[182] Minimum take provisions are especially important for most of PacifiCorp's coal fleet because of the inability to receive significant quantities of coal from other sources.[183]

In the 2017 TAM, the Commission found that the Company's CSAs including minimum take provisions were prudent because minimum take requirements are "typical in coal supply agreements and that, without entering into supply agreements with these types of provisions, [PacifiCorp] would have to rely on the spot market with the attendant supply and price risk."[184]

Here, each of the new CSAs has a reasonable minimum take level based on the Company's comprehensive forecasting of expected generation levels during the term of the CSA.

a) The Hunter CSAs are prudent.

The Company executed two new CSAs for the Hunter plant, which together provide the plant's total fuel requirements.[185] The CSAs have a [redacted] term, which began in 2021.[186] The combined minimum take requirement for both CSAs is [redacted] tons per year, which is a conservative figure given the expected generation at the plant.[187] PacifiCorp's generation forecast used to inform the Hunter CSA negotiations included the full resource build-out from the 2019 IRP's preferred portfolio and allowed Hunter to economically cycle using the same methodology that the Commission has approved for setting rates in the TAM.[188] Staff testified that the Company's forecast was "robust and appropriate."[189] The Company's forecast showed an "expected" annual burn for Hunter from [redacted].[190] Under the Company's "high" burn forecast, Hunter's annual burn over the same period was [redacted] and under the Company's "low" burn forecast, Hunter's annual burn was [redacted].[191] For

[182] PAC/600, Ralston/11.
[183] PAC/600, Ralston/11.
[184] 2017 TAM, Order No. 16-482 at 9.
[185] PAC/200, Ralston/7.
[186] PAC/200, Ralston/7.
[187] PAC/200, Ralston/8.
[188] PAC/700, MacNeil/2-4.
[189] Staff/700, Anderson/18.
[190] PAC/500, Schwartz/35.
[191] PAC/500, Schwartz/35-36.

the Company to be over-contracted for coal, the coal burn at Hunter would have to be at least [redacted] below the "low" burn forecast and [redacted] below the "expected" burn forecast *for* [redacted].[192]

Although PacifiCorp's analysis used to inform the CSA negotiations allowed Hunter to cycle, economic cycling did not materially impact the forecasted generation. For example, if the Company economically cycled Hunter for 10 weeks rather than operating at its minimum operating level, it would have reduced the coal burn by only [redacted].[193] Given that the burns in the *"low" burn* scenario are [redacted] than the minimum take, even a reduction of [redacted] to the "expected" burn would not have materially changed the negotiated minimum take level.

In 2021, PacifiCorp nominated [redacted] tons, consistent with the "expected" annual burn and [redacted] than the minimum take level.[194] In 2022, the TAM forecasts a burn of [redacted] tons, meaning that forecasted burns are [redacted] than the minimum take.[195]

Staff's testimony acknowledged that the pricing in the new CSAs made the costs for Hunter [redacted] than the system average cost for coal resources and [redacted] than the average system costs for all resources in 2022.

b) The Dave Johnston CSAs are prudent.

PacifiCorp executed two new CSAs for the Dave Johnston plant, both of which have [redacted] terms beginning in 2021.[196] Unlike the Hunter CSAs, however, the new Dave Johnston CSAs are not full requirements; instead, the new CSAs represent only [redacted] of the generation expected for 2022.[197] Indeed, the plant has an open position for 2022; only [redacted] of the expected coal consumption is currently under contract.[198] This open position provides significant flexibility around the minimum take obligation in the new CSAs.[199] Moreover, one of the new

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[192] PAC/500, Schwartz/36.
[193] PAC/700, MacNeil/8 (. . . operating Hunter Unit 3 at its minimum operating level for a week represents just 0.3 percent of the contracted coal minimum take.").
[194] PAC/500, Schwartz/35-36.
[195] *See* PAC/600, Ralston/25.
[196] PAC/200, Ralston/3.
[197] PAC/1200, Ralston/9-10.
[198] PAC/500, Ralston/15.
[199] PAC/1200, Ralston/10.

CSAs allows PacifiCorp to defer up to [redacted], which provides additional flexibility if generation is significantly less than expected.[200] Like Hunter, PacifiCorp's analysis covered the full term of the new CSAs, included the 2019 IRP resource buildout, and allowed Dave Johnston to economically cycle using the same methodology that the Commission had approved for setting rates in the TAM.[201]

Staff acknowledged that with the new CSAs, Dave Johnston is the [redacted] cost coal resource and is [redacted] cost than the system average coal resource and [redacted] cost than the average cost for all resources.[202]

c) The Craig CSA is prudent.

PacifiCorp executed a new full requirement CSA for the Craig plant with the Trapper Mine, which is co-owned by PacifiCorp and other owners of the plant. The term of the new CSA is five years, beginning in 2021.[203] Because PacifiCorp co-owns the mine, the Craig CSA has flexibility that allows PacifiCorp to adjust its minimum take obligation annually based on agreement of the mine owners.[204] Like Hunter and Dave Johnston, PacifiCorp's forecast for the Craig CSA covered the full contract terms and included the 2019 IRP resource buildout.[205] The Company did not allow Craig to economically cycle, however, because the Company cannot unilaterally choose to cycle the plant given its minority ownership share.[206] This is consistent with the economic cycling methodology the Commission approved for ratemaking in the 2017 TAM.[207] If the Company had allowed the plant to economically cycle, it would have reduced the plant's generation by a mere [redacted], which would not have materially impacted the minimum take level PacifiCorp agreed to in the new CSA particularly given the flexibility in the agreement.[208]

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[200] PAC/200, Ralston/5.
[201] PAC/1000, Staples/12; PAC/600, Ralston/15.
[202] Staff/600, Fox/14 (Confidential Staff Table 4).
[203] PAC/200, Ralston/9.
[204] PAC/1200, Ralston/10.
[205] PAC/600, Ralston/15.
[206] PAC/600, Ralston/15.
[207] 2017 TAM, Order No. 16-482 at 10-11.
[208] PAC/1000, Staples/13.

Like Hunter and Dave Johnston, Staff acknowledged that with the new CSA, the Craig plant is [redacted] cost than the system average cost for coal resources and the average cost for all resources.[209]

2. The Commission should reject Staff's recommendation to deem the new CSAs imprudent.

Staff recommends that the Commission find that the five new CSAs are imprudent because the minimum take levels are excessive.[210] Staff's only basis for this recommendation is the contention that the Company did not adequately consider opportunities to economically cycle its coal plants.[211] Staff argues that the Company must perform a "full assessment" of economic cycling at *all* its coal units before executing any new CSAs and that modeling economic cycling at only the units subject to the new CSA is inadequate.[212] Staff speculates that if PacifiCorp had considered economic cycling in this manner, it would have reduced the forecasted generation levels at Hunter, Dave Johnston, and Craig such that the minimum take level in the new CSAs would have been materially lower.[213] As a remedy, Staff recommends that the Company model the new CSAs without a minimum take obligation for the entire CSA term, including in future TAMs.[214]

The Commission should reject Staff's recommendation because (1) Staff's novel prudence standard is contrary to Commission precedent; (2) Staff improperly applies its novel prudence standard retroactively; (3) the record shows there are limited opportunities to economically cycle coal plants and allowing economic cycling does not materially change the minimum take levels in the new CSAs; and (4) Staff provides no evidence that the minimum take levels are unreasonable.

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[209] Staff/600, Fox/14.
[210] Staff/1400, Anderson/10-11.
[211] Staff/1400, Anderson/10-11.
[212] Staff/1400, Anderson/10.
[213] *See* Staff/1400, Anderson/10-11.
[214] Staff/1400, Anderson/10-11.

a) Staff's novel prudence standard includes modeling that the Commission has never required when setting NPC or as a prerequisite to executing a CSA.

The Commission has never required PacifiCorp to perform a full assessment of economic cycling as a prerequisite to executing a CSA. Staff admits it has never applied this standard before and appears to concede that it is a departure from the Commission's long-standing prudence standard.[215] Indeed, Staff admits it was unaware of its novel prudence requirement until it filed rebuttal testimony and proposed it for the first time.[216] Staff's *ex post facto* position that the Company should model economic cycling before executing new CSAs is contrary to the Commission prudence standard, which looks at the "*objective reasonableness* of a decision at the time it was made[.]"[217] The fact that Staff could not even formulate its prudence standard until its rebuttal testimony undermines its claim that an objectively reasonable utility would have undertaken Staff's recommended modeling before executing a CSA. Staff's position amounts to a hindsight review and retroactive application of a new standard in violation of Commission precedent.[218]

Moreover, Staff's recommendation cannot be squared with the modeling the Commission has approved in recent TAMs. PacifiCorp has modeled economic cycling in the last four TAMs under settlement agreements approved by the Commission.[219] Most recently, in the 2021 TAM, Staff recommended (1) that the Company remove the must run setting from GRID and allow economic cycling in the TAM and (2) that the Company perform an economic cycling study.[220] The Company agreed to both requests as part of a settlement, which the Commission subsequently

[215] PAC/1600 at 6 (Staff Response to PacifiCorp Data Request 4(b)).
[216] PAC/1600 at 6 (Staff Response to PacifiCorp Data Request 4(a)).
[217] 2017 TAM, Order No. 16-482 at 6 (emphasis added).
[218] *See, e.g.*, Order No. 20-473 at 35 ("[The Commission] must determine whether the company's actions and decisions, *based on what it knew or should have known at the time*, were prudent in light of existing circumstances.") (emphasis added).
[219] *See, e.g.*, *In re PacifiCorp, dba Pac. Power, 2019 Transition Adjustment Mechanism*, Docket No. UE 339, Order No. 18-421, App'x A at 6 (Oct. 26, 2018) [hereinafter 2019 TAM]; *In re PacifiCorp, dba Pac. Power 2021 Transition Adjustment Mechanism*, Docket No. UE 375, Order No. 20-392, App'x A at 8 (Oct. 30, 2020) [hereinafter 2021 TAM]; PAC/100, Webb/14.
[220] 2021 TAM, Order No. 20-392 at 4.

approved.[221] In the 2021 TAM, Staff never asserted that removing the must run setting or performance of a cycling study was a prerequisite to executing a CSA. Indeed, Staff never tied its cycling recommendations to the prudence of new CSAs at all, even the CSAs that were subject to a prudence review in the 2021 TAM.[222] Then, in this case, PacifiCorp provided the Economic Cycling Study—as Staff requested—and removed the must run setting—as Staff requested—and Staff responded by claiming that the new CSAs are per se imprudent because PacifiCorp did not perform a "full assessment" of economic cycling that Staff had never before proposed or requested.

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. PacifiCorp's reliance on the same modeling used to set customer rates is objectively reasonable and prudent.

b) PacifiCorp reasonably considered economic cycling before executing the new CSAs.

PacifiCorp disagrees that a CSA is per se imprudent if the Company did not conduct a full assessment of economic cycling before executing the CSA. But even if Staff's novel standard is applied to the Hunter, Dave Johnston, and Craig CSAs, the evidence in the record demonstrates that PacifiCorp has performed substantively the same analysis Staff recommends. Staff has explained that its recommended "full assessment" of economic cycling should be designed to identify units "that could provide *significant benefits* through economic cycling."[223] According to Staff, "[f]or units that show potential to benefit ratepayers through economic cycling, [CSAs] should seek to obtain a minimum take level that would facilitate economic cycling[.]"[224] Staff largely ignores or dismisses the extensive record in this case, which shows that economic cycling provides minimal customer benefits and specifically that cycling Hunter, Dave Johnston, and Craig is unlikely to provide any benefits or materially reduce the expected generation at those plants

[221] 2021 TAM Order No. 20-392 at 10, App'x A at 6, 8.
[222] *See* PAC/1000, Staples/5.
[223] PAC/1600 at 4 (Staff Response to PacifiCorp Data Request 3) (emphasis added).
[224] Staff/1400, Anderson/4.

during the terms of the new CSAs. Therefore, applying Staff's own standard provides no basis to impute a different minimum take obligation in the new CSAs.

_c)_ Economic cycling will not materially decrease the minimum take levels because there are limited opportunities for economic cycling in actual operations.

Economic cycling rarely occurs in actual operations,[225] which is why the Commission previously rejected recommendations to model economic cycling in the 2018 TAM.[226] Since the 2018 TAM, the Company has not economically cycled coal plants at any significant level because of higher natural gas prices, lower hydro generation, and lower minimum operating levels at coal-fired facilities.[227] Shutting down units, rather than running at the minimum operating level, also incurs start-up costs and creates reliability risk because of slow start-up times.[228] The continued addition of renewable resources into the Company's generation fleet also requires the presence of significant online dispatchable resource capacity to integrate and reliably serve load with those new resources.[229]

Despite the limited cycling that occurs in actual operations, the Company has modeled economic cycling in the past four TAMs, including the removal of the must run setting in the 2022 TAM.[230] Because of GRID's perfect foresight and ability to perfectly optimize PacifiCorp's system, GRID models more economic cycling than can occur in actual operations.[231] For example, in the 2019 TAM, GRID forecast [redacted] hours of offline time and approximately [redacted] avoided MWh.[232] But in actual operations, PacifiCorp only [redacted].[233] By removing the must run settings in the 2021 TAM (which maintained certain limitations), GRID forecasted [redacted] of cycled hours through July.[234]

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[225] PAC/1000, Staples/7.
[226] *In re PacifiCorp, dba Pac. Power 2018 Transition Adjustment Mechanism*, Docket No. UE 323, Order No. 17-444 at 11 (Nov. 1, 2017) [hereinafter 2018 TAM].
[227] PAC/1000, Staples/7.
[228] PAC/100, Webb/13.
[229] PAC/1000, Staples/8.
[230] PAC/100, Webb/14.
[231] PAC/100, Webb/16.
[232] PAC/1000, Staples/9.
[233] PAC/1000, Staples/9.
[234] PAC/1000, Staples/7.

In actuality, through July 2021, when coal plants have been historically allowed to conduct economic cycling, the Company had only [redacted] cycled hours or [redacted] percent of the GRID forecast.[235]

d) The Company's studies confirm that economic cycling provides insignificant cost savings.

PacifiCorp's Economic Cycling Study and the 2022 TAM without must run settings confirm that economic cycling generally produces minimal customer savings and none of the plants with new CSAs are expected to provide significant benefits through economic cycling.

The Economic Cycling Study, which is based on 2021 TAM inputs, removed the must run setting altogether, which Staff concedes allowed the "units to cycle off whenever GRID expects that their operation would be uneconomic."[236] Without restraints of any kind, and without considering reliability at all, the Economic Cycling Study resulted in a modest [redacted] reduction in coal generation.[237] More importantly, however, the study showed that when coal units are allowed to cycle without restraint, economic cycling provided [redacted].[238]

The 2022 TAM GRID study also removed all the must run settings, although the Company included several additional modeling constraints to produce results that "were rational and consistent with prudent utility practice and feasible operations."[239] The 2022 TAM study showed that economic cycling reduced coal generation by only [redacted] and had a *de minimis* impact on NPC relative to a GRID study with must run settings enabled.[240]

Importantly, both studies likely overstated the amount of economic cycling relative to actual operations because of GRID's perfect foresight and because neither study fully accounted for reliability issues. Imposing additional reliability constraints on economic cycling would have

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[235] PAC/1000, Staples/7.
[236] Staff/700, Anderson/2.
[237] PAC/107, Webb/2.
[238] PAC/107, Webb/1.
[239] PAC/100, Webb/14.
[240] PAC/107, Webb/2. The Company acknowledges that the 2022 TAM study was not necessarily based on information that was available at the time that the Company executed the new CSAs, which is what the prudence standard examines. However, Staff's recommendation in this case states that if the Company can demonstrate through a subsequent cycling study that the minimum take levels in the new CSAs are reasonable, then the Commission should no longer ignore the minimum take levels in the TAM. Staff/700, Anderson/18. Therefore, Staff's recommendation has made the 2022 TAM study relevant.

decreased cycling in the studies. Thus, while each study was imperfect, the imperfections tended to overstate economic cycling. Staff's claims that if the Company had considered economic cycling, the forecasted generation at Hunter, Dave Johnston, and Craig would have been materially lower such that the minimum take level could have been reduced. But these two studies show the opposite—cycling produces modest overall reductions in coal generation and produces virtually no NPC savings, which undercuts the entire rationale for Staff's recommendation.

e) **Allowing economic cycling at Hunter, Dave Johnston, and Craig would not materially impact the minimum take levels at those plants.**

The Company's analysis used to inform the Hunter and Dave Johnston CSAs specifically allowed economic cycling and, if the Craig study had allowed cycling, it would not have materially affected the minimum take level in the new CSA.[241] Staff did not dispute any of this analysis. Instead, Staff criticizes these analyses because they did not allow other coal units to economically cycle, which Staff believes would have produced a materially lower generation forecast at each of the plants.[242] Staff's position is illogical. If additional coal units are allowed to cycle, then it *decreases* the likelihood that the unit being studied will cycle because that unit is competing with other, potentially higher cost alternatives.[243] In other words, a study that allowed only individual units or plants to cycle will generally produce a lower generation forecast (i.e., the study will allow more cycling) than a study that allows all units to cycle. This means that the Company's forecasts of Hunter, Dave Johnston, and Craig likely produced a lower generation forecast than would have occurred if the Company had implemented Staff's recommendation and allowed all units to cycle in the same study.

The Economic Cycling Study and the 2022 TAM study bear out the Company's position. In the Economic Cycling Study, where all units are allowed to cycle, the generation at Hunter and Dave Johnston [redacted].[244] In the 2022 TAM study, where all units were allowed to cycle, the

[241] *See* PAC/1000, Staples/12-13.
[242] Staff/1400, Anderson/10.
[243] PAC/1000, Staples/15.
[244] PAC/107, Webb/3-4.

generation at Hunter, Dave Johnston, and Craig also [redacted].[245] These consistent results are entirely logical because, as Staff testified, lower cost units are less likely to economically cycle as compared to higher cost units and Hunter, Dave Johnston, and Craig are [redacted] cost units.[246] Thus, when higher cost units economically cycle, the lost generation is made up elsewhere, including at lower cost coal units, like Hunter, Dave Johnston, and Craig.

Again, Staff claims that before the Company executes new CSAs it must seek to identify units that could potentially provide *significant benefits* by economically cycling.[247] The evidence in the record, when viewed in its entirety, demonstrates that Hunter, Dave Johnston, and Craig are not plants that are expected to provide significant savings, or any savings at all, due to economic cycling. If anything, the evidence shows that the analysis Staff recommends will likely result in a [redacted] generation forecast for each of these plants, which would potentially increase the minimum take level in the new CSAs. Therefore, Staff's claim that the new CSAs are imprudent for failing to consider economic cycling has no evidentiary support.

f) Staff provided no evidence that the CSAs have excessive minimum take levels.

While the Company has the burden of proof to show that its CSAs are prudent, Staff has the "burden of producing evidence" to support their argument in opposition of PacifiCorp's position.[248] Here, Staff has not produced *any evidence* that the minimum take levels included in the new CSAs are excessive.

Staff admitted that it has not "performed any quantitative analysis showing that if the Company had considered economic cycling in the manner that Staff recommends, the level of generation at Hunter, Craig, or Dave Johnston would have been materially lower than the level of

[245] PAC/1601 at 1-2.
[246] Confidential Evid. Tr. 2:24-3:4; Staff/600, Fox/14.
[247] *See* PAC/1600 at 1-2 (Staff Response to PacifiCorp Data Request 1).
[248] *See, e.g.*, Order No. 20-473 at 5 (discussing the burden of proof requirements); *In re Portland Gen. Elec. Co., 2012 Annual Power Cost Update Tariff (Schedule 125)*, Docket No. UE 228, Order No. 11-432 at 3 (Nov. 2, 2011) ("Once a utility has met the initial burden of presenting evidence to support its request, 'the burden of going forward then shifts to the party or parties who oppose including the costs in the utility's revenue requirement.'") (quoting *In re Nw. Nat. Gas Co., Request for a Gen. Rate Revision*, Docket No. UG 132, Order No. 99-697 at 3 (Nov. 12, 1999)).

generation relied on by the Company when negotiating the coal supply agreements."[249] To the contrary, the analysis Staff has performed supports the prudence of the CSAs. Staff agrees that Dave Johnson "is unlikely to be elected for economic cycling because of its relatively low cost."[250] For Craig, Staff directly acknowledged that the minimum take levels in the new CSA "[redacted]."[251] By admitting that generation is unlikely to fall below the minimum take levels, Staff implicitly concedes that the decision to enter the CSA was prudent based on objective reasonableness.

Staff provided no evidence in this case that economically cycling coal units will produce material customer savings. More importantly, Staff has not disputed that the Economic Cycling Study shows that when every single unit was allowed to cycle without restraints of any kind, there were [redacted].[252] Staff also did not dispute that when the must run setting was removed from GRID in the 2022 TAM, NPC actually [redacted] as a result of allowing economic cycling.[253]

At hearing, Staff was dismissive of both the Economic Cycling Study and the removal of the must run setting from the 2022 TAM because neither study appropriately accounted for system reliability.[254] But if either study had fully accounted for reliability, there would have been less economic cycling because PacifiCorp cannot increase reliability by taking more units offline. This means the Economic Cycling Study and 2022 TAM show the maximum possible cycling that can be achieved based exclusively on economics and without regard for reliability and both studies—which resulted directly from Staff's own recommendations in the 2021 TAM—show that economic cycling provides [redacted]. Staff's recommendation assumes significant NPC savings as a result of economic cycling even though there is no evidence supporting this

[249] PAC/1600 at 6 (Staff Response to PacifiCorp Data Request 4(c)).
[250] Staff/1400, Anderson/11.
[251] Staff/1400, Anderson/10; PAC/1000, Staples/12 n. 29 (designating Staff's testimony confidential).
[252] Confidential Evid. Tr. 4:20-5:4.
[253] Confidential Evid. Tr. 7:22-8:9; *see also* Staff/600, Fox/7-8.
[254] Confidential Evid. Tr. 4:20-5:10.

assumption and two studies directly contradicting Staff's assumption. Therefore, the record contains no evidence supporting Staff's recommendation that the CSAs are imprudent.

_g)_ Staff's recommended remedy has no evidentiary support.

As a remedy for its claimed imprudence, Staff recommends entirely removing the minimum take level from the new CSAs for purposes of modeling in the TAM.[255] But there is no evidence that the Company could enter into a CSA without a minimum take.[256] Staff admits it performed no analysis to impute a reasonable minimum take level assuming that the Company had performed the studies Staff recommends.[257] Therefore, even if the Commission were to conclude that the new CSAs are imprudent, the remedy is not to eliminate the minimum take level, it is to impute a reasonable one. And the evidence in the record shows that the type of analysis Staff recommends would have [redacted] generation at Hunter, Dave Johnston, and Craig and therefore the Commission should, if anything, impute a [redacted] minimum take level.[258] Eliminating the minimum take is therefore the exact opposite remedy for the allegedly imprudent CSAs.

Moreover, Staff's recommendation improperly views the minimum take provision in the CSAs in isolation and without regard for the overall terms and conditions. Generally, the minimum take level and price are inversely proportional, i.e., a higher minimum take level typically produces a lower price.[259] Staff cannot eliminate the minimum take level without also accounting for the impact that would have on CSA pricing.

3. A CSA is not imprudent simply because PacifiCorp must iteratively model plant dispatch in GRID to move fuel consumption onto the supply curve.

PacifiCorp uses an iterative process because GRID cannot accept multiple pricing tiers.[260] So when a CSA has multiple pricing tiers, PacifiCorp must use as the initial input to GRID the

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[255] Staff/1400, Anderson/10.
[256] *See* PAC/500, Schwartz/30 (testifying that having less than 50 percent of coal for a year under contract would be "highly risky").
[257] PAC/1600 at 7 (Staff Response to PacifiCorp Data Request 5).
[258] *See* PAC/1000, Staples/15; Staff/600, Fox/14; Confidential Evid. Tr. 2:24-3:4.
[259] PAC/500, Schwartz/15-16.
[260] PAC/400, Staples/51.

best incremental price.[261] But if the results are substantially off the supply curve (i.e., the volume consumed does not match the price for the volume consumed), then PacifiCorp must adjust the incremental price to move it back onto the CSA's supply curve to minimize costs.[262] The iterative process can require an increase to incremental price (e.g., if GRID is consuming sufficient volumes to move into a higher-priced tier, then the incremental price must be increased) or a decrease to the incremental price (e.g., if GRID is not consuming the minimum take level in a CSA).[263] When the iterative process requires a lower incremental price in order to ensure that the plant meets its minimum take, that solution is least-cost for customers because the minimum take obligation is a sunk cost that cannot be avoided (as discussed in more detail below).[264] As PacifiCorp explained at hearing, the decision is whether to burn the coal that has already been paid for and produce a benefit for customers to offset the sunk cost, or forego burning the coal and replacing that generation with some other source while still paying for the coal that was not burned.[265] If the net value of a generation resource is greater than zero it will always be least-cost to use coal up to the minimum take requirement. Therefore, when PacifiCorp utilizes the iterative process to adjust a coal plant's incremental cost to increase dispatch, it maximizes customer benefits and minimizes NPC.[266] The Commission previously approved the Company's modeling for this reason.[267]

Moreover, the fact that PacifiCorp decreases the dispatch price in order to meet the minimum take requirement does not, in itself, indicate that the minimum take level is too high or that the CSA is producing uneconomic dispatch. PacifiCorp's expert witness explained that, "PacifiCorp should, and does, minimize its cost of coal for power generation," but the "first priority is reliability of power supply and that means reliability of fuel supply."[268] Therefore, "there may be times when PacifiCorp incurs costs to commit for coal to have the capability to meet full load

[261] Confidential Evid. Tr. 23:2-21.
[262] Confidential Evid. Tr. 23:2-21.
[263] Confidential Evid. Tr. 23:2-21.
[264] Confidential Evid. Tr. 23:22-24:9.
[265] Confidential Evid. Tr. 23:22-24:9.
[266] Confidential Evid. Tr. 23:22-24:9.
[267] 2017 TAM, Order No. 16-482 at 11.
[268] PAC/500, Schwartz/10-11.

that it does not need to burn during the year based on actual demand and the economics of other power supplies."[269] In other words, the minimum take level is set not only to achieve a reasonable price, but first and foremost to ensure reliable fuel supplies.

Finally, because minimum take levels are inversely proportional to price, a lower minimum take will likely require a higher price.[270] So it is not imprudent or uneconomic if PacifiCorp burns coal to meet a minimum take obligation that would potentially not be burned if there were no minimum take, because customers received value for all of the coal that was consumed at a lower price than would have been otherwise available with a different minimum take level.

4. PacifiCorp's focus on lower minimum burns and increased renewable generation allows for lower coal generation without widespread economic cycling.

Unlike economic cycling, which produces limited benefits and can cause significant reliability concerns, the Company has focused on reducing coal generation by lowering minimum stable run levels and increasing renewable generation.[271] Indeed, since 2016, PacifiCorp has reduced the minimum operating levels by 43 percent.[272] This effect has been evident in this proceeding, where the Company's initial filing projected a $114 million reduction in coal costs compared to the 2021 TAM.[273] Of this amount, only $[redacted] can be attributed to economic cycling.[274]

F. CUB's and Staff's proposal to conduct a stand-alone Jim Bridger economic cycling study would not provide additional insight for the Company's 2022 NPC forecasts.

Outside of Staff's position on the use of economic cycling in CSAs, CUB and Staff also recommend that PacifiCorp conduct a stand-alone economic cycling study in GRID to determine any potential benefits from cycling Jim Bridger Unit 1 for the entirety of quarter two.[275] Under the 2021 TAM settlement, CUB or Staff can request a model run with these assumptions in Aurora

[269] PAC/500, Schwartz/10-11.
[270] PAC/500, Schwartz/15-16.
[271] PAC/1000, Staples/8.
[272] PAC/400, Staples/60, Figure 5.
[273] PAC/1000, Staples/8.
[274] PAC/1000, Staples/8.
[275] CUB/100, Jenks/16-17; Staff/1400, Anderson/17-18.

for the 2023 TAM.[276] Any study in this case, however, will be too late to provide insight into the Company's NPC forecasts in 2022. Even if PacifiCorp did conduct such a study, the results would likely not change Jim Bridger's status during [redacted].[277]

CUB also suggests that PacifiCorp should "generally allow" Jim Bridger Unit 1 to cycle in GRID and actual operations.[278] To the extent that CUB's request to conduct economic cycling studies for Jim Bridger would affect actual operations, such a study is outside the scope of the TAM, which solely focuses on forecasted NPC.[279] CUB argues that the IRP "raised questions" about the continued viability of Jim Bridger Unit 1 in 2022 and 2023,[280] but these discussions are also outside the scope of this proceeding. Any long-term economic benefit the stochastic IRP model found in cycling or shutting down Jim Bridger Unit 1 does not affect how GRID models the operation of Jim Bridger Unit 1 in the 2022 TAM.[281]

G. Staff's proposal to require a GRID run without liquidated damages or take or pay costs eliminates the usefulness of this modeling run.

As part of the 2021 TAM settlement, PacifiCorp agreed to perform an "Informational Run" based on the initial TAM filing that uses an average coal price for dispatching coal plants and "removes any operational constraints related to the minimum take provisions in the coal supply agreements."[282] The Company provided this Informational Run in its initial filing.[283] While the Informational Run dispatched plants without regard for minimum take provisions, PacifiCorp adjusted the results from the model run to account for the costs of failing to meet these

[276] *See* 2021 TAM, Order No. 20-392, App'x A at 6 ("PacifiCorp . . . agree[s] to conduct one AURORA model run per intervenor, so long as the request is reasonable and PacifiCorp has a reasonable time to complete the request during future NPC forecast mechanism proceedings.").
[277] PAC/400, Staples/40.
[278] CUB/100, Jenks/17-18.
[279] Order No. 09-274, App'x A at 9 (stipulating that the TAM "is an annual filing with the objective to update the forecast net power costs to account for changes in market conditions[.]").
[280] CUB/200, Jenks/14.
[281] PAC/1000, Staples/17.
[282] 2021 TAM, Order No. 20-392, App'x A at 6.
[283] PAC/100, Webb/24.

provisions.[284] Staff disagreed with this approach and proposed a new definition for the Informational Run that would exclude all costs related to minimum take provisions.[285]

PacifiCorp objects to Staff's proposal because it would undermine the accuracy and usefulness of the Informational Run. The Commission has previously acknowledged the need to model minimum take provisions "to achieve the overall least-cost dispatch of the entire coal fleet while meeting the minimum-take obligations for each plant."[286] An Informational Run that does not account for costs the Company will incur cannot provide insight into cost savings. To establish a tangible benefit, any savings found in the Informational Run must be compared against the cost incurred while generating those potential savings. Arbitrarily removing costs that would be incurred if this course of action were pursued in actual operations exaggerates any potential savings and misleads rather than illuminates.[287]

H. The Company has prudently managed the Huntington CSA and will continue to do so.

In general, PacifiCorp agrees with CUB's recommendation that the Company should "prudently manage" the termination clause in its Huntington CSA[288] and that the risks of contract termination can outweigh any value associated with termination.[289] The Company will continue to monitor market and regulatory conditions to assess whether there is an opportunity to invoke the termination clause. But to be clear, the Company's analysis at this time does not support termination.

As CUB recognizes, triggering a termination clause could put PacifiCorp in breach of its CSA unless the Company can be confident that economic and regulatory conditions justify termination. Currently, the Huntington CSA cannot be terminated based simply on increased renewable generation because the increased renewable generation must result in uneconomic

[284] PAC/400, Staples/41.
[285] Staff/600, Fox/9-10.
[286] 2017 TAM, Order No. 16-482 at 10-11.
[287] PAC/1000, Staples/18-19.
[288] CUB/200, Jenks/21.
[289] CUB/200, Jenks/21.

generation *directly* attributable to environmental regulation.[290] In other words, to trigger termination, the Company would need to show (1) that the increased renewable generation has caused conditions such that it is uneconomic to burn coal at Huntington and (2) that the economic conditions would not have occurred but for increased environmental regulations. Neither of these predicates has been satisfied at this time. PacifiCorp will continue to monitor and assess the market and regulatory environment to determine if and when it can prudently terminate the Huntington CSA.

I. AWEC's materials and supplies adjustment to BCC costs is unreasonable.

AWEC proposes a $1.18 million reduction to the materials and supplies expense included in the cost of BCC coal.[291] Staff supports AWEC's adjustment.[292] AWEC's only support for its adjustment is its claim that in the last three years the materials and supplies expense has been overstated by 32 percent and therefore AWEC adjusts the 2022 expense by that same amount.[293] AWEC's adjustment, however, is based on mischaracterizing the historical variance in materials and supplies expense and ignoring offsetting factors.

AWEC did not dispute that the reason the materials and supplies expense *appeared* overstated in the last three years is because the materials and supplies expenses were incurred both for coal production and reclamation activities and that reclamation activities were much higher in the last three years.[294] AWEC's analysis purporting to show overstated materials and supplies expense applied all the expense to coal production, which made it appear that the expense was over-stated. AWEC did not dispute these facts, which undermine the entire rationale for its adjustment.

AWEC also did not dispute the Company's evidence that offsetting factors substantially reduce AWEC's adjustment. AWEC examined only one expense item that it claimed (incorrectly) was overstated and ignored other expense items that were historically understated. Considering

[290] PAC/1200, Ralston/15.
[291] AWEC/200, Mullins/23.
[292] Staff/1000, Enright/12.
[293] AWEC/100, Mullins/22.
[294] PAC/1200, Ralston/16-19.

only the variance between the forecasted and actual "outside services" expense reduces AWEC's adjustment to [redacted].[295]

Overall BCC costs have been within [redacted] of the forecasted amount over the last five years, indicating that PacifiCorp's overall BCC costs estimates have been reasonable and accurate. The primary source of the overall cost variance in the last three years was volume variances, not the Company's inability to reasonably forecast BCC costs.[296]

J. Sierra Club's recommendations to adjust the Commission prudence standard for CSAs run contrary to prudent mine practices and Commission precedent.

Sierra Club has made several recommendations to modify the Commission's prudence standard for future CSAs and the minimum take provisions contained in these contracts. In particular, Sierra Club recommends that (1) minimum take levels should be set to 50 percent or less of projected consumption, (2) all CSAs should last no more than two years, and (3) all CSAs should include renegotiation provisions to avoid or reduce minimum take provisions if triggering conditions arise.[297] The Commission should reject Sierra Club's recommendations because they ignore commercial realities and would result in higher costs for customers. In addition, the Commission does not have authority to make business decisions for a utility or micromanage its operations as Sierra Club suggests.[298]

First, requiring minimum takes that are less than 50 percent is contrary to standard industry practice.[299] Indeed, Sierra Club could produce no evidence of utilities executing CSAs with 50 percent minimum take levels.[300] Executing CSAs with such a low minimum take level would increase price risks and hinder coal suppliers from investing in future production, further weaking coal supply markets.[301] Nearly all PacifiCorp's coal plants are in illiquid coal markets across the

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[295] PAC/1200, Ralston/16-19.
[296] PAC/1200, Ralston/16-19.
[297] Sierra Club/100, Burgess/3, 35, 45, 48.
[298] *See In re the Tariffs Filed by Juniper Util. Co. for Water Serv.*, Docket No. UW 65/68, Order No. 00-543 at 8 (Sept. 14, 2000) (explaining that the Commission does not have the authority "to make business decisions for a utility regarding the advantages and disadvantages of a particular business proposal or plan").
[299] PAC/500, Schwartz/30.
[300] PAC/1300, Schwartz/2.
[301] PAC/600, Ralston/34.

western United States.[302] Reducing CSA minimums below 50 percent of expected production would require additional one-time purchases of coal, increasing transportation and coal costs for customers.[303] In these illiquid markets, utilities generally purchase 70-to-95 percent of coal through CSA minimums.[304] Setting minimum takes as low as 50 percent is unheard of in the industry and would constitute a highly risky fueling strategy for customers.[305] In the 2020 Energy Cost Adjustment Clause (ECAC), Sierra Club recommended that the California Public Utilities Commission (CPUC) "establish a heightened standard of review for contracts that have a minimum tonnage amount set at greater than 50% of the forecasted generation for the plant(s) at issue," and the CPUC rejected the recommendation.[306]

Second, making a per se requirement that all CSAs must be two years or less would hinder PacifiCorp's ability to negotiate low coal prices for its facilities in illiquid markets. Most of the Company's facilities are located with limited suppliers and transportation options.[307] These facilities require CSAs longer than two years to induce investment by mine operators and reduce risk with high-cost emergency purchases.[308] By limiting PacifiCorp to only enter into two-year CSAs, the Commission would ultimately increase costs for customers and decrease competition in the already small, illiquid coal markets.

Finally, PacifiCorp has already been successful in negotiating CSAs that contain provisions that reduce minimum take obligations depending on triggering conditions.[309] In the past, these provisions have included environmental triggering events, force majeure clauses, and coal quality excursions.[310] PacifiCorp has successfully exercised these provisions in existing CSAs by, for

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[302] PAC/1200, Ralston/7.
[303] *See* PAC/500, Schwartz/12.
[304] PAC/500, Schwartz/13.
[305] PAC/500, Schwartz/30.
[306] PAC/1200, Ralston/23 (citing *In re Application of PacifiCorp (U901E) for Approval of its 2020 Energy Cost Adjustment Mechanism Clause and Greenhouse Gas Related Forecast and Reconciliation of Costs and Revenues*, CPUC Application 19-08-002, D.20-12-004 at 7 (Dec. 7, 2020)).
[307] *See, e.g.*, PAC/600, Ralston/39 (discussing the limited supply options for Naughton and Jim Bridger); PAC/700, MacNeil/10 (discussing the limited supply options for Hunter).
[308] PAC/500, Schwartz/13-14.
[309] PAC/600, Ralston/36-37.
[310] PAC/600, Ralston/37.

example, reducing the minimum for the Naughton plant by [redacted].[311] Even though the Company already pursues these provisions in its CSAs, requiring their particular inclusion through a Commission mandate could potentially hinder PacifiCorp's ability to negotiate least-cost, least-risk CSAs.

K. Sierra Club's recommendation to require filing of all CSAs and affiliate mine plans in future TAMs is unnecessary and unduly burdensome.

Sierra Club recommends that PacifiCorp should provide copies of its CSAs and affiliate mine plans in each TAM filing, and Staff supports this position.[312] While the Company is committed to providing parties access to CSAs through the Modified Protective Order in this proceeding,[313] providing copies of CSAs is problematic due to the extreme commercial sensitivity of these documents. Moreover, the Modified Protective Order specifically allows parties to seek copies of relevant sections of any CSA for use in developing their testimony.[314] Neither Staff nor Sierra Club have explained why this provision is insufficient.

Coal suppliers consider these contracts to be extremely sensitive, and PacifiCorp must maintain substantial protections for these highly confidential documents. Each of these CSAs contain clauses that require the Company to maintain the confidentiality of the contract.[315] Violating these confidentiality provisions would expose PacifiCorp to litigation and breach of contract damages. Ultimately, dissemination of CSAs could damage the Company's relationships with counterparties and affect PacifiCorp's ability to conduct future negotiations, increasing the risk of higher costs for customers.[316]

Apart from confidentiality concerns, disclosure of the terms of a coal supply or transportation agreement could also seriously harm PacifiCorp's competitive position during future negotiations. The Company's coal facilities are all located in limited, highly competitive

[311] PAC/600, Ralston/37.
[312] Sierra Club/100, Burgess/3-4; Staff/1400, Anderson/6-7.
[313] *In re PacifiCorp, dba Pac. Power, 2022 Transition Adjustment Mechanism*, Docket No. UE 390, Order No. 21-086 at 1 (Mar. 23, 2021) (finding good cause to issue a modified protective order in this case for PacifiCorp's "coal fueling information"); *see also* PAC/1200, Ralston/7-8.
[314] PAC/1200, Ralston/7-8.
[315] PAC/1200, Ralston/6.
[316] PAC/1200, Ralston/7.

coal markets with very few suppliers and coal transporters.[317] Several of PacifiCorp's facilities are captive to specific coal suppliers and have no access to rail services to reach other coal markets.[318] Public disclosure of these terms would put PacifiCorp, its suppliers, the railroads, and trucking companies at a competitive disadvantage and increase cost risks to customers. Increasing these commercial and legal risks to provide copies of documents already accessible through a modified protective order is unnecessary and potentially harmful to PacifiCorp and customers.

L. Sierra Club's adjustment to Jim Bridger coal costs is contrary to basic economic principles and relies on faulty assumptions.

Sierra Club recommends a $[redacted] reduction in Jim Bridger fuel expense based on Sierra Club's mistaken and unsupported claim that PacifiCorp could dramatically reduce generation at Jim Bridger by using average price dispatch.[319] Sierra Club's arguments, however, rely on highly unconventional dispatch practices that would ultimately increase costs for customers. Sierra Club also mischaracterizes the level of fixed costs at BCC that could be avoided if the Company were to dramatically reduce generation at the Jim Bridger plant consistent with Sierra Club's recommendation.

1. Average cost dispatch is contrary to industry standards, basic economic principles, and Commission precedent.

GRID dispatches coal plants on an incremental (or marginal) cost basis to optimize NPC while accounting for system constraints such as transmission and reliability concerns.[320] Incremental costs are defined as the cost to increase production of a generation unit by one MWh.[321] If the cost to generate an additional MWh at a coal plant is less than the current market price of electricity, GRID increases the plant's dispatch. Once GRID calculates the total generation from each plant, the total cost of fuel is then spread over the total fuel volume to develop the average price, which is then used for setting rates.[322] Incremental cost dispatch is entirely

[317] PAC/1200, Ralston/7.
[318] PAC/1200, Ralston/7.
[319] Sierra Club/200, Burgess/25.
[320] PAC/400, Staples/50.
[321] PAC/400, Staples/50.
[322] PAC/400, Staples/50.

uncontroversial in the energy industry and PacifiCorp models incremental cost dispatch in every state.[323]

Incremental cost dispatch is standard industry practice and consistent with basic economic principles because it appropriately recognizes that dispatch decisions should be based on the variable costs of production.[324] As PacifiCorp explained at hearing, the incremental cost is "the cost minimizing solution for customers" because it "acknowledge[s] that there are certain costs that are sunk, so they don't vary with production" and therefore those sunk, or fixed, costs should not be considered when deciding whether to produce an additional MWh.[325]

In the context of coal plant dispatch, incremental cost appropriately reflects the economics inherent to minimum take obligations. PacifiCorp does not use an average price as a dispatch price in short-term forecasts like the TAM because the cost of coal in a take-or-pay volume tier is not avoidable.[326] In other words, the cost for coal in a minimum take volume tier is a sunk cost, meaning that the Company cannot avoid the expenses regardless of its actions.[327] Because of this basic economic fact, the marginal cost of fuel in the minimum take volume tier is zero.[328] If the Company was forced to decrement coal generation below the minimum take level, it would also be forced to replace that generation with market purchases or other generation.[329] The net result of this modeling change would be to slightly reduce coal generation while increasing overall costs because customers would pay for coal that was not burned *and* replacement energy.[330] PacifiCorp's expert witness, Mr. Schwartz explained that PacifiCorp's use of incremental cost dispatch is consistent with the industry, where utilities dispatch their plants based on the

[323] Confidential Evid. Tr. 35:1-6.
[324] Confidential Evid. Tr. 34:11-25.
[325] Confidential Evid. Tr. 34:19-25.
[326] PAC/400, Staples/52-53.
[327] PAC/400, Staples/53.
[328] *See* PAC/400, Staples/51 ("[I]n a short-term forecast, such as the TAM, the Company uses an iterative process to arrive at a marginal fuel cost that produces a result where the generation at each plant meets the minimum purchase obligations present in the coal supply and transportation agreements.").
[329] PAC/400, Staples/53.
[330] PAC/400, Staples/53.

incremental cost so that "[c]ustomers benefit from least-cost dispatch as utilities only include the variable cost of fuel in the decision whether to operate a power plant [.]"[331]

Sierra Club recommends that PacifiCorp use average, rather than marginal, cost when determining coal plant dispatch.[332] The average cost of production is the ratio of the total cost of production to the total energy produced.[333] Using average cost dispatch for coal plants fundamentally distorts the plant's economics because it effectively ignores the presence of fixed costs that cannot be avoided.[334] If a plant would dispatch based on the incremental cost but would not have dispatched based on the average cost, then the "most economic decision is to dispatch the power plant even though the fuel cost charged to the customer is greater than the fuel cost used for dispatch purposes" because the additional revenue earned by dispatching the plant will help offset the fixed costs of the minimum take obligation.[335] The record in this case demonstrates that the use of average cost dispatch increases customer costs.[336]

In the 2017 TAM, the Commission approved the Company's incremental cost approach to modeling CSAs with minimum take provisions.[337] When Sierra Club raised this identical argument in the Company's 2020 ECAC proceeding, the CPUC rejected it outright, concluding that "Sierra Club's recommendation to use average costs in the dispatch of PacifiCorp's coal fleet [was] unsupported by the record and *contrary to basic economic principles*."[338]

By ignoring the Company's least-cost, least risk solution to modeling coal generation, Sierra Club recommends an adjustment to Jim Bridger based on average cost dispatch that neither the Commission, nor any other jurisdiction in which PacifiCorp operates, has ever required. Sierra Club's adjustment should be rejected based on basic economic principles alone.

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[331] PAC/500, Schwartz/16.
[332] Sierra Club/200, Burgess/20.
[333] PAC/400, Staples/50.
[334] PAC/1200, Ralston/23-24.
[335] PAC/500, Schwartz/16.
[336] PAC/400, Staples/52-53; *see also* Staff/600, Fox/7-8 (showing how the informational run using average cost methodology increased costs).
[337] *See* 2017 TAM, Order No. 16-482 at 10-11.
[338] *In re Application of PacifiCorp (U901E) for Approval of its 2020 Energy Cost Adjustment Mechanism Clause and Greenhouse Gas Related Forecast and Reconciliation of Costs and Revenues*, CPUC Application 19-08-002, D.20-12-004 at 7 (Dec. 7, 2020).

2. Sierra Club's adjustment ignores significant fixed costs at BCC that could not be avoided if production dramatically decreased.

Sierra Club argues that minimum take requirements are not present at the Jim Bridger plant because the plant's primary coal supply is BCC, which has no conventional minimum take obligation.[339] While coal from the BCC mine does not have a minimum take level, the mine does have fixed costs that operate similar to minimum take provisions present in PacifiCorp's CSAs.[340] Sierra Club's adjustment largely assumes away BCC's fixed costs and proposes a [redacted] percent reduction in BCC production.[341] By ignoring significant fixed costs that would be incurred even with a dramatic reduction to BCC production, Sierra Club ignores the operational realities associated with its adjustment.[342] Implementing Sierra Club's recommended reduction to BCC production would actually increase customer costs and should therefore be rejected.[343]

To develop the incremental coal costs at BCC, the Company develops different mine plans to identify expected coal costs at differing targeted production levels.[344] The cost differential between the plans is divided by the tonnage differential between the plans to determine BCC's expected incremental costs.[345] BCC has significant fixed costs that are incurred regardless of production volume. PacifiCorp's expert identified three reasons that costs do not vary with production for mines like BCC: (1) certain "wholly fixed" costs are "incurred regardless of the level of operations, such as property taxes"; (2) "there are many activities that must be performed at the same level regardless of the level of operations, such as safety and environmental compliance," which include "labor and supplies, which may appear to be variable cost categories, but the activity level is fixed"; and (3) the "mining is most efficient, and costs are lowest, when the equipment is being operated at design capacity" and therefore "[r]educing production below this level will not reduce costs proportionately."[346] In this case, PacifiCorp identified $[redacted]

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[339] Sierra Club/100, Burgess/31 (Confidential Table 6).
[340] PAC/400, Staples/63.
[341] Sierra Club/200, Burgess/24 n.40.
[342] PAC/1200, Ralston/39.
[343] PAC/1200, Ralston/36.
[344] PAC/1200, Ralston/36-37.
[345] PAC/600, Ralston/45.
[346] PAC/500, Schwartz/18-19.

in "wholly identifiable fixed costs" and an additional $[redacted] in costs that should be considered fixed for the purposes of a one-year time scale, such as labor and benefits; material and supplies; electricity, and other miscellaneous costs.[347] In all, PacifiCorp identified *at least* $[redacted] in total fixed costs for BCC for 2022, while acknowledging that the estimate was conservative.[348]

Sierra Club's adjustment accounted for only the "wholly identifiable fixed costs" of $[redacted] and ignored the other $[redacted] identified by the Company.[349] To explain this omission, Sierra Club claimed that PacifiCorp did not provide a numerical estimate for "embedded" fixed costs, so Sierra Club presumed that any additional fixed costs above $[redacted] were *de minimis*.[350] But PacifiCorp did provide a direct figure identifying $[redacted] of additional fixed costs, which can hardly be characterized as *de minimis*.[351]

Sierra Club has also mischaracterized other aspects of BCC's costs to reach its Jim Bridger adjustment. For example, Sierra Club argues that its average cost model run outlining $[redacted] in coal fuel expenditures will be "more than sufficient" to cover scaled down production at BCC.[352] But this calculation fails to use the actual 2022 TAM calculations for Jim Bridger fueling costs of $180.6 million creating a $[redacted] deficit from projected NPC.[353]

Sierra Club provides an example that purports to show how dramatically reducing BCC production could lead to lower overall NPC.[354] But Sierra Club's example incorrectly assumed that dramatically reducing mine production would not change the per-unit price of coal, which effectively ignores the impact of fixed costs.[355] Correcting only this error demonstrates that reducing BCC production comparable to Sierra Club's recommendation increases costs by nearly 10 percent.[356]

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[347] Sierra Club/112, Burgess/6.
[348] PAC/400, Staples/65.
[349] Sierra Club/100, Burgess/56 (Confidential Table 9).
[350] Sierra Club/200, Burgess/2.
[351] PAC/1200, Ralston/26.
[352] Sierra Club/200, Burgess/23.
[353] PAC/1000, Staples/20.
[354] Siera Club/200, Burgess/19 (Confidential Table 2).
[355] PAC/1200, Ralston/39.
[356] PAC/1200, Ralston/39-41.

Sierra Club's recommendation to dramatically reduce BCC production also fails to take into consideration the operational realities of the mine. For example, Sierra Club treats BCC's workforce as a variable cost thereby assuming that the Company would effectively layoff half its work force to reduce production.[357] BCC must maintain a qualified and experienced workforce to operate the mine to conduct steady operations and use the coal inventory fluctuations to support the variability in coal burn.[358] In actual operations, PacifiCorp cannot lay off a substantial portion of its BCC workforce to drastically ramp down production only to rehire the same miners in 2023, if it needed to ramp up coal production in subsequent years.[359] PacifiCorp has also been able to prudently manage its BCC labor force in times of low production by shifting labor to reclamation activities that must occur regardless of lower production volumes.[360] Adopting Sierra Club's approach to mining operations would hinder PacifiCorp's ability to efficiently mine coal and undertake reclamation, resulting in higher costs for customers.

3. The regulatory treatment of BCC costs ensures reasonableness.

Sierra Club claims that PacifiCorp has no incentive to contain BCC costs and suggests that costs are excessive as a result.[361] This argument entirely ignores the TAM, where BCC costs are regularly assessed and where the Commission has repeatedly affirmed the reasonableness of the Company's Jim Bridger fueling strategy and BCC costs. In the 2014 TAM, the Commission rejected an adjustment that would have repriced BCC coal using Black Butte pricing as a market alternative. In that case, the Commission found that PacifiCorp's approach to fuel supply was reasonable and that the "Commission has historically approached the company's affiliate transactions with a cost-based approach, and that in the case of BCC coal, there is no possibility

[357] PAC/1200, Ralston/29-30.
[358] PAC/500, Schwartz/18-20.
[359] PAC/1200, Ralston/30.
[360] PAC/1200, Ralston/30.
[361] Sierra Club/200, Burgess/8.

of utility-affiliate cross-subsidization."[362] Then, in the 2017 TAM, the Commission found that the Company reasonably considered market alternatives to BCC coal and rejected an argument to reprice BCC coal using a market alternative.[363] In the 2019 TAM, PacifiCorp filed a Long-Term Fuel Supply Plan for the Jim Bridger Plant[364] and then updated the plan without objection in the 2020 TAM.[365] The Commission has regularly scrutinized BCC costs to ensure that they remain reasonable, contrary to Sierra Club's claims.

M. Sierra Club's additional recommendations rely on false comparisons, overly simplistic analyses, and a disregard of established economic principles.

Sierra Club proposes several specific recommendations specific to the 2022 TAM and some broader recommendations for future changes to the TAM. Outside of Sierra Club's proposal to require the filing of CSAs and affiliate mine plans discussed above, it recommends that:

- The Commission should ensure NPC projections reflect the true nature of incremental fueling costs, especially when there is no pre-existing minimum take or approved contract;
- The Commission should only approve 2022 TAM rates on an interim basis for open fuel supplies at Jim Bridger, Naughton, and Dave Johnson until the Commission reviews the Company's CSAs in a supplemental filing, including additional GRID runs;
- The Commission should defer any final approval of fixed costs for BCC coal pending a prudence review of these costs;
- The Commission should require the Company to provide a tracking report detailing its daily unit commitment and dispatch decisions for all its thermal plants throughout 2022;
- The Commission should require PacifiCorp to include a report on the steps it has taken to reduce BCC mine costs and replace BCC coal from its Jim Bridger fueling strategy; and
- The Commission should conduct a separate comparison of each cost recovery mechanism to ensure there are no duplicative costs for the BCC mine in base rates and NPC.[366]

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[362] *In re PacifiCorp, dba Pac. Power, 2014 Transition Adjustment Mechanism*, Docket No. UE 264, Order No. 13-387 at 6 (Oct. 28, 2013) [hereinafter 2014 TAM].
[363] 2017 TAM, Order No. 16-482 at 6-8.
[364] 2019 TAM, Docket No. UE 339, PAC/204 (Mar. 30, 2018).
[365] 2020 TAM, Docket No. UE 356, PAC/201 (Apr. 1, 2019).
[366] Sierra Club/100, Burgess/2-3.

Many of these recommendations are outside the scope of the TAM and are more appropriate for the Company's IRP or long-term fuel plan processes. As discussed above, the Company is already achieving substantial reductions in coal generation though its IRP, low minimum burns, and increased renewable generation without sacrificing reliability or increasing costs.[367]

Sierra Club's proposal to conduct a comparison of the Company's base rates and TAM to prohibit double recovery of BCC depreciation costs is both outside the scope of the TAM and devoid of any factual premise. Similarly, Sierra Club's claims that it is inappropriate for the Company's iOpt and Power Costs Incorporated forecasts to assume BCC supplemental pricing for all coal consumed at Jim Bridger do not belong in the TAM.[368] PacifiCorp has already provided its projected operating costs in its GRID report for the 2022 TAM.[369] Further information on whether individual coal units were "economically cycled" or cycled during actual dispatch should be reserved for PacifiCorp's PCAM proceeding, which focuses on the differences between projected and actual operation costs.[370] As for Sierra Club's proposal to require an accounting of BCC costs in future TAMs, this suggestion is based on incorrect assumptions about BCC fixed costs and the Company's prudent mine operations. As discussed above, PacifiCorp has demonstrated that its modeling of BCC coal and mine costs are designed to optimize NPC and lower costs for customers.[371] To the extent that Sierra Club's reporting requirements are based on long-term fueling decisions for Jim Bridger or mine operations at BCC, these discussions should be reserved for PacifiCorp's IRP or long-term fuel plan process.

In summary, Sierra Club's recommendations should be rejected as unnecessary, harmful to customers, and outside the scope of the TAM.

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[367] PAC/400, Staples/48.
[368] Sierra Club/100, Burgess/69-70.
[369] PAC/400, Staples/72.
[370] *See In re PacifiCorp, dba Pac. Power, Request for a Gen. Rate Revision*, Docket No. UE 246, Order No. 12-493 at 8 (Dec. 20, 2012) (noting that the goal of the PCAM is "to collect or credit the differences between actual net power costs . . . and the forecasted net power costs approved in the TAM and recovered in rates").
[371] *See* PAC/400, Staples/72. ("BCC Coal costs are properly accounted for in the GRID model and any further discussion of the prudence of these costs should be addressed in PacifiCorp's long-term mine plan or IRP process.").

N. The COOC has a floor at zero and should not go negative.

When the Commission adopted the COOC in docket UE 267, it concluded that the "consumer opt-out *charge* is necessary pursuant to implementation of the state's direct access laws" and that the charge "would protect other customers from cost-shifting."[372] Since the Commission adopted the COOC, it has always acted as a charge to prevent direct access customers from shifting stranded costs onto remaining customers as they leave PacifiCorp's system.[373] This year, however, the Commission-approved calculation for the COOC is projected to be a zero charge.[374] Calpine has opposed PacifiCorp's methodology for the COOC and believes that the Company improperly constrained the calculation from going negative.[375] Essentially, Calpine believes that the Customer Opt-Out *Charge* should now become the Customer Opt-Out *Credit*, effectively forcing remaining customers to pay direct access customers when they leave.[376]

AWEC has also joined Calpine's position to allow the COOC to become a credit for the 2022 TAM.[377] Staff agrees that the COOC should be allowed to go negative[378] but also suggests that the Commission "make a recommendation" in this docket while allowing for a more thorough consideration of the issue in the Commission's investigation into direct access, docket UM 2024.[379]

CUB's position is that the COOC be set to zero in this proceeding if its value becomes negative and that the issue be addressed more holistically in docket UM 2024 along with all other policy issues related to direct access.[380] PacifiCorp agrees with CUB that the COOC was never meant to become a credit, and so the Commission should not allow the COOC to go negative in this proceeding. However, the Company also believes that the COOC could be evaluated in docket

[372] *In re PacifiCorp, dba Pac. Power, Transition Adjustment, Five-Year Cost of Serv. Opt-out*, Docket No. UE 267, Order No. 15-060 at 6 (Feb. 24, 2015) (emphasis added).
[373] PAC/900, Meredith/4.
[374] PAC/900, Meredith/3-4.
[375] Calpine Solutions/100, Higgins/16.
[376] PAC/900, Meredith/4-6.
[377] AWEC/200, Mullins/27.
[378] Staff/1300, Gibbens/10.
[379] Staff/1300, Gibbens/9-10.
[380] CUB/200, Jenks/29.

UM 2024 and does not oppose the transfer of this issue to that docket for a fulsome evaluation of the policy issues surrounding the COOC.[381]

1. When the Commission adopted the COOC, it never intended the charge to become a credit.

When PacifiCorp presented the COOC in docket UE 267, the Company was clear it never intended the charge to become a credit.[382] The Company argued that the elimination of the COOC was contrary to direct access laws prohibiting cost-shifting.[383] The Commission agreed with PacifiCorp, stipulating that a primary reason for the COOC was to "protect other customers from cost-shifting."[384]

These same reasons for the COOC to remain a charge are as relevant today as they were in 2015. The Consumer Opt-Out Charge was labeled a "charge" for a reason. The Commission designed the COOC as a mechanism to recover some of the stranded costs of the fixed generation system that a departing participant would no longer pay after its five-year transition period. To the extent that the forecast value of freed-up generation offsets generation costs, then the "charge" should be zero.[385] In docket UM 2024, CUB has submitted comments that argue the direct access program has already resulted in unwarranted cost-shifting because program participants' wholesale energy purchases do not capture the capital costs associated with power generation.[386] If the Commission allows the COOC to drop below zero, it will exacerbate this problem. The Commission should not allow the COOC to negatively impact a utility's cost-of-service customers at the expense of a small subset of large industrial customers.[387]

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[381] PAC/1500, Meredith/5.
[382] CUB/200, Jenks/25.
[383] *See* ORS 757.607(1) (preventing "unwarranted" cost shifting from direct access); *see also* OAR 860-038-0160(1).
[384] Order No. 15-060 at 6.
[385] PAC/900, Meredith/3-4.
[386] CUB/200, Jenks/26.
[387] CUB/200, Jenks/27.

2. Allowing the COOC to go negative is bad policy and has broader implications that should be addressed holistically in docket UM 2024.

If the Commission is inclined to agree that the COOC could potentially act as a credit paid by cost-of-service customers, then it should defer making that decision until the operation of the COOC can be addressed holistically in docket UM 2024. Staff and CUB have already indicated that setting the COOC below zero implicates other direct access policy issues and should be discussed in the context of related direct access concerns in docket UM 2024.[388] Setting the COOC below zero is bad policy because the charge aims to prevent cost-shifting to non-direct access customers. Providing permanent direct access customers with a bonus payment under the COOC weighs heavily against the interests of non-participating customers.[389] Considering the impact a negative COOC would have on cost-shifting and other aspects of Oregon's direct access program, it makes sense for the Commission to address the issue in that docket.

O. Renewable Energy Certificate (REC) retirement for Electricity Service Suppliers (ESS)

As a result of the changes resulting from House Bill 2021 that allows bundled RECs to be retired by the utility on behalf of an ESS, PacifiCorp and Calpine are proposing a slightly different process for handling the RECs for direct access customers.[390] Specifically, PacifiCorp would prefer to implement a process using a WREGIS retirement subaccount that is specific to each ESS and renewable portfolio standard (RPS) compliance year. PacifiCorp will then transfer into that retirement subaccount the bundled and unbundled RECs necessary to meet the RPS obligation for the customers of the ESS that are paying transition adjustment charges to PacifiCorp.[391] This process is the least administratively burden and most efficient process for handling RECs for ESSs' direct access customers.[392] No party has objected to this proposal.

[388] Staff/1300, Gibbens/10; CUB/200, Jenks/28-29.
[389] PAC/1500, Meredith/4-5.
[390] PAC/1400, Wiencke/1.
[391] PAC/1400, Wiencke/1-2.
[392] PAC/1400, Wiencke/1-2.

P. 2023 TAM Filing Date

As the Company nears its transition to the Aurora model in next year's TAM, CUB and Staff have proposed moving up the 2023 TAM filing deadline to give Staff and stakeholders more time to review the new NPC model.[393] CUB supports a filing date of March 1, 2022, to allow PacifiCorp to implement the December 31 forward price curve in NPC forecasts.[394] Staff, on the other hand, supports an earlier filing date of February 14, 2022, based on the date when PacifiCorp filed its 2021 TAM.[395] Staff then recommends allowing the Company to file an update on April 1, 2022, with updated inputs.[396]

PacifiCorp is amenable to an earlier filing date but is concerned that an earlier filing date would not allow the Company time to conduct more workshops discussing and presenting the Aurora model before the filing deadline.[397] If the Commission does decide to move up the TAM filing, the Company may need to conduct some workshops after it makes its initial TAM filing.

Moving up the TAM filing also increases the administrative burden on the Company. The Commission should reject Staff's proposal to require an April 1 update because this filing would include the same price curves as a February or March filing, eliminating much of the potential benefit.[398] The Company also requests that the Commission still allow PacifiCorp to provide the Transition Adjustment calculation for Schedule 296 on May 30 to reduce the administrative burden.[399]

[393] CUB/200, Jenks/21-22; Staff/1000, Enright/13.
[394] CUB/200, Jenks/22.
[395] Staff/1000, Enright/14.
[396] Staff/1000, Enright/14.
[397] PAC/1000, Staples/57.
[398] PAC/1000, Staples/56.
[399] PAC/1000, Staples/57.

III. CONCLUSION

The Company respectfully requests that the Commission approve PacifiCorp's proposed 2022 TAM increase of approximately $1.1 million, or less than 0.1 percent. The Company's filing includes significant customer benefits from the EIM and the Company's recent investments in renewable generation, reflects a major reduction in coal generation and new CSAs with favorable terms and conditions for customers, and adheres to past TAM precedents, the TAM Guidelines, and relevant provisions of past TAM stipulations. It includes only one major modeling change, a reasonable revision to market caps to mitigate the gross over-estimation of off-system sales identified by the Commission in the Company's 2020 Rate Case. To address the Company's persistent under-recovery of NPC in the TAM, the Commission should approve average-of-averages market caps. The Commission should also reject the parties' adjustments which will perpetuate the Company's NPC under-recovery, decrease the Company's flexibility to manage the complex transition from thermal to renewable resources, and ultimately make it more difficult for the Company to maintain reliable service and affordable rates.

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