ORDER NO. 17 444

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 323

In the Matter of PACIFICORP, dba PACIFIC POWER, 2018 Transition Adjustment Mechanism.	ORDER

DISPOSITION: NET POWER COSTS APPROVED SUBJECT TO ADJUSTMENTS

I. INTRODUCTION

In this order, we approve PacifiCorp's 2018 net power costs (NPC) forecast, subject to two modifications. We modify the Day-Ahead/Real-Time (DA/RT) adjustment to use data from years following PacifiCorp's participation in the Energy Imbalance Market (EIM), and modify the company's qualifying facility (QF) forecast to use a rolling three-year average contract delay rate.

To address other issues raised by the parties, we also require activities on four other matters to be completed before PacifiCorp files its 2019 Transition Adjustment Mechanism (TAM). First, we require the company to complete a limited GRID validation process. To ensure this validation process is useful to the parties, we direct the parties to discuss the scope and mechanics of the validation process. We ask Staff to provide a status report on the discussions at a public meeting no later than the first public meeting in January 2018.

Second, we direct various actions on coal issues. At the outset, we require PacifiCorp to include in the 2019 TAM an updated 2010 coal inventory report. We also accept PacifiCorp's offer to conduct party workshops to address coal contract supply issues and including variable operations and maintenance (O&M) in the TAM. In addition to those issues, we also ask the parties to address coal plant economic outage modeling. We direct PacifiCorp to make a presentation at a public meeting before the 2019 TAM summarizing the discussions from the coal workshops, and to specifically describe any proposals identified.

Third, we accept PacifiCorp's offer to conduct a party workshop before the 2019 TAM filing to address renewable energy credit (REC) transfers to Electricity Service Suppliers (ESS) that serve opt-out customers under the one- or three-year direct access programs. We add a reporting requirement for the 2019 TAM and direct the company to present its best proposal for REC transfers in initial testimony. This testimony will allow parties to weigh in and build a full record on this issue, and enable us to decide whether REC transfers are practical and feasible.

Finally, we provide new guidelines for PacifiCorp's opt-out charge that applies to direct access customers electing the five-year program, and we direct the company to demonstrate that its opt-out charge complies with our guidelines in its 2019 TAM filing.

II. BACKGROUND

PacifiCorp is a public utility in the State of Oregon within the meaning of ORS 757.005. PacifiCorp provides electric service to approximately 574,000 retail customers within the state, and is subject to the Commission's jurisdiction with respect to the prices and terms of electric service for its Oregon retail customers.

Each year, PacifiCorp updates its NPC and sets the transition adjustments for direct access customers through the TAM.[1] On March 31, 2017, PacifiCorp filed Advice No. 17-002, as well as testimony and exhibits, to initiate the company's 2018 TAM proceeding.[2] Through updated filings, PacifiCorp estimates NPC of $370.2 million on an Oregon-allocated basis. This is a rate increase of $7.9 million, or 0.6 percent, over last year's forecast of power costs for 2017, subject to the company's indicative and final updates.

PacifiCorp's NPC are generally comprised of fuel expenses, wholesale purchased power expenses, and wheeling expenses, less wholesale sales revenue. The company explains, however, that the 2018 TAM rate increase is largely due to other factors, including a slight decrease in Oregon's load forecast, a slight increase in Oregon's state allocation factors (Oregon's share of load relative to PacifiCorp's other states) and a decrease in production tax credits (PTCs).[3]

To calculate its NPC, PacifiCorp uses GRID, its production cost model that simulates the dispatch of the company's power system on an hourly basis. The NPC report is the major output of the GRID model. The company updates all GRID input assumptions to produce the TAM, including system load, wholesale sales and purchase contracts for electricity, natural gas and wheeling, market prices for electricity and natural gas (using an official forward

[1] PacifiCorp posts indicative transition adjustments for potential direct access customers just before the November open enrollment window. The company's updated power costs are effective January 1, 2018.
[2] TAMs are referred to by test period, not by the year of filing. This TAM was filed and analyzed in 2017, but is referred to as the 2018 TAM because it uses 2018 as a test period. Previous TAMs are also referred to by their test period.
[3] In 2018, PTCs are expiring at two of PacifiCorp's larger wind facilities with a revenue requirement impact of $5.8 million. PAC/100, Wilding/6; PAC/106, Wilding/1 (showing PTC expiration dates from Goodnoe and Marengo wind projects of 12/17/2017 and 8/2/2017, respectively).

price curve), fuel expenses, and the characteristics and availability of generation facilities. The TAM is updated three times after the company's initial filing, with the reply update, November indicative update, and November final update using the most recent official price curves that may significantly impact the final rate impact. The 2018 TAM forecasts NPC of $25.56 per MWh, compared to the 2017 final forecast of $25.36 per MWh.

Over the course of this proceeding, PacifiCorp, the Industrial Customers of Northwest Utilities (ICNU), the Oregon Citizens' Utility Board (CUB), Calpine Energy Solutions, Sierra Club, and the Commission Staff filed five rounds of testimony and multiple rounds of briefing. We conducted an evidentiary hearing on August 31, 2017.

III. DISCUSSION

A. Overview

In response to concerns raised in PacifiCorp's 2017 TAM proceeding, we directed the company, intervenors, and Staff to participate in workshops to address three NPC issues and one direct access issue: the DA/RT adjustment, EIM benefits, fueling plans for the Jim Bridger coal plant, and valuing RECs for direct access customers. At our March 21, 2017 Regular Public Meeting, Staff reported that PacifiCorp, Staff and parties participated in good faith in all three workshops with the objective of enhancing the understanding of PacifiCorp's GRID modeling choices. Staff, along with CUB, reported that the workshops were helpful and productive outside of the contested case process.[4]

In this 2018 proceeding, many disputes remain with regard to PacifiCorp's GRID modeling and forecast. Staff and ICNU continue to challenge the DA/RT adjustment, Staff challenges the EIM benefits calculation, and CUB challenges the qualifying facility (QF) forecast costs. Staff and ICNU also request model validation. Staff challenges coal issues while Sierra Club has agreed to workshops with the company. Calpine challenges the REC valuation methodology and the opt-out charge calculation. We address each issue below, and make more specific findings than we were able to the last two years, thanks to the parties' more detailed testimony this year that appears to partially reflect analytical work that began in workshops.

[4] PAC/100, Wilding/18 (stating that PAC/109 is the company's letter describing the 3 modeling changes agreed to at the workshops and PAC/108 is a step-log of GRID model and input changes to increase the transparency of the TAM). We grant ICNU's request to take official notice under OAR 860-001-0460(1)(d) of CUB's Comments describing the workshops in Docket No. UE 307 at 1 (Jan 23, 2017)

B. Legal Standard

Before we turn to the issues presented, we briefly address the applicable legal standards. PacifiCorp begins this proceeding with two burdens. First, the company bears the initial burden of production—that is, presenting evidence to support its request. This burden of production then shifts to the party or parties who oppose including the costs in the utility's revenue requirement. Second, PacifiCorp bears the burden of persuasion to show that its proposal is fair and will result in rates that are just and reasonable. This burden remains with the utility throughout the proceeding.[5]

To reach a determination on whether proposed rates are just and reasonable, we examine the record as a whole and make decisions based on a preponderance of the evidence.

C. Model Validation

1. Parties' Positions

Both Staff and ICNU contend that PacifiCorp should conduct a backcast, or model validation of GRID. Both question the accuracy of GRID and believe that some form of validation is necessary. Staff believes the company should conduct GRID runs using actual historical input values, so that parties can compare the results to historic realized NPC. Staff believes this evaluation will explain whether forecast errors are related to inputs (such as gas prices) or model specification (such as missing model inputs or inappropriate model mechanics).[6]

PacifiCorp supports model validation, but states that backcasting is not a useful technique and is not necessary to address GRID's accuracy. At the outset, the company explains that, although GRID has historically understated its NPC, the 2016 forecast was the most accurate compared to actual NPC. The company attributes this accuracy to modeling changes approved in the last two TAM proceedings. Instead, PacifiCorp believes the best method of addressing model accuracy is to compare forecast NPC to actual NPC, similar to what occurs in the Power Cost Adjustment Mechanism (PCAM), and that the parties should conduct a more thorough analysis of the line-by-line differences between TAM and PCAM values.

In addition, PacifiCorp also contends that model validation would be problematic because GRID operates differently than PacifiCorp's actual system, GRID has perfect foresight, and NPC forecast is normalized. PacifiCorp also maintains that model validation is administratively burdensome if the company must re-run GRID using actual historical values

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[5] *See,* e.g., *In the Matter of Portland General Electric Company Application to Amortize the Boardman Deferral*, Docket No. UE 196, Order No. 09-046 at 7-8 (Feb 5, 2009); *see also In the Matter of Portland General Electric Company 2012 Annual Power Cost Update Tariff (Schedule 125)*, Docket No. UE 228, Order No. 11-432 at 3 (Nov 2, 2011).

[6] Staff/500, Kaufman/3.

as inputs. PacifiCorp recommends that the parties convene a workshop to discuss a model validation process, such as what inputs should be replaced.

Staff counters that comparing forecast NPC to actual NPC does not provide insight into the source of the model error. Staff notes that in 2015 and 2016 Jim Bridger coal costs were substantially under-forecast compared to actual costs that included a one-time costly Joy Longwall mining accident.[7] Staff explains that 2016 was the first year of the DA/RT adjustment, and by random chance the accident inflated actual costs to match the forecast.

2. Resolution

We are persuaded that PacifiCorp should undertake a limited GRID validation exercise before the 2019 TAM, with the company providing analysis of re-runs of a historical GRID year using actual data, as requested by Staff and ICNU.[8] We direct the parties to meet and discuss the scope and mechanics of such a validation process. While the short time frame will necessarily limit the scope of this validation exercise, with only one year considered and fewer inputs analyzed, we believe a limited validation will help provide more transparency into GRID as we continue to evaluate the rationale behind various GRID adjustments in general and the DA/RT adjustment in particular. We consider this limited validation exercise as an appropriate first step. In the future, we may consider a longer process or use of third-party consultant. To ensure we are up-to-date on the backcast exercise we ask Staff to provide a status report describing the scope and timeline of the process the parties agree to, no later than the first public meeting in January 2018.

C. Day-Ahead/Real-Time (DA/RT) Adjustment

In the 2016 TAM proceeding, we approved PacifiCorp's DA/RT adjustment to capture system balancing costs that are neither included in the company's forward price curve nor modeled in GRID. System balancing transactions occur in GRID to balance hourly load and resources when PacifiCorp does not have enough owned or contracted resources to meet its load, or when the company has excess resources for a given hour.

The DA/RT adjustment has a price component and a volume component to adjust PacifiCorp's system balancing transactions. With the price component, PacifiCorp modifies

[7] Staff/500, Kaufman/5 provides Staff's confidential analysis of this cost. PAC/800, Wilding/37 shows a table where the Joy Longwall costs are adjusted out and NPC is impacted by $4.4 million on an Oregon-allocated basis.

[8] This decision is largely consistent with Staff's request. Staff Response Brief at 6 (Sep 26, 2017) (asking PacifiCorp to convene an initial workshop to address the specific analysis to be done in January 2018, then for PacifiCorp to use best efforts to finish the requested analysis prior to the filing of its 2019 TAM proceeding, and for Staff to report on the progress of this process at a public meeting prior to the company's filing of its 2019 TAM).

the official forward price curve in GRID to separate the balancing purchase and sales prices. The purchase prices are adjusted upward and the sale prices are adjusted downward by an amount equal to the average differential between the company's actual prices and average market prices. The volume component adds additional transaction volumes to NPC outside of GRID to account for the fact that GRID's perfect foresight balances the system with fewer transactions than what is actually required. In practice, the company continually balances its market position—first with monthly and then daily 25 MW standard block products—ultimately rebalancing with hourly products. The additional volumes are priced at the historical average actual prices.

In the 2018 TAM, the DA/RT adjustment increases NPC by $7.13 million on an Oregon-allocated basis.[9] PacifiCorp made a small modification to DA/RT this year by increasing its historical data from four years to five years to calculate the adjustment. PacifiCorp maintains that the DA/RT adjustment has improved the accuracy of the NPC forecast, as shown by 2016 results where forecast NPC almost matched actual NPC. PacifiCorp explains that DA/RT better reflects the market prices available to the company when it transacts in the markets, and better reflects the combination of month, daily, and hourly products that must be used to balance the system.

1. Parties' Positions

CUB, ICNU, and Staff continue to recommend a reduction of the DA/RT. ICNU recommends modifying the adjustment to recognize PacifiCorp's EIM participation. ICNU also believes the adjustment should include transactions that are beyond seven days in advance and not included in DA/RT. Staff contends that the price adder component should be modified with a properly correlated market price and system load, that the volume component of DA/RT should be deleted, and that the validity of DA/RT should be revisited after model validation. CUB and PacifiCorp agreed that the DA/RT calculation will not include years where a PCAM adjustment is triggered.

a. DA/RT Historical Costs and Future Costs

Staff, CUB, and ICNU believe that historic DA/RT costs are not representative of future DA/RT costs. These parties state this is problematic because DA/RT may introduce additional forecast error in the future, and generally prefer to identify the source of NPC variance with model validation and then re-visit DA/RT.

[9] PAC/400, Wilding/25 (Confidential Figure 4 states the company's proposed DA/RT adjustment is $27.7 million total-company, and applying Oregon's 25.741 percent system generation (SG) allocation factor).

Staff argues that replacement of the price adder component with correlated market prices and system load negates the need to normalize DA/RT data.[10] ICNU argues that the EIM has reduced the company's need to incur DA/RT costs and, therefore, the adjustment should only rely on post-EIM data from 2015 and 2016.[11] In response to ICNU's proposal, Staff agrees that the pre-EIM years of 2012 to 2014 had abnormally high DA/RT costs, and adds that the first year of EIM participation, 2015, also had high DA/RT costs, likely due to the EIM learning curve. Staff argues that high DA/RT costs are unlikely to continue, and should be excluded.[12]

ICNU also proposes that the DA/RT adjustment include transactions that have a delivery time of more than one week. ICNU believes that PacifiCorp uses monthly transactions with hedging components to balance its system and these provide a benefit to customers. Staff argues that ICNU's adjustment would be unnecessary if its price adder recommendation were adopted.

PacifiCorp responds that the DA/RT adjustment remains valid post-EIM. PacifiCorp explains that there is now more, not less, uncertainty, because the EIM requires PacifiCorp to balance its system 60 minutes, instead of 30 minutes, in advance. PacifiCorp states that if parties are less willing to transact, there will be higher prices for purchases. PacifiCorp also acknowledges that its 2015 DA/RT costs were higher than the 48-month average and that its 2016 DA/RT costs were lower due to low natural gas process that allowed the company to use more of its own natural gas plants to balance the system. PacifiCorp nonetheless maintains that DA/RT appropriately captures the impact of uncertainty in the company's load and resource position and market prices between the day-ahead and hour-ahead time frame. PacifiCorp also states that use of only two years of historical data runs the risk of creating a non-normalized result.

With regard to the second part of ICNU's argument, PacifiCorp responds that it has limited the DA/RT calculation to transactions with a delivery period of less than one week because those transactions are necessary to balance the company's system and cannot be postponed. PacifiCorp explains that these are short-term firm transactions that are included in the company's indicative filing and final updates based on actual cost and volumes. Regarding hedging, PacifiCorp states that there are no systematic costs or benefits from hedging transactions, as hedges are a cost in some years and a benefit in others, and are a small fraction of DA/RT costs.[13]

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[10] Staff Response Brief at 11.
[11] ICNU/100, Mullins/13; ICNU Response Brief at 16 (Sep 26, 2017).
[12] Staff/500, Kaufman/24; Staff Response Brief at 13.
[13] We grant PacifiCorp's request to take official notice under OAR 860-001-0460(1)(d) of ICNU's Response Brief from Docket No. UE 296 at 7 (Sep 28, 2015).

CUB proposes a "collar mechanism" that would exclude historical years when the company's PCAM is triggered. Staff argues that if the CUB proposal is adopted, the collar should exclude historical years when NPC varies by more than $30 million from the TAM forecast. The company agrees with CUB's proposal to exclude years when the PCAM is triggered, which has a positive $30 million and negative $15 million deadband, sharings provision, and earnings test. PacifiCorp argues that Staff's refinement would not identify years with abnormal DA/RT costs, it would just identify years with a high NPC variance.

b. Additional Volumes Component of DA/RT

The DA/RT additional volumes are priced at the historical average cost with two adjustments, as PacifiCorp begins with the monthly market index, then adds the GRID balancing costs versus market, and the additional balancing cost versus market.[14] Staff recommends eliminating or offsetting the volumes component of the DA/RT adjustment by either making the cost of additional transactions zero, or reducing the NPC forecast to account for the residual value of monthly and daily transactions. Staff is concerned that the DA/RT adjustment is not responsive to the expected number of transactions in GRID. ICNU believes the DA/RT adjustment is really a single adjustment.

2. *Resolution*

We modify the 2018 DA/RT adjustment and direct PacifiCorp to only use post-EIM years to calculate the adjustment. We expect this modification will reduce the DA/RT adjustment by approximately $1.1 million on an Oregon-allocated basis, from $7.1 million to $6.0 million.[15]

We are persuaded by ICNU's evidence that DA/RT costs have decreased since PacifiCorp has participated in the EIM, and ICNU's arguments that future DA/RT costs will trend closer to post-EIM years, compared to the pre-EIM years of 2011 to 2014.[16] Our adoption of post-EIM years for the DA/RT historical period also largely addresses Staff's concern that DA/RT volatility has a particular shape with a spike in years 2012, 2013, and 2014.[17]

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[14] PAC/107, Wilding/15.
[15] PAC/400, Wilding/24 showing the average annual DA/RT adjustment based on 2015-2016 is $23.3 million on a total-company basis, adjusted for Oregon's 25.741 percent system generation (SG) allocation factor. However, we are unsure if this calculation includes changes to both components of DA/RT (prices and additional volumes), and the company shall make the precise calculation in its indicative and final updates.
[16] ICNU/200, Mullins/10 (confidential values demonstrating a significant reduction to the company's system balancing costs relative to monthly average prices in a post-EIM year).
[17] Staff/500, Kaufman/24.

We agree with PacifiCorp that the EIM may make some counterparties less willing to transact in the day-ahead market.[18] However, we find the company's explanation that the EIM influences balancing markets supports ICNU's and Staff's position to only use post-EIM years for the DA/RT adjustment. For example, EIM participants like PacifiCorp are deciding in the day-ahead time frame whether to transact in the forward market or to position their generator commitment to potentially benefit from cost savings that the EIM may deliver with real-time optimized dispatch.[19] We do not question the reasonableness of the company's balancing transactions, but rather simply recognize that there is an overlap in the hour-ahead balancing occurring between the individual balancing authority areas (BAAs), and then sub-hourly, EIM-wide optimized dispatch across all the participating BAAs.[20] It is this relationship that supports a DA/RT adjustment based only on post-EIM years.[21]

We direct PacifiCorp to use post-EIM years for DA/RT in the 2018 TAM, and as a starting place for the 2019 TAM. Because we would like to see how post-EIM years represent DA/RT costs in the 2019 TAM, and also because we want parties and the company to be open to DA/RT refinements that may come out of the model validation process, we do not reach the parties' other proposed DA/RT adjustments. Thus we make no finding on ICNU's argument that the DA/RT should include system balancing transactions greater than seven days, or Staff's recommendation to eliminate the volume component of DA/RT. Despite PacifiCorp's agreement, we also do not address the merits of CUB's collar mechanism that would exclude historical years when the PCAM is triggered because it would not affect the 2018 TAM, as the PCAM has never been triggered. We will continue to evaluate parties' arguments on whether the adjustment accurately represents the company's system balancing costs.[22]

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[18] PAC/400, Wilding/28-29 ("In addition, because other counterparties know of PacifiCorp's time limits for transactions, they make less competitive bids, knowing that even if PacifiCorp does not accept, they can sell to other counterparties closer to their 20-minute transmission scheduling deadline.").
[19] PAC/107, Wilding/30 (explaining that PacifiCorp maximizes its EIM participating resources). ICNU/200, Mullins/9 ("the Company now has the ability to bid capacity to be dispatched into the EIM, rather than sell that capacity into the hour-ahead market."). Staff/500, Kaufman/26 ("The Company appears to be scheduling dispatchable resources in order to have greater participation in the EIM market. In fact, the Company even claims that it runs its coal plants when they are uneconomic in order to capture EIM benefits. If the EIM market is driving the Company to schedule thermal resources when it would have otherwise made market purchases than it is reasonable to expect that participation in the EIM has affected the Company's DA/RT costs.").
[20] PAC/402, Wilding/1. The NPC study shows "System Balancing Sales" at seven trading hubs, as well as "EIM exports".
[21] PAC/902, Brown/22 (E3 study stating that the EIM's sub-hourly processes increase the efficiency of resolving imbalances).
[22] ICNU Cross-Answering Brief (Oct 5, 2017) (explaining that Staff, CUB, and ICNU are focused on the accuracy of each discrete element of NPC, as opposed to overall NPC forecast).

D. Coal

Parties raise numerous issues related to PacifiCorp's forecasted costs of its coal-fired resources. These issues, which often overlap, address coal plant dispatch costs as well as the costs of coal supply through affiliate mines or third party coal supply agreements.

Staff challenges PacifiCorp's methodology of forecasting its dispatch of these resources generally, and Sierra Club challenges the company's forecasted dispatch of the Naughton plant specifically. Staff also questions costs of the coal supply agreement for the Cholla plant. Parties also raised numerous issues on both coal dispatch issues and coal supply issues, which are generally resolved by PacifiCorp's decision to hold workshops as discussed below.

1. Coal Plant Dispatch

a. Parties' Positions

Staff recommends that PacifiCorp adjust its GRID model to include economic shutdown of coal plants. Staff explains that during periods of low energy costs, GRID operates coal units at minimum operating levels, a practice that Staff believes prevents GRID from selecting the lowest cost dispatch of plants. Staff proposes that, in light of GRID's use of minimum operating levels for thermal plants, PacifiCorp be directed to analyze and develop a modeling technique that would allow for the shutdown of certain high cost coal plants during periods of low marginal costs. Staff states this could be accomplished by performing additional planned outages to PacifiCorp's planned outage GRID input files. Staff also recommends that we require PacifiCorp to calculate the NPC of each of its coal shutdown scenarios, and select the scenario with the lowest NPC, inclusive of the no shutdown scenario.

PacifiCorp responds that Staff's proposal is not consistent with the company's actual historic operations. The company emphasizes that, in a normal year, it does not economically shut down coal plants. PacifiCorp acknowledges that it did shut down some coal plants the past two years due to abnormal market conditions caused by historically low natural gas prices in 2016 and historically high hydro generation in 2017. PacifiCorp contends that those years were unusual and that in normal years, such as 2013 to 2015, it only extended maintenance-related outages for several hours or days. PacifiCorp states that when a coal plant is uneconomic to dispatch, GRID will model the plant at its minimum capacity, consistent with actual operations. PacifiCorp concludes that a normalized forecast of coal plant dispatch should not include prolonged economic shutdowns.

b. Resolution

We decline any adjustments to PacifiCorp's forecasted coal plant dispatch in this proceeding because an adjustment in this proceeding has not been adequately supported. We review GRID dispatch issues to determine whether the company is meeting its obligation to operate prudently, with prudent unit commitment and dispatch decisions that minimize costs. PacifiCorp has explained that its current GRID modeling reflects historic, normalized practices regarding economic shutdowns of coal units. Staff's general comparisons to the natural gas screening process are not sufficient to support an adjustment in the 2018 TAM.

However, we are interested in the points raised by Staff that PacifiCorp's actual operations may be changing under evolving market conditions. The company explains that a coal dispatch adjustment would require changes to inter-related coal supply information such as minimum take requirements. Thus, we add coal plant economic outage modeling to the list of topics for parties to discuss in the coal workshops.[23] We also add a reporting requirement, and direct PacifiCorp to make a presentation at a public meeting before the 2019 TAM summarizing the coal workshops. We specifically ask the company to summarize any proposals identified to increase the accuracy of coal dispatch modeling due to economic outages, any proposals to address long-term coal contract issues, and any proposals to include variable (O&M) in the TAM. We recognize that some of the coal issues may overlap with the GRID validation exercise. At the public meeting we will also ask the parties to summarize their viewpoints of the workshops.

2. Cholla Plant Liquidated Damages

A majority of PacifiCorp's coal plants are fueled at least in part with coal supply agreements or transportation agreements that require the company to commit to substantial minimum purchase levels (known as "minimum take" or "take-or-pay" provisions).[24] Several of these agreements also require PacifiCorp to pay for liquidated damages if the company fails to take minimum volumes. PacifiCorp forecasts these liquidated damages as part of its coal operations, and they vary due to changes in a plant's expected dispatch.

PacifiCorp's initial filing forecasts liquidated damages to Peabody Energy because the volume of coal PacifiCorp will purchase for the Cholla plant is less than the liquidated damage minimum requirements in the coal supply agreement.

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[23] PAC/1112 lists the six points the parties agreed to discuss in a coal workshop.

[24] PAC/200, Ralston/15 contains the confidential coal and transportation contract information.

a. Parties' Positions

Staff believes PacifiCorp's calculation of liquidated damages is excessive and should be reduced. Staff faults PacifiCorp's decision to reduce its coal stockpile in 2018 instead of purchasing additional coal and also argues that the costs associated with drawing down the Cholla coal pile should be attributed to 2016 NPC rather than 2018 NPC.

PacifiCorp responds that it reasonably increased the stockpile above target levels in 2016 to avoid higher liquidated damages in effect at that time, and is now drawing down the stockpile at a lower liquidated damages rate. PacifiCorp explains that overly large stockpiles come with carrying costs to the company and reduced operational flexibility. PacifiCorp maintains that its multi-year coal supply agreement is reasonable and consistent with industry standards in an illiquid market.[25]

b. Resolution

We decline any adjustment related to liquidated damages. PacifiCorp's reply update reflects an updated nomination for Cholla, with an uptick in the purchased coal volume, a slight reduction in the liquidated damages, and an inventory level close to its historic target.[26] The company's target is reasonable under the terms of its current contract. Regarding the PacifiCorp's coal purchases in 2016 that lead to the large stockpile, we find the company's response persuasive that it acted reasonably under the terms of various interim purchase agreements that were in effect during Peabody Energy's bankruptcy.[27]

3. Coal Supply Agreements

a. Parties' Positions

During the course of these proceedings, Sierra Club and Staff raised numerous issues related to PacifiCorp's long-term coal contracts and its coal procurement strategies. In its direct testimony, Sierra Club initially made four recommendations to address its concerns that certain provisions in PacifiCorp's coal fuel contracts might result in the uneconomic dispatch of coal units, including Naughton Unit 3. That unit was initially slated to convert to natural gas in early 2018, but PacifiCorp now plans to run that unit through 2018 following the state of Wyoming's decision to extend the unit's permit to January 2019.

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[25] PAC/200, Ralston/21-23 (describing PacifiCorp's confidential coal supply agreement for Cholla).
[26] PAC/600, Ralston/8 (confidential purchase volume, liquidated damages amount, and stockpile amount).
[27] PAC/600, Ralston/9 (describing current confidential coal supply agreement and amendment); PAC/1000, Ralston/6 (describing 2016 purchase agreements).

Staff also shares concerns and requests that PacifiCorp provide a written report detailing all of the considerations and processes of entering into new long-term coal contracts, to be filed before the 2019 TAM, and to include all reasonable information requested by the parties.

PacifiCorp has addressed the concerns raised by Sierra Club by agreeing to hold a workshop on long-term coal contracts and to include variable O&M in the company's GRID modeling. With regard to Staff's recommendation, PacifiCorp responds that it prefers a workshop approach over a written report due to the complexities of the company's coal procurement strategy and processes.

PacifiCorp adds that it continues to work on the long-term fuel plan for the Jim Bridger plant, with a target completion date of December 2017. PacifiCorp held two party workshops after the 2017 TAM, identified different fuel plan scenarios, and has selected the least-cost, least-risk option.[28] Supply changes would require at least four years to implement, and the company will assess possible supply changes through its long-term fuel plan. The company agrees to meet again with the parties as the long-term fuel plan moves into the final stage.

For the near-term, PacifiCorp will continue its current fueling strategy, with approximately two-thirds of the coal supply sourced from Bridger Coal Company and one-third from the Black Butte mine. It continues to negotiate the coal-supply agreement with the Black Butte mine and the transportation agreement with Union Pacific Railroad.

b. Resolution

In response to Staff's request for a written report, we direct PacifiCorp to update and expand its 2010 fleet-wide coal inventory policies and procedures with the current supply information provided by witnesses Ralston and Schwartz in this proceeding.[29] We direct the company to include this updated study as an attachment to initial testimony in the 2019 TAM. We require this update because we typically receive coal planning information in a piecemeal fashion and this makes it difficult to track year over year.[30] This updated report will serve as a starting place, and we will consider any party suggestions for an expanded or altered report in the future.

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[28] PacifiCorp's fuel plan for the Jim Bridger plant is largely confidential and discussed in detail at PAC/200, Ralston/5-11.

[29] We take official notice under OAR 860-001-0460(1)(d) of Staff/212, Kaufman/1, Docket No. UE 307.

[30] For example, in the annual TAM proceedings PacifiCorp provides updated contract and price information, and occasionally includes a longer-term mine plan; the bi-annual IRP proceedings describe life-of-plant fueling plans, and have on occasion included a long-term fueling plan; and one time Staff audit reports or long-term fuel plans are occasionally filed as compliance reports in TAM proceedings.

We also agree with PacifiCorp's and Sierra Club's joint proposal for a workshop on long-term coal contract issues and proposal for including variable O&M in the TAM. We direct PacifiCorp to convene this workshop. The contract issues the parties have agreed to discuss include: the company's process for long-term coal contracts, managing risk in those contracts, how the contract provisions impact dispatch in GRID, and regulatory review of contracts.[31] As described above, we include a reporting requirement for the company and parties to summarize these discussions at a public meeting before the 2019 TAM.

We also approve PacifiCorp's plan to finalize an updated long-term Jim Bridger fuel plan, which should be filed both in this docket and as an attachment to initial testimony in the 2019 TAM. Jim Bridger coal costs continue to be significant and will require on-going monitoring. PacifiCorp's confidential testimony and workshop presentations explain some of the issues, such as delivery limitations, mining constraints, and pricing in an illiquid market.[32]

We also approve PacifiCorp's continuation of its near term Jim Bridger fueling strategy. The company states that it is working to optimize Jim Bridger plant fueling considering all sources.[33]

E. EIM Costs and Benefits

The EIM is a real-time balancing market that optimizes generator dispatch every five and 15 minutes within and between the PacifiCorp and CAISO balancing authority areas. PacifiCorp has participated in the EIM since late 2014, and includes the benefits and costs associated with participation in the EIM in the TAM filing. EIM benefits are reflected as a reduction to the NPC forecast. EIM costs, including capital and operations and maintenance expense, are added to the TAM to match the benefits.

The largest category of EIM benefits are inter-regional dispatch benefits, which are the EIM-facilitated transactions between CAISO, PacifiCorp, and other EIM participants. In last year's TAM CUB argued that the company unreasonably limited inter-regional benefits based on available transmission. As a result of the post-TAM workshops, the company adopted CUB's proposal and removed the transmission constraint. PacifiCorp now estimates the EIM benefits from exports to CAISO based on a dollars per month approach.[34]

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[31] PAC/1112 (Scope of Workshop document).

[32] PAC/700, Schwartz 4-5 ("Except for the Dave Johnston plant, the coal supply options continue to be extremely limited today, with few producers who can supply the plants.").

[33] PAC/201, Ralston/24.

[34] PAC/107, Wilding/61-62 (explaining the calculation methodology and the market cap used to mitigate the potential of overstating the sale benefit).

1. *Parties' Positions*

Staff recommends adjustment to PacifiCorp's EIM-related forecast to address forecasting lag and more accurately reflect the expanding market. With regard to forecasting lag, Staff explains that PacifiCorp's methodology has consistently produced EIM benefit estimates that are accurate for the previous year's actual but under-forecast the next year. To correct the estimates that are a "year behind," Staff proposes an adjustment based on half of the actual growth rate from historical data. Previously, PacifiCorp has used a forecast that is based on the average of 12 months of EIM data. This year, PacifiCorp's forecast is based on the most recent six months of data to be more representative of the market in 2018. PacifiCorp multiplies the most recent six months by two and then adds amounts for new entrants (Portland General Electric Co. and Idaho Power Co.), as well as solar generation over-supply conditions in California.[35] Staff believes that it is too early to remove the growth trend from the forecast. Staff recommends a $1.26 million Oregon-allocated increase in EIM benefits.[36] Staff uses a 12-month historical average, adds the company's estimate for new entrants, and applies a 50 percent growth rate to the forecast 2018 benefits.

PacifiCorp acknowledges that past EIM benefits have understated inter-regional benefits and this led to the company's significant increase of EIM benefits in this case. PacifiCorp states that, despite its expectation for diminishing EIM returns, it has included a robust growth rate reflecting EIM benefits that are 45 percent higher than the most recent 12 months.[37] PacifiCorp believes that Staff has double-counted the impact of new entrants by adding the benefits and applying the 50 percent growth rate to the incremental benefits.

2. *Resolution*

We adopt PacifiCorp's EIM benefit forecast as shown in its reply and surrebuttal testimony, subject to the indicative and final update.[38] The company's reply filing increased EIM benefits by $10.6 million over the initial filing, and we believe much of the company's increase is in response to Staff's analysis in opening testimony. We decline any further adjustments to PacifiCorp's EIM forecast, because we conclude the company's forecast is reasonable in light of the evidence in this proceeding for three reasons. First, PacifiCorp uses a 45 percent EIM growth rate, which is well above CAISO's calculation of a flat or declining growth for PacifiCorp.[39] Second, the company's forecast for 2018 also includes an adjustment for new entrants and California solar generation over-supply conditions, which is

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[35] PAC/900, Brown/3, 6 (confidential amount of external adjustment to account for new market entrants and over-supply conditions in California caused by increased solar generation).
[36] PAC/801, Wilding/2 (shows the dollar value of all adjustments).
[37] PAC/900, Brown 3 (stating EIM benefits are 45 percent higher than the most recent 12 months of data).
[38] PAC/900, Brown/1 (confidential forecast values).
[39] PAC/900, Brown/14.

well above E3's forecast used in the initial filing. Third, the company has annualized the most recent six months of EIM data to capture recent market changes.

F. QF Costs

PacifiCorp's filing includes costs associated with four PPAs with QFs that are expected to reach commercial operation in 2018 and have not previously been included in rates, increasing NPC by $5.6 million (total company).[40] The company attests to their projected online dates, stating that, based on the information known to it at the time of filing, it has a commercially reasonable good faith belief that these QFs will reach commercial operation before or during the forecast period.[41] For existing QFs with PPAs terminating in 2018, PacifiCorp assumes these QFs will continue selling to the company at the most recent avoided cost rates.

1. Parties' Positions

CUB contends that PacifiCorp's attestation method of forecasting QF costs is not working. CUB presents confidential evidence showing that the company has over forecast the cost of QFs in every month since the 2017 TAM order was issued in December 2016.[42] To fix the QF forecast error, CUB proposes to derate the contracts using a rolling three year average QF contract delay rate (CDR) that would apply to all new QFs.

To accomplish this, CUB proposes looking at the 2014, 2015, and 2016 final TAM forecasts and comparing the forecast commercial operation date (COD) to the actual COD date for all QF projects. All delayed projects would be averaged to produce an average delay. The average delay days would then be applied to new QFs in the current TAM forecast. CUB's CDR proposal reduces NPC by $353,000 on an Oregon-allocated basis.

In response, PacifiCorp agrees to implement a CDR but proposes two additional steps. First, PacifiCorp proposes to weight the CDR based on the nameplate capacity of each QF. PacifiCorp explains that QF costs are volumetric and a larger QF costs more than a smaller QF. Second, PacifiCorp proposes we limit the delay days to those within the rate effective period. PacifiCorp explains that if a QF is delayed before or after the TAM year in question, it does not affect the TAM forecast. PacifiCorp adds that calculating the CDR using only the delayed days from the TAM year creates a clean break when calculating the three year average where delays may span more than one TAM year. PacifiCorp's recommendations

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[40] PAC/100, Wilding/11.

[41] *In re PacifiCorp d/b/a Pacific Power's 2015 Transition Adjustment Mechanism*, Docket No. UE 287, Order No. 14-331 at 5 (Oct 1, 2014) (adopting a settlement that added the attestation process).

[42] CUB/201, Jenks/2.

reduce NPC by $204,000 on an Oregon-allocated basis. Staff supports PacifiCorp's recommendation.

2. Resolution

We adopt CUB's CDR proposal for the 2018 TAM, reducing forecast NPC by approximately $353,000 on an Oregon-allocated basis, subject to PacifiCorp's indicative and final updates. For the 2019 TAM we direct the company to weight the CDR by QF size to more accurately reflect the rate impact of forecast errors. We do not adopt PacifiCorp's proposal to weight the CDR by QF size in the 2018 TAM because the record in this proceeding is not clear on the steps of that calculation.

We agree with CUB that PacifiCorp should use a three year rolling average of delays to produce a CDR, apply this CDR to the CODs reported in the indicative update, and adjust the TAM year forecast based on the delay days within the TAM year. Thus, as CUB explains, a CDR adjustment to a contract that was forecast to begin on November 15, (before the TAM year) would only affect the TAM forecast if the CDR is greater than 45 days. Similarly, a CDR adjustment to a contract that was scheduled to have a COD on December 15 (during the TAM year) would only affect the first 16 days of operation, because those are the only days included in the TAM.[43]

The attestation process is designed to allow PacifiCorp to produce an accurate QF forecast so that it fully recovers new QF costs. CUB has revealed, however, that QFs do not communicate accurate CODs to the company, and that the company seems to not consistently update the CODs in the TAM forecast.[44] We agree with CUB that the company will likely be more careful in the future with updating CODs before the indicative update. The rolling average CDR should incentivize the company to use the most updated CODs in the future, in order to reduce the CDR going forward. However, if we do not see an improvement in the attestation accuracy going forward, we will likely consider a more detailed process that requires the company executive to specify what communication he or she has had with the QF to verify its COD.

G. Direct Access

Calpine renews two arguments from prior TAM proceedings related to direct access. First, Calpine continues to argue that direct access customers should receive a credit to reflect the value of the RECs that are freed up because of a direct access customer's departure. In

[43] CUB Response Brief at 14-15 (Sep 26, 2017).
[44] *Id.* at 10 (confidential table summarizing the delayed QFs from 2016 and citing CUB's cross exhibits with email correspondence).

response to Calpine's arguments in the 2017 TAM proceeding, we asked the parties to discuss this issue in post-TAM workshops, with a focus on the potential benefits that may derive at the time PacifiCorp must take substantive action to comply with its renewable portfolio standard (RPS) targets.[45] In workshops, the parties generally agreed that the TAM should account for the value of RECs in some manner, but did not agree on a methodology to calculate the value of freed-up RECs.

Second, Calpine again argues that the opt-out charge should decrease, rather than increase, in years 6 through 10 to account for accumulated depreciation. In the 2017 TAM order, we directed PacifiCorp to include a historical time series of fixed generation costs included in its direct access opt-out charge, broken down by its components (e.g., capital, O&M) as a check on the reasonableness of its forecasts used for determining the opt-out charge for direct access customers participating in the 5-year permanent direct access program. In the 2018 TAM filing PacifiCorp included Exhibit 110 with fixed generation components that have increased steadily over the past 10 years.

1. RECs

a. Parties' Positions

PacifiCorp proposes a credit based on the future value of RECs, discounted to present value. PacifiCorp's first year of a REC compliance shortfall is 2028, and to calculate the credit the company applied the purchase price for RECs that are deliverable in 2028 to the amount of freed up RECs, and then discounted that amount back into 2018 dollars and applied it to the volume of direct access load, which is then levelized over the direct access period.[46] The credit varies from $0.08/MWh for a future $1 REC to $1.19/MWh for a future $15 REC.[47] PacifiCorp maintains that it is appropriate to discount the RECs to present value because the RECs freed up do not have value to the company until the freed up RECs extend PacifiCorp's RPS compliance shortfall.

Calpine asks that the REC credit be based on either the current value of RECs or that PacifiCorp transfer RECs on behalf of direct access customers as an alternative. Calpine explains that the company's REC credit unreasonably assumes RECs have no value until 2028.

PacifiCorp responds that its REC credit is consistent with Order No. 16-482, where we found that freed up RECs may benefit other customers by altering the point in time when

[45] *In the Matter of PacifiCorp's 2017 Transition Adjustment Mechanism,* Docket No. UE 307, Order No. 16-482 (Dec 20, 2016).
[46] PacifiCorp will value RECs based on its recent RFP results for long-term REC purchases.
[47] PAC/107, Wilding/68.

PacifiCorp would need to take resource actions to comply with the RPS. Regarding the alternative of transferring freed up RECs, the company responds that a workshop will be required to establish a framework for future REC transfers in lieu of a credit. Thus, PacifiCorp asks that we approve its proposed REC credit here and initiate workshops or another process to develop a framework to allow REC transfers in the future. Staff supports this approach.

PacifiCorp further explains that its REC credit will apply to 1- and 3-year opt-out customers, and that 5-year opt-out customers are ineligible for this adjustment since they do not contribute to Schedule 203.[48] PacifiCorp states that customers that may elect 5-year direct access in the future should continue to be subject to current Schedule 203 charges because the company included these loads in its RPS compliance planning at the time of the REC purchases.

b. Resolution

We adopt PacifiCorp's REC proposal to go into effect for the 2018 TAM. We find the company's proposal to be consistent with our guidance from the 2017 TAM order. PacifiCorp proposes REC values based on its recent RFP results for long-term REC purchases, discounted to a present value.

We recognize that the valuation of RECs has been a primary point of disagreement among the parties for three TAM proceedings, with parties explaining the REC markets are volatile and illiquid.[49] Parties believe that REC transfers may be a simpler solution, and we are interested in this option. PacifiCorp began working on two proposals for REC transfers before this TAM,[50] and proposes to conduct another workshop on REC transfers before the 2019 TAM. We agree with the company's workshop proposal, and add a requirement for the 2019 TAM. In the 2019 TAM, the company is to present its best proposal for REC transfers, so that parties may weigh in and build a full record on this issue that will enable us to decide whether REC transfers are practical and feasible.

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[48] PAC/100, Wilding/35 (citing *In the Matter of PacifiCorp, dba Pacific Power, Update to Schedule 203, Renewable Resource Deferral Supply Service Adjustment*, Docket No. UE 313, Order No. 17-019 (Jan 24, 2017) (the Commission found that one and three-year direct access customers are subject to Schedule 203, the Renewable Resource Deferral Supply Service Adjustment, which recovers the costs of RECs that were purchased following the company's 2016 REC RFP)).
[49] PAC/107, Wilding/58.
[50] PAC/107, Wilding/65 (a pro-rata share of RECs generated or acquired during the opt-out years, or a pro-rata share of RECs used for compliance during the opt-out years).

2. *Opt-out Charge*

a. *Parties' Positions*

PacifiCorp states that its opt-out calculation holds fixed generation costs flat in years six through ten on a real basis, adjusting them only for inflation. PacifiCorp states the opt-out charge must include investments in existing plants, and that its inflation escalator used to calculate the consumer opt-out charge is reasonable. PacifiCorp states the cost drivers that increase the company's fixed generation costs over time more than offset the accumulated depreciation that decreases fixed generation costs.

Calpine argues that the opt-out charge should decrease, rather than increase, in years 6 through 10 to account for accumulated depreciation. Calpine makes a two part argument—that the company's charge should neither add new investments to rate base, such as environmental upgrades to extend coal plant lives, nor ignore the effect of depreciation of the existing rate base for a closed pool of generation investments.

b. *Resolution*

We will allow PacifiCorp's opt-out charge to go into effect for the 2018 TAM as presented. The company complied with our 2017 TAM directive by including an exhibit listing a historical time series from 2006 to 2015 of fixed generation costs by component, beginning with total rate base, then adding return on rate base, O&M, depreciation, amortization, and taxes from 2006 to 2015. This exhibit shows an increasing revenue requirement over the ten years.[51] The company has explained that it uses an inflation adjustor to develop a forecast of Schedule 200 costs for years six through ten and reducing those costs back to calculate a levelized payment to be made in years one though five.[52]

We are concerned, however, with PacifiCorp's new arguments asserting that incremental generation should be allowed in the year six through ten forecast.[53] Thus, we provide new, clear guidance to further explain our intent for the opt-out charge. This guidance is necessary because the opt-out charge is relatively new and the calculation methodology was summarily established in our review of a contested stipulation.[54]

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[51] PAC/110, Wilding/1.

[52] PAC/400, Wilding/57.

[53] PacifiCorp Opening Brief at 47-48 (Sep 14, 2017) ("PacifiCorp disagrees that the consumer opt-out charge cannot account for incremental generation investments after year five."); PAC/400, Wilding/56-59.

[54] *Re PacifiCorp's Transition Adjustment, Five-Year Cost of Service Opt-Out,* Docket No. UE 267, Order No. 15-060 at 6 (Feb 24, 2016) ("We therefore resolve the only contested issue regarding the rate components of Schedule 296 by adopting the consumer opt-out charge as it was presented in modified form by PacifiCorp in reply testimony.")

We direct PacifiCorp to more clearly demonstrate in the 2019 TAM that its opt-out charge meets the following criteria. First, the company may use a modest inflation adjustor to forecast year 6 through 10 costs. Second, the company should not include any new incremental generation in the years 6 through 10 forecast. Third, the company should account for depreciation. With these three requirements, we expect the opt-out charge to fall somewhere in-between the company's current calculation and Calpine's suggestion, netting the company's 2.5 percent inflation escalator and Calpine's 8.38 percent depreciation rate. These numbers are approximate, and PacifiCorp is directed to provide transparency into this calculation in the 2019 TAM with explanatory testimony and supporting exhibits.

IV. ORDER

IT IS ORDERED that:

1. Advice No. 17-002 is permanently suspended.

2. PacifiCorp, dba Pacific Power, shall update its net power costs to reflect the changes to the DA/RT adjustment and QF forecast adopted in this order to establish its Transition Adjustment Mechanism NPC for calendar year 2018 and file its tariffs to be effective January 1, 2018.

3. Commission Staff is directed to provide a status report on PacifiCorp's limited model validation proposal no later than the first public meeting in January 2018. PacifiCorp is directed to complete a limited model validation exercise before the 2019 TAM.

4. PacifiCorp is directed to include in the 2019 TAM an updated 2010 coal inventory report.

5. PacifiCorp and parties are directed to participate in a coal workshop and the workshop scope is expanded to include modeling economic outages of coal plants. PacifiCorp is directed to make a presentation at a public meeting before the 2019 TAM summarizing proposals identified at the workshops and the parties will also summarize their viewpoints of the workshop.

6. PacifiCorp is directed to conduct a party workshop on REC transfers before the 2019 TAM filing. PacifiCorp is directed to include in 2019 TAM initial testimony a proposal for REC transfers for parties and the Commission to consider.

7. PacifiCorp is directed to demonstrate the mechanics of its opt-out calculation in its 2019 TAM filing in compliance with the guidelines in this order.

Made, entered, and effective NOV 01 2017.

Lisa D. Hardie
Chair

Stephen M. Bloom
Commissioner

Megan W. Decker
Commissioner

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